Memorandum

Florida Department of
Environmental Protection

To: Trina Vielhauer

From: A.A. Linero

Date: November 19, 2010

Subject: DEP File No. 0510032-001-AC (PSD-FL-412)
Southeast Renewable Fuels (SRF), LLC
Sweet Sorghum-to-Ethanol Advanced Biorefinery

Attached for your review is a Revised Draft Air Construction Permit package for the construction of the SRF Sweet Sorghum-to-Ethanol Advanced Biorefinery (including a cogeneration power plant) which will be located south of Clewiston in Hendry County, Florida.

The revised package will be issued pursuant to the Settlement Stipulation executed by the Department and SRF on November 19, 2010 resolving matters related to the earlier Draft Permit package that was issued on October 28, 2010. The previous notice was not published by the applicant.

The attached Technical Evaluation and Preliminary Determination document provides a detailed description of the project and the rationale for permit issuance. This project is subject to the rules for the Prevention of Significant Deterioration (PSD).

Attachments

TLV/aal

Florida Department of Environmental Protection

Bob Martinez Center
2600 Blairstone Road
Tallahassee, Florida 32399-2400

Charlie Crist
Governor
Jeff Kottkamp
Lt. Governor
Mimi Drew
Secretary

Sent by Electronic Mail – Received Receipt Requested

dmarkley@serenewablefuels.com
Mr. Don Markley
Executive Vice President
Southeast Renewable Fuels (SRF), LLC
6424 NW 5th Way
Fort Lauderdale, Florida 33309

Re: DEP File No. 0510032-001-AC (PSD-FL-412)
Sweet Sorghum-to-Ethanol Advanced Biorefinery

Dear Mr. Markley:

On March 19, 2010 you submitted an application (most recently updated on October 12, 2010), for an air construction permit subject to the preconstruction review requirements of Rule 62-212.400, Florida Administrative Code (F.A.C.), for the Prevention of Significant Deterioration (PSD) of Air Quality.

The project is the construction of a sweet sorghum-to-ethanol advanced biorefinery (including biomass cogeneration boiler) that will be located south of Clewiston, Florida.

The original Draft Permit and associated documents that were transmitted by the cover letter dated October 28, 2010 are hereby withdrawn and replaced by those enclosed herewith.

Enclosed are the following documents: Written Notice of Intent to Issue Air Permit; Public Notice of Intent to Issue Air Permit; Technical Evaluation and Preliminary Determination; and a Draft Permit with Appendices.

The Public Notice of Intent to Issue Air Permit is the actual notice that you must have published in the legal advertisement section of a newspaper of general circulation in the area affected by this project. If you have any questions, please contact Alvaro Linero, P.E. at 850/921-9523.

Sincerely,

Trina L Vielhauer 11/19/10

Trina Vielhauer, Chief (Date)
Bureau of Air Regulation

Enclosures

TLV/aal

WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMIT

In the Matter of an
Application for Air Permit by:

Southeast Renewable Fuels (SRF), LLC
6424 NW 5th Way
Fort Lauderdale, Florida 33309
Authorized Representative: Mr. Don Markley,
Executive Vice President

DEP File No. 0510032-001-AC (PSD-FL-412)
Sweet Sorghum-to-Ethanol Advanced Biorefinery
Hendry County, Florida

Facility Location: The SRF facility will be located just East of County Road (CR) 835 at the intersection with Hill Grade Road and approximately 13 miles south southwest of Clewiston/Lake Okeechobee in Hendry County.

Project: The project involves the construction of a 22.11 million gallons per year sweet sorghum-to-ethanol advanced biorefinery based on sweet sorghum grown on adjacent farmland. The sweet sorghum juice will be squeezed from the sorghum stalks, fermented, distilled and blended to make a range of ethanol/gasoline products. The leftover stalk fiber (bagasse), other parts of the plant (field residue) and wood (to augment the bagasse/field residue material) will be used as fuel in a biomass boiler to make process steam and up to 30 megawatts (gross) of electricity. Ultra low sulfur distillate fuel oil or propane will be used for boiler startup, flame stabilization and shutdown. The applicant also plans to use sweet sorghum molasses in the ethanol process when sweet sorghum is not available. The project is subject to the preconstruction review requirements of Rule 62-212.400, Florida Administrative Code (F.A.C.) for the Prevention of Significant Deterioration of Air Quality requiring a best available control technology (BACT) determination.

The previous written notice and accompanying documents transmitted on October 28, 2010 are hereby withdrawn and replaced with the present revised notice and accompanying documents.

Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters 62-4, 62-210 and 62-212, F.A.C. The proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Florida Department of Environmental Protection's Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Bureau of Air Regulation's physical address is 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301 and the mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation's phone number is 850/488-0114.

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

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

Public Notice: Pursuant to Section 403.815, F.S. and Rules 62-110.106 and 62-210.350, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Permit (Public Notice). The Public Notice shall be published one time only as soon as possible in the legal advertisement section of a newspaper of general circulation in the area affected by this project. The newspaper used must meet the requirements of Sections 50.011 and 50.031, F.S. in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Permitting Authority at the address or phone number listed above. Pursuant to Rule 62-110.106(5) and (9), F.A.C., the applicant shall provide proof of publication to the Permitting Authority at the above address within 7 days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rule 62-110.106(11), F.A.C.

Comments: The Permitting Authority will accept written comments concerning the proposed Draft Permit and requests for a public meeting for a period of 30 days from the date of publication of the Public Notice. Written comments must be received by the Permitting Authority by close of business (5:00 p.m.) on or before the end of this 30-day period. In addition, if a public meeting is requested within the 30-day comment period and conducted by the Permitting Authority, any oral and written comments received during the public meeting will also be considered by the Permitting Authority. If timely received comments result in a significant change to the Draft Permit, the Permitting Authority shall revise the Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

Petitions: A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed with (received by) the Department's Agency Clerk in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000 (Telephone: 850/245-2241; Fax: 850/245-2303). Petitions filed by the applicant or any of the parties listed below must be filed within 14 days of receipt of this Written Notice of Intent to Issue Air Permit. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within 14 days of publication of the attached Public Notice or within fourteen 14 days of receipt of this Written Notice of Intent to Issue Air Permit, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority for notice of agency action may file a petition within 14 days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention (in a proceeding initiated by another party) will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Permitting Authority's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner; the name, address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of when and how each petitioner received notice of the agency action or proposed decision; (d) A statement of all disputed issues of material fact; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action including an explanation of how the alleged facts relate to the specific rules or statutes; and, (g) A statement of the relief sought by the petitioner, stating precisely the action the petitioner wishes the agency to take with respect to the agency's proposed action. A petition that does not dispute the material facts upon which the Permitting Authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C. Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Permitting Authority's final action may be different from the position taken by it in this Written Notice of Intent to Issue Air Permit. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation: Mediation is not available in this proceeding.

Executed in Tallahassee, Florida.

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Written Notice of Intent to Issue Air Permit Package (including the Written Notice of Intent to Issue Air Permit, the Public Notice of Intent to Issue Air Permit, the Technical Evaluation and Preliminary Determination and the Draft Permit with Appendices) was sent by electronic mail, or link to these documents made available electronically on a publicly assessable server, with received receipt requested before close of business on 11/19/10 to the persons listed below.

Don Markley, SRF: dmarkley@serenewablefuels.com
Ajaya Saytal, 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.

(Clerk) 11/19/10 (Date)

ADDENDUM TO

TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION

APPLICANT

Southeast Renewable Fuels, LLC (SRF)
6424 Northwest 5^{th} Way
Fort Lauderdale, FL 33309

PROJECT

Sweet Sorghum-to-Ethanol Advanced Biorefinery
ARMS Facility ID No. 0510032

DEP File No. 0510032-001-AC (PSD-FL-412)

COUNTY

Hendry County, Florida

PERMITTING AUTHORITY

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

November 19, 2010
(Addendum to Technical Evaluation and Preliminary Determination dated October 28, 2010)

1. Project Information

On October 28, 2010 the Florida Department of Environmental Protection (Department) distributed the "Intent to Issue Air Permit" to construct a 22.11 million gallons per year (MGPY) sweet sorghum-to-ethanol advanced biorefinery based on sweet sorghum grown on adjacent farmland. The leftover stalk fiber (bagasse) and wood (to augment the bagasse will be used as fuel in a biomass boiler to make process steam and up to 30 megawatts (gross) of electricity. The SRF facility will be located just East of County Road (CR) 835 at the intersection with Hill Grade Road and approximately 13 miles south southwest of Clewiston/Lake Okeechobee in Hendry County.

The distributed package included the Department's Draft Air Construction Permit, the "Written Intent to Issue Air Permit," the "Technical Evaluation and Preliminary Determination (TEPD)," and the "Public Notice of Intent to Issue Air Permit."

The project triggered the state rules for the prevention of significant deterioration (PSD) at Section 62-212.400, Florida Administrative Code (F.A.C.) but not the federal PSD rules at 40 Code of Federal Regulations (CFR), Part 52, Section 52.21.

The Department sent copies of the package to various agencies and the governing body of the nearby Seminole Reservation. SRF did not publish the notice and on November 9, 2010 requested an extension of time in which to file a Petition for Administrative Proceedings pursuant to Rule 62-110.106(4), Florida Administrative Code (F.A.C.). The extension was granted by the Department on November 17, 2010.

The Department and applicant met on November 15 to discuss and resolve their issues and avoid the need for such an administrative hearing. The meeting initiated a process that culminated in a settlement stipulation that was signed by the Department and SRF on November 19, 2010 and also resulted in a revised package which was distributed on November 19 including this addendum to the TEPD. The key issues and their resolution are discussed in the following sections.

2. Removal of Requirement to Install at least one Catalyst

The permit included a requirement to install a selective catalytic reduction (SCR) system or an oxidation catalyst (Ox-cat). The typical function of SCR is to control nitrogen oxides (NO_X) in order to comply with best available control technology (BACT) limits. The typical function of Ox-cat is to control carbon monoxide (CO) and volatile organic compounds (VOC) in order to comply with BACT limits.

Either catalyst is also effective in the control of organic hazardous air pollutants (HAP) including dioxin and furan (D/F). Refer to the Table 1 below reproduced from the previous TEPD. The applicant estimated that the project would emit less than 10 TPY of any individual HAP and less than 25 TPY of all HAP.

Table 1 – Applicant's Estimated PTE of HAP from the SRF Project in TPY

Pollutant	HCl	HF	Cl_2	Key Metal HAP [1]	Key Organic HAP [2,3]	Other HAP	Total
Boiler	0.91	0.03	2.66	0.99	13.87	0.31	18.77
Ethanol Process					3.46		3.46
Other Sources						0.75 [4]	0.75
Total	0.91	0.03	2.66	0.99	17.33	1.06	22.98

1. Key metal HAP for the boiler consist of chromium (Cr), lead (Pb), manganese (Mn) and nickel (Ni).
2. Key organic HAP for the boiler consist of acetaldenhyde (C_2H_4O), acrolein (C_3H_4O), benzene (C_6H_6), Bis(2-ethylhexyl) phthalate ($C_{24}H_{38}O_4$), 1,4-Dichlorobenzene ($C_6H_4Cl_2$), formaldehyde (CH_2O), hexane (C_6H_{14}), styrene (C_8H_8), toluene (C_7H_8), polycyclic aromatic hydrocarbon/polycyclic organic matter (PAH/POM).
3. Key Organic HAP for the ethanol process consists of: acetaldehyde (C_2H_4O), acrolein (C_3H_4O), formaldehyde (CH_2O) and methanol (CH_4O).
4. This includes all HAP for all other sources such as fugitive emissions from equipment leaks and tanks.

Because the applicant has not yet determined whether a bubbling fluidized bed (BFB) bed or a grate stoker boiler will be constructed, it is not yet certain which catalyst (if any) will be required to meet the Department's BACT For example, the recently permitted 39.4 MGPY Highlands Ethanol Facility (HEF) project (the project most similar to SRF) will rely on a BFB boiler and selective non-catalytic reduction (SNCR) to meet the NO_X BACT limit and good combustion practices (GCP) to meet the CO BACT limit (i.e. without Ox-cat).

Additionally, the USEPA will finalize two maximum achievable control technology (MACT) rules as 40 CFR Part 63, Subparts DDDDD and JJJJJJ applicable to major and area sources respectively for the kind of boilers under consideration by SRF. The final rules will affect the type of boiler selected by the applicant and will affect the actual control equipment installed.

SRF provided the Department with a set of measures which they believe will reduce emissions of HCl to the point where the Department will have reasonable assurance that the project will not be a major source of HAP without the specific requirement of a catalyst to effect lower organic HAP emissions.

Paraphrasing, the key measures are:

- SRF will not collect and use sorghum harvest residue (such as leaves and seed clusters) as fuel in the boiler;
- SRF will specify in its contracts with growers that incidental adherence of such parts of the plants to the harvested stalks is to be minimized (limited to 5 percent or less);
- SRF will design the previously planned wet cyclone located between the furnace and the electrostatic precipitator (ESP) in such a manner that HCl control is enhanced;
- SRF will design the planned dry sorbent injection system (DSIS) including the use of reagents such as trona to further enhance HCl control; and
- SRF plans to review the kinds of fertilizers used by growers and strive to work with the growers to reduce use of chlorine-containing fertilizers.

With such measures, SRF believes and the Department accepts that HCl emissions can be reduced to 2.0 TPY thus obviating the requirement to install SCR catalyst or Ox-cat to suppress organic HAP emissions to values less than estimated in Table 1. The applicant may elect to install a catalyst based upon boiler type selected and future MACT requirements. The permit allows the installation of a catalyst should the applicant decide to do so.

3. HCl Continuous Emission Monitoring System (CEMS)

The original draft permit allowed SRF greater emissions of HCl than estimated requested (8.0 TPY versus 0.91 TPY). SRF has since requested a limit of 2.0 TPY of HCl. Therefore the estimated HAP emissions will be 24.1 TPY. The applicant has requested that the Department remove the requirements in the draft permit to install a HCl and HF-CEMS in light of the applicant's low emission estimates for these pollutants.

By removing the catalyst requirement, organic HAP emissions will not be suppressed and a higher HCl emission rate can no longer be accommodated within a HAP limitation less than 25 TPY. Whereas the HCl-CEMS was required to insure HCl emissions did not exceed 10 TPY, now it is equally needed to insure that total HAP will be less than 25 TPY.

The Department will remove the requirement to install a HF-CEMS because there is good reason to believe that emissions of HF will be an order of magnitude less than HCl. If HCl emissions are less than or equal to 2.0 TPY then HF emissions will very likely be less than 0.2 TPY and the 25 TPY total HAP ceiling will not be breached due to excessive HF emissions.

4. Ammonia (NH_3) Slip

The applicant will comply with the NO_X limit given in the draft permit of 0.10 pounds per million Btu (lb/mmBtu) or 0.08 lb/mmBtu based on the installation of a grate stoker boiler or a BFB boiler, respectively. At the same time, the project will comply with a limit of 0.10 lb CO/mmBtu regardless of the type of boiler installed.

The applicant advised that FuelTech, a well-known supplier of SNCR systems, will guarantee NH_3 slip of 25 parts per million by volume, dry (ppmvd) for the BFB boiler (35 ppmvd for the grate stoker boiler) rather than 10 ppmvd as required in the previously distributed draft permit. For reference, 10 ppmvd NH_3 slip is readily achievable while complying with the NO_X BACT limits if SCR catalyst is used.

The Department will provide for the greater NH_3 slip requested by SRF and notes the following:

- Some of the NH_3 slip will tend to reduce HCl emissions because it will react with HCl to form ammonium chloride (NH_4Cl);
- Some of the NH_3 slip will tend to react with small amounts of sulfur dioxide (SO_2), sulfur trioxide (SO_3) and sulfuric acid mist (H_2SO_4) present in the exhaust to form ammoniated sulfates and sulfites; and
- Ammoniated chlorides and sulfates/sulfites will contribute to particulate matter (PM/PM_{10}) and visible emissions (opacity).

5. PM/PM_{10} and VE Limits

The applicant requested that the PM/PM_{10} limits from the boiler be specified as 0.015 rather than 0.01 pounds per million Btu (lb/mmBtu). The two limits are for practical purposes almost equal in terms of the expressed significant figures.

In view of the greater NH_3 slip requested and the resulting additional ammoniated chlorides and sulfates/sulfites, PM/PM_{10} the Department will adjust the limit to 0.015 lb/mmBtu as requested by the applicant. However the Department has limited VE to 10 percent (%), which will encourage the applicant to design and operate the SNCR or SCR system such that NH_3 emissions are actually minimized. Examples of such designs were given in the original TEPD as exemplified by the Covanta VLN™ system employing GCP and SNCR.

It is also possible to design a wet scrubber before the stack and stripper that can remove NH_4Cl and provide for the recovery and reuse of NH_3, thus minimizing slip and VE, achieving good NO_X removal, and reducing the cost of reagent without necessarily installing a catalyst.

6. SO_2 Limit

The applicant originally requested separate limits of 0.025 and 0.11 lb SO_2/mmBtu from the boiler when firing bagasse/wood and bagasse/wood/biogas combinations respectively. The Department required that SRF operate a hydrogen sulfide (H_2S) scrubber whenever biogas is used to supplement the bagasse/wood boiler fuel and to meet a single limit of 0.025 lb SO_2/mmBtu whether or not biogas is burned in the boiler.

The applicant requested an increase to 0.06 lb SO_2/mmBtu as a single limit and clarification that the H_2S scrubber and other equipment related to SO_2 control must be operated only to the extent necessary to meet the single limit. The other SO_2 control equipment includes a dry sorbent injection system (DSIS) and limestone injection into the furnace (particularly the BFB boiler).

The requested limit is equal to the BACT SO_2 limit assigned to the HEF project. The Department will make the change as requested.

7. Comparison of SRF and HEF Project BACT Determinations

Table 2 is a comparison of the SRF and HEF ethanol project BACT determinations.

Table 2 – Applicant's Estimated PTE of HAP from the SRF Project in TPY

Project Location	CO	VOC	NO_X	PM/PM_{10} [a]	SO_2	NH_3	VE
HEF , Highlands County BFB Boiler (2010)	0.10 30-day GCP	0.005 stack test GCP	0.075 30-day SNCR [b]	0.01 (f) Stack test fabric filter	0.06 30-day BFB limestone	10 ppmvd	10%
SRF, Hendry County BFB Boiler (2010)	0.10 30-day GCP	0.010 stack test GCP	0.08 30-day SNCR [b]	0.015 (f) stack test ESP	0.06 30-day BFB limestone sorbent in ducts	25 ppmvd	10%
SRF, Hendry County Grate Stoker (2010)	0.10 30-day GCP	0.010 stack test GCP	0.10 30-day SNCR [b]	0.015 (f) stack test ESP	0.06 30-day sorbent in ducts	35 ppmvd	10%

a. (f) means filterable PM/PM10 only and excludes condensable PM/PM_{10}
b. SCR is allowed in conjunction with or as an alternative to SCR

Although the emission limits from the SRF project will be somewhat greater than those from the HEF project, they are not much different. Both projects were permitted under the Department's PSD program and required BACT determinations although both of them would not be considered major stationary sources subject to PSD and BACT per the federal PSD regulations.

8. Conclusion

The Department confirms its previous conclusion that the proposed project will comply with all applicable state and federal air pollution control regulations as conditioned by the revised Draft Permit.

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

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
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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)

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.

- 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.

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.]

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;

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]

{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]

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

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.]

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.]

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.]

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,w ill 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]

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 **Specified 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,SC R 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.

{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

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 [1]
	240 TPY	Rule 62-4.070(3), F.A.C.	12-month rolling by CEMS [1]
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,Meta l 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

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 (acetaldehyde), 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,

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

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

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,an hydrous 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]

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.]

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.}

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.]

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.

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.]

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.]

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.]

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,G eneral Control Device Requirements.
[NSPS Subpart A and Rule 62-4.070(3), F.A.C.]

EMISSIONS STANDARDS,T ESTING 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.

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.]

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.

- 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.

[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]

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.]

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.]

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]

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.]

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]

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)]

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]

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)]

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.

[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]

TECHNICAL EVALUATION

&

PRELIMINARY DETERMINATION

APPLICANT

Southeast Renewable Fuels, LLC
5525 NW 15th Ave., Suite 301 A
Fort Lauderdale, FL 33309

PROJECT

Sweet Sorghum-to-Ethanol Advanced Biorefinery
ARMS Facility ID No. 0510032

DEP File No. 0510032-001-AC (PSD-FL-412)

COUNTY

Hendry County, Florida

PERMITTING AUTHORITY

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

October 28,2 010

1. APPLICATION INFORMATION

1.1. Applicant Name and Address

Southeast Renewable Fuels (SRF), LLC
5525 Northwest 15th Avenue, Suite 301A
Fort Lauderdale, Florida 33440

Authorized Representative:

1.2. Key Dates

- March 19, 2010 — Received a Prevention of Significant Deterioration (PSD) air construction permit application from SRF.
- April 16 — Department issued first request for additional information (RAI).
- May 14 — Department received response to first RAI from SRF.
- June 16 — Department issued status letter advising SRF that application is complete and also that EPA's proposed sulfur dioxide (SO_2) 1-hour primary national ambient air quality standard (NAAQS) might apply to the project based on final rule issuance.
- June 22 — EPA published the 1-hour SO_2 primary NAAQS final rule with an effective date of August 23, 2010.
- July 28 — Department received a modification to the application with modified emission rates, stack heights, controls and modeling to address the new 1-hour SO_2 NAAQS, impacts on ground level concentrations of other pollutants and revised boiler nitrogen oxides (NO_X) emission proposal.
- August 6 — Department issued status letter advising SRF of receipt of the additional information and conveying information regarding available NO_X controls and matters related to emission estimates of hazardous air pollutants (HAP).
- August 24 — Department received response to August 6 status letter.
- August 26 — Department issued status letter advising SRF of its review of the additional information in the August 24 response to the previous status letter.
- August 27 — Department provided SRF with a preliminary version of the draft air construction permit for the project.
- September 9 — Department received comments from SRF through Golder Associates regarding preliminary version of draft air construction permit.
- October 12 — Department received additional information and modifications of proposed emission limits.
- October 28 — Department issued Draft Permit decision for SRF and posted documents.

1.3. Facility Location

The SRF facility will be located just East of County Road (CR) 835 at the intersection with Hill Grade Road and approximately 13 miles south southwest of Clewiston/Lake Okeechobee in Hendry County. The UTM coordinates are Zone 17; 502.0 kilometers (km) East and 2,940.9 km North. The location of Hendry County is shown in Figure 1. The location of the proposed site is shown in Figure 2.

Hendry County is bounded by Lee County to the west, Glades County to the north, Collier County to the south, Palm Beach County to the east and Broward County to the southeast. Lake Okeechobee is located immediately northeast of Hendry County. The Big Cypress Seminole Indian Reservation is located approximately 18 miles south southeast of the site entrance. Most of Hendry County is agricultural.

The proposed SRF facility will be located on 60 acres of land within property currently owned by Aspring. Figures 3 and 4 are photographs taken at or near the site entrance. The land is presently used for agricultural crops such as sugar cane. Sweet sorghum will be grown on approximately 25,000 acres of land to supply the proposed SRF facility. Figure 5 shows a preliminary layout of the facility.

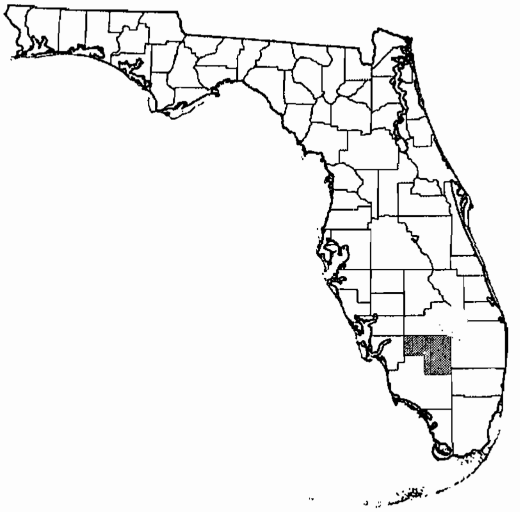

Figure 1 - Hendry County, Florida

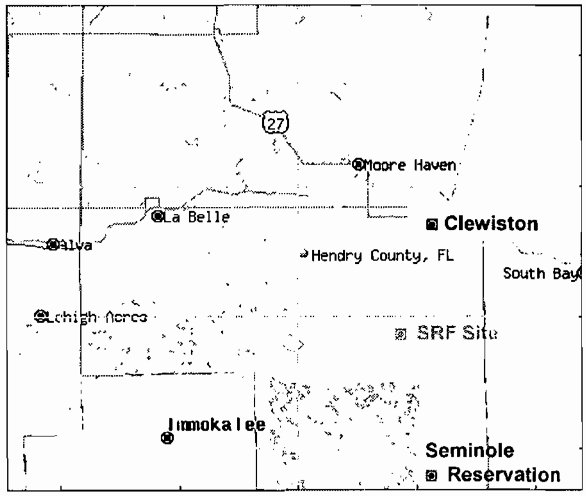

Figure 2 - Proposed Location of SRF, Hendry County

The nearest PSD Class I area is the large Everglades National Park (ENP) that straddles Monroe, Collier and Miami-Dade Counties. The nearest boundary point in the ENP is located 85 km south of the proposed SRF site.

Figure 3 - Entrance to Proposed SRF Site

Figure 4 - Terrain North of the Site Entrance

1.4. Project Description

The applicant proposes to construct a sweet sorghum-to-ethanol advanced biorefinery with a capacity of 22.11 million gallons per year (MGPY). The sweet sorghum will be grown on adjacent farmland. The sweet sorghum juice will be squeezed from the sorghum stalks, fermented, distilled and blended to make a range of ethanol/gasoline products. The leftover stalk fiber (bagasse) and other parts of the plant (harvest field residue) will be combusted in a cogeneration biomass boiler to make process steam and up to 30 megawatts (MW, gross) of electricity. The applicant also plans to use sweet sorghum molasses in the ethanol process when sweet sorghum is not available. Wood and yard waste will be used as a backup and supplemental fuel for the biomass boiler.

Figure 6 includes a picture taken of the Department's representative at an experimental sorghum plot managed by the University of Florida (UF) Institute for Food and Agricultural Sciences (IFAS) in Citra, Florida, a picture of the Department's representative with sorghum stalk samples and residue, and a picture (source: IFAS presentation) of an experimental plot in Hastings, Florida.

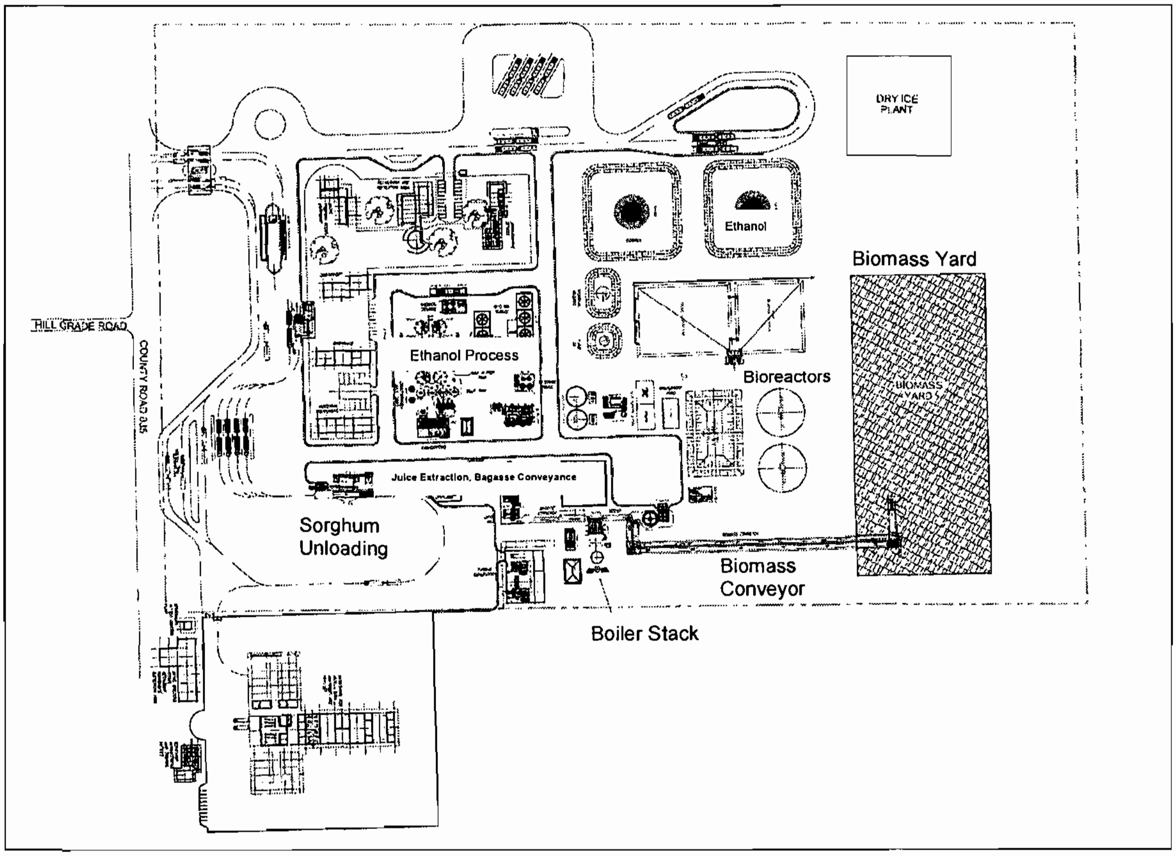

Figure 5 – Preliminary Layout of Future SRF Facility

Figure 6 – IFAS Sorghum Plot in Citra, Stalks and Residue from Citra, Seed clusters at Hastings

The ethanol will be made from the sorghum juice and not the cellulosic fractions. The product is nevertheless considered by some to be cellulosic ethanol. The reason is that the cellulosic/lignin fractions (bagasse and field residue) will be used in the steam and power production that support the ethanol production. The project is similar to the recently-permitted Highlands Ethanol facility (HEF) except that the latter is based on conversion/fermentation of the cellulosic/hemicellulosic fractions to make ethanol and use of the residual high-lignin stillage to make steam.

The SRF process is akin to conventional sugar production practiced in the area, except that the juice is fermented and distilled to produce ethanol rather than evaporated and refined to produce sugar. It is also similar (differing only in the crop) to the production of ethanol from sugarcane, which is widely practiced in Brazil.

The main process steps are:

- Sorghum and other biomass receiving, handling and feeding;
- Juice extraction and evaporation;
- Ethanol production (including fermentation, distillation and dehydration);
- Product storage, blending and loadout;
- Steam and electrical production; and
- Wastewater treatment.

Table 1 indicates the emissions units (EU) associated with this project. Figure 7, provided by SRF, is a simplified process flow diagram for the project with only the key EU indicated.

Table 1 - Process Steps Comprising the SRF by EU.

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

2. PROCESS DESCRIPTION

Refer to Figure 7 as the reference for the following discussion of the SRF sweet sorghum to ethanol process.

2.1. <u>(E.U. 001) Material Handling and Preparation</u>

Sorghum feedstock receiving. Harvested sorghum will arrive from the adjacent agricultural fields to the production facility via trucks. 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. The feed table is equipped with chains that convey the sorghum toward the main conveyor that feeds the juice extraction system.

Supplemental boiler fuel receiving. Sorghum harvest residue from the fields will also be received at the facility for burning in the boiler. Wood, including yard trash, will be received from local suppliers.

Sorghum cutting, shredding and conveyance. The sorghum passes through two sets of revolving sorghum knives and one heavy-duty shredder. From the shredder, the sorghum passes to a high-speed belt carrier then to the diffuser feed carrier. Any excess sorghum is returned to the high-speed belt conveyor via the excess sorghum carrier and a chute.

The diffuser consists of a horizontal slat-type conveyor with a fixed bottom consisting of perforated screens. Beneath the screens, several semi-cylindrical transversal juice receivers will be installed. Maceration water is fed into the juice trough and falls onto the sorghum mat, percolates through the fibers, passes across the screen, and is collected in the last juice receiver.

As the sorghum moves across the diffuser it is progressively washed of its sucrose content. The wash water sucrose is circulated in a countercurrent manner such that it is progressively concentrated in the direction of the incoming sorghum.

The washed sorghum (now bagasse) is pressed in a roller system to approximately 50 percent (%) moisture and is then transferred to the biomass boiler or to a biomass storage pile. The juice is centrifuged to remove large particles, milk of lime is added to adjust the acidity (pH) as needed and the juice is screened and stored. Centrifuged particles are returned to the diffuser, while the final wash water is recirculated to the diffuser.

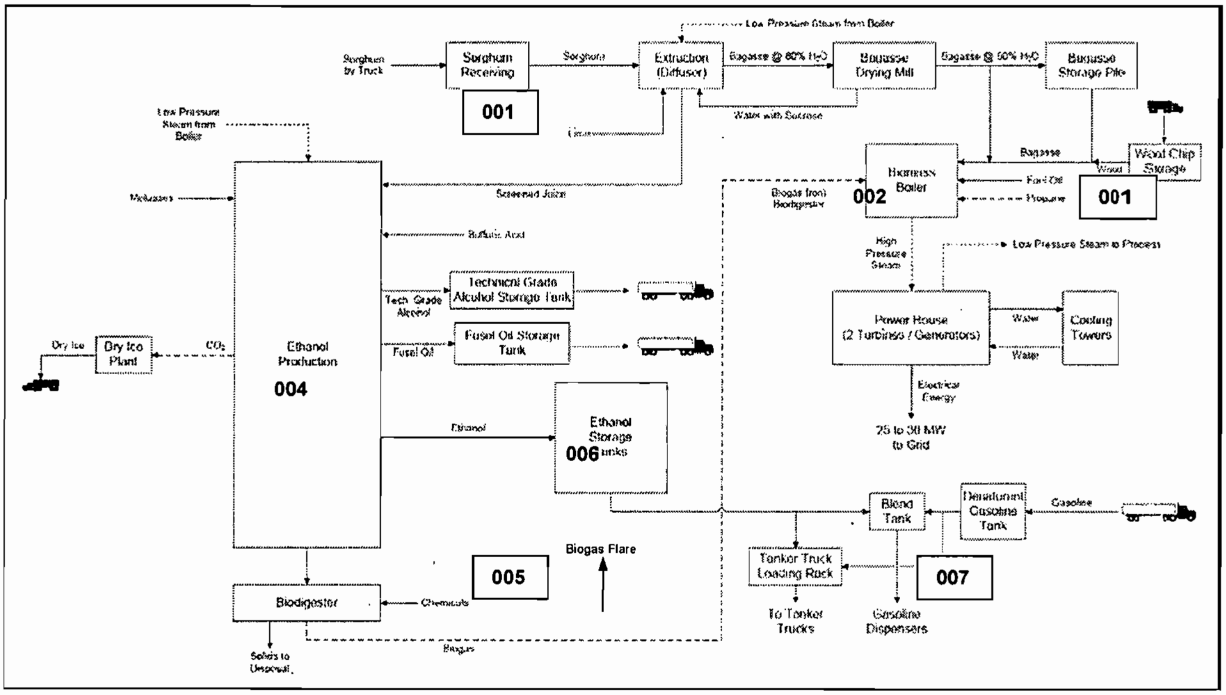

Figure 7 – Simplified Diagram of SRF Sorghum to Ethanol and Power Facility

2.2. <u>(E.U. 002) Biomass Boiler Steam and Power Production</u>

The project will employ one biomass boiler with a maximum capacity of 536 million Btu per hour (mmBtu/hr on a 4-hr basis) and 488 mmBtu/hr on a 24-hr basis. The design will either be a grate stoker boiler or a bubbling fluidized bed (BFB) boiler. The boiler will combust sorghum bagasse, sorghum harvest residue, biogas from the wastewater treatment process, woody biomass, and yard trash.

The applicant proposes to use very low sulfur distillate (VLSD) fuel oil ($\leq$ 0.05% sulfur) or propane as startup, shutdown and flame stabilization fuels. A simplified process flow diagram for the steam and power operations including pollution proposed control equipment is shown in Figure 8.

The proposed pollution control systems as described by the applicant include:

- Selective non-catalytic reduction (SNCR) based on urea [$(NH_2)_2CO$] injection and a modern overfire air (OFA) system for minimizing emissions of nitrogen oxides (NO_X);
- Low-NO_X burners (LNB) for firing natural gas and VLSD fuel oil;
- Mechanical collectors and an electrostatic precipitator (ESP) will be used for control of particulate matter (PM) and metals emissions;

- Use of very low-sulfur fuels and a dry sorbent injection system (DSIS) to control emissions of sulfur dioxide (SO_2) and other acid gases;
- Use of clean biomass and fossil fuels will also control emissions of mercury (Hg) and lead (Pb); and
- The modern OFA system will also control emissions of carbon monoxide (CO) and volatile organic compounds (VOC).

For reference, control of PM also accomplishes control of PM with a diameter less than 10 micrometers (PM_{10}). Control/minimization of PM/PM_{10}, NO_X, SO_2, VOC, sulfuric acid mist (SAM - H_2SO_4), and ammonia (NH_3) emissions will also control PM with an aerodynamic diameter less than 2.5 micrometers ($PM_{2.5}$). Measures such as OFA and LNB fall into the category of good combustion practices (GCP).

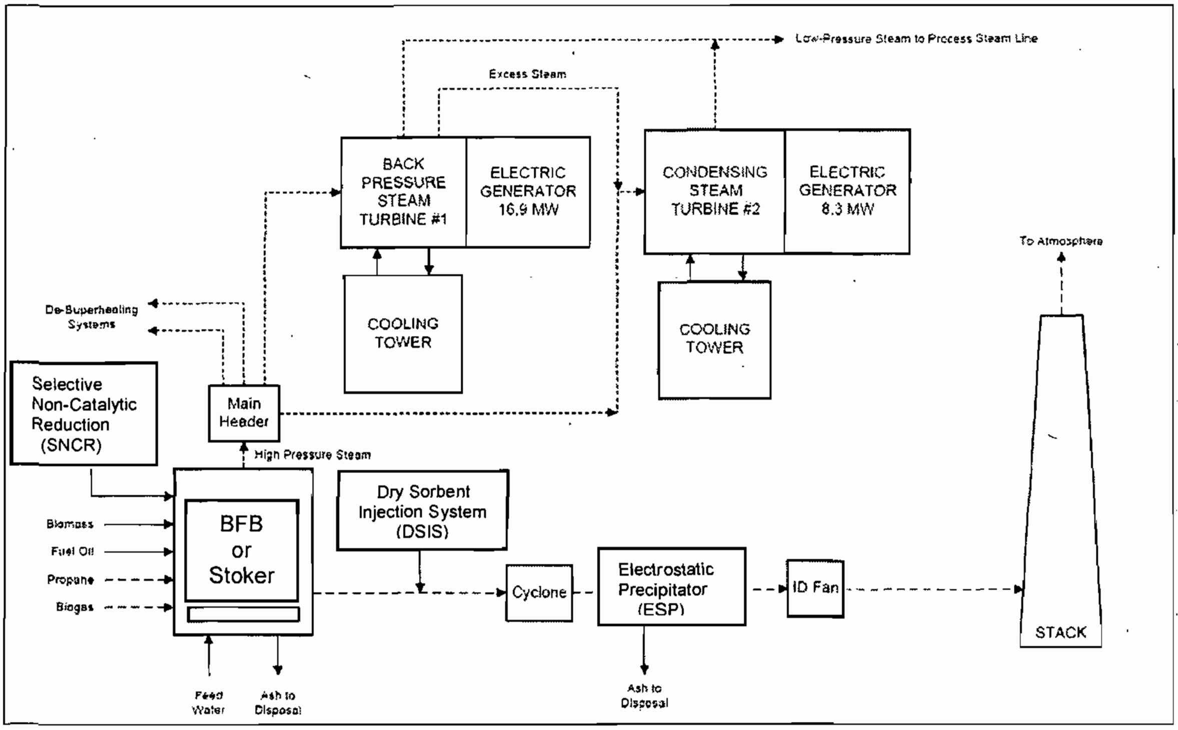

Figure 8 – Simplified Diagram of Applicant's Proposed SRF Steam and Electricity Production Cycles

2.3. (E.U. 003) Cooling Towers

The proposed SRF facility will have three mechanical draft cooling towers. The towers are a machinery cooling tower (one cell), a condensing set cooling tower (three cells) and a process cooling tower (three cells).

2.4. (E.U. 004) Ethanol Process

The ethanol process is shown in Figure 9 and consists of juice extraction, evaporation, fermentation, distillation and dehydration.

Juice Evaporation (004a). 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 vapors from the heaters/evaporators are passed through heat exchangers in the juice extraction area to heat the juice recirculating within the diffuser. The vapors are condensed in the heat exchangers, and the condensate from the evaporators is separated into clean and foul condensate. Foul condensate is removed by gravity to the foul condensate buffer tank before being pumped into either the condensate receiving tank in the diffuser or to the wastewater treatment system. The clean condensate is collected in the clean condensate buffer tank and is then pumped to the deaerator.

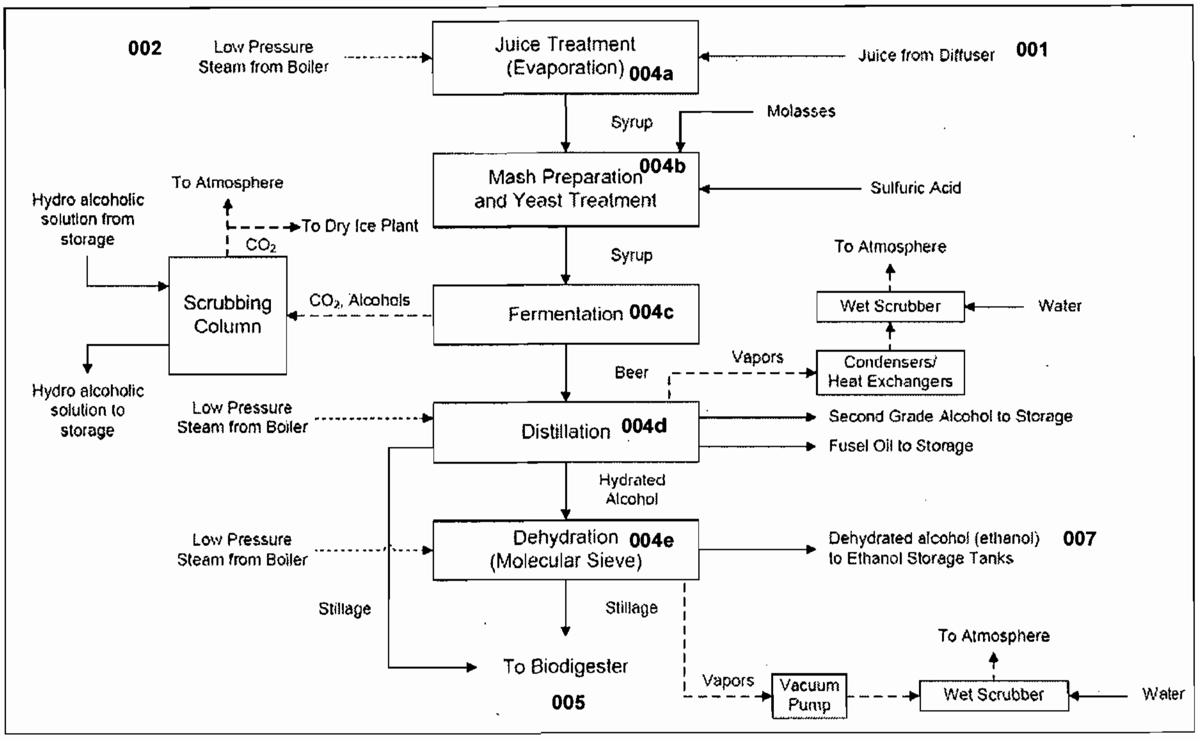

Figure 9 – Simplified Diagram of SRF Sweet Sorghum to Ethanol Production Process

The remaining clean juice is gradually concentrated to form syrup during the evaporation process. The syrup is stored in the concentrated juice storage tank. Process steam from the boiler and from the evaporation process is recycled throughout the juice treatment process.

Mash Preparation and Yeast Treatment (004b). Concentrated juice or purchased molasses from the evaporation process storage tank is pumped into the fermenter vessels. Mechanical stirrers are used to mix the yeast as it is being diluted with water. Sulfuric acid is added to adjust the acidity (pH). Antibiotics, nourishing substances, and compressed air can also be added as needed. The mechanical stirrers continue to stir the yeast cream for several hours before it is pumped to a fermentation vessel.

Fermentation (004c). During fermentation, sugars contained in the mash are transformed to ethyl alcohol (ethanol), carbon dioxide (CO_2) and secondary compounds such as other alcohols, aldehydes, glycerin, succinic acid, furfural, etc. The fermentation vessels produce beer, which is pumped to a holding tank before being sent to the beer filters. The beer filters use centrifugal force to separate yeast cream from the beer. The cleaned beer containing approximately 8 percent (%) ethanol is pumped to the distillation process via the beer buffer tank. Solid substances include yeast, bacteria, non-fermentable sugars, minerals salts, albuminoidal substances, and other miscellaneous substances. Yeast can be treated or sold as a by-product.

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. The washing column uses a hydro-alcoholic solution to entrain the ethanol contained in the gas stream. Recovered ethanol is recycled back into the fermentation process. CO_2, free from alcohol, is released to the atmosphere or will be sent to an adjacent dry ice plant for recovery.

The following equipment will be used in steps 004b and 004c: a sulfuric acid tank; one (1) mash cooler; one (1) wine cooler; one (1) yeast treatment tank; seven (7) fermenters; one (1) beer tank; one (1) beer filter; two (2) yeast centrifuges; one (1) beer buffet tank; and one CO_2 scrubbing column.

Distillation (004d). Beer from storage is sent to a pre-heater/condenser and then a beer/stillage regenerative heat exchanger. Ethanol present in the beer is extracted by distillation in column equipped with trays, with contact elements between the liquid and vapor phases. Columns are heated to different temperatures to separate specific volatile substances independently. Vapors generated by one column are used to heat other columns to increase thermal efficiency. To heat the column, steam or vapors can be injected directly into the columns, or a re-boiler can be used. Several condensers are used in the system to condensate vapors exiting the top of the distillation columns, to recover ethanol and other components. The vapor will lastly be sent through a washing column (wet scrubber) to further recover any remaining ethanol or trace organics.

Hydrated ethanol 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. Extracted stillage from the distillation column is pumped through the beer/stillage exchanger then transferred to the biodigester system. Technical grade ethanol from the distillation columns is pumped to storage. Fusel oil (five-carbon amyl alcohols) from the columns is sent through a decanter where impurities are separated. The purified fusel oil is sent to storage, while the impurities are recycled back to beer storage tank.

The equipment used in step 004d includes: one (1) distillation column; one (1) degassing column; one (1) heads concentrate column; one (1) rectification column; one (1) fusel oil decanter; one (1) hydrated alcohol tank; one CO_2 washing column.

Dehydration (004e). Hydrated ethanol from the distillation step undergoes dehydration with a molecular sieve to produce ethanol at 99.67% purity. The process is performed in a batch operation where the hydrated ethanol, heated by steam, passes through beds of siliporite (zeolite). Siliporite is an absorption medium with a molecular structure capable of physically capturing water molecules while allowing ethanol to pass through. Several siliporite vessels are used in parallel.

The final ethanol is discharged into a holding tank. Flashed vapors from the tank are sent through two condensers, and collected liquid and any remaining vapors are returned to the holding tank. From the holding tank the ethanol is transferred to a metering tank and the sent to an ethanol product storage tank.

The siliporite beds must be regenerated periodically by vacuum. A vacuum pump is used for this purpose. The vapors with small traces of ethanol are collected in two condensers prior to the vacuum pump. The recovered permeate from the condensers is sent to a storage tank and then back to distillation. The gases exhausting the vacuum pump are sent through a wet scrubber washing column that uses water as the scrubbing media. The gases then exhaust the atmosphere.

The equipment to be used at this stage are: one (1) hydrated alcohol heater; two (2) zeolite absorber (molecular sieve) vessels; condensers and coolers; one (1) dehydrated alcohol holding tank; one (1) permeate collector tank; and one CO_2 washing column.

Air Pollution Control Equipment. Three scrubbers will be used in the ethanol production area to control emissions of ethanol and VOC. These will be incorporated into the fermentation, distillation and dehydration steps. The fermentation wet scrubber will use hydro-alcohol as the scrubbing liquid to maximize ethanol removal in the scrubber. The distillation wet scrubber will use water as the scrubbing liquid. The dehydration wet scrubber will control air emissions from the molecular sieves and vacuum pump and will use water as the scrubbing liquid. According to the applicant, the three scrubbers will have ethanol/VOC removal efficiencies of 98%.

2.5. (E.U. 005) Bioreactors and Biogas Flare

Collected wastewaters (including stillage, foul condensate, sludge, blowdowns and ash) are treated in two anaerobic bioreactors to reduce the chemical and biological oxygen demand (COD and BOD) prior to discharging the wastewaters. Wastewater with a high organic content is gradually degraded by methanogenic bacteria to produce "biogas" and anaerobic sludge. The biogas produced from the methane reactors will consist of a maximum of 2% hydrogen sulfide (H_2S). The remainder will be largely methane (CH_4) and CO_2. The biogas after passing through a wet scrubber to remove H_2S is sent to the biomass boiler when the boiler is operating or to the biogas flare if the boiler is shut down (maximum of 30 days per year).

The equipment to be used at this stage is: two methane bioreactors; one (1) degas tank and one (1) flare for biogas generated by the bioreactors.

2.6. (E.U. 006) Volatile Organic Liquid Storage Tanks: Denaturant/Gasoline, Alcohol, Blends

The facility will contain several volatile organic liquids (VOL) organic storage tanks for ethanol, second grade alcohol, denaturant/gasoline, and blending tanks. The following tanks will be controlled by internal floating roofs or pressure relief valves in lieu thereof and in accordance with Title 40 of the Code of Federal Regulations (CFR), Part 60, Subpart Kb (40 CFR 60, Subpart Kb):

- Two final products storage tanks, each with a capacity of 875,000 gallons (gal) to store ethanol;
- One second-grade (technical) alcohol storage tank with a capacity of 153,220 gal;
- One gasoline tank with a capacity of 250,000 gal; and
- One blend tank (gasoline/ethanol) with a capacity of 50,000 gal.

The following tanks are not subject to 40 CFR 60, Subpart Kb and will have vertical fixed roofs (VFR):

- One large (47,551 gal) and one small (1,849 gal) fusel oil storage tanks;
- One VLSD fuel oil diesel fuel oil tank with a capacity of 50,000 gal;
- One ultralow sulfur distillate (ULSD) fuel oil ($\leq$ 0.0015% sulfur) tank with a capacity of 5,000 gal;
- One hydrated alcohol/off-specification (spec) product tank with a capacity of 2,642 gal;
- One second grade alcohol metering tank with a capacity of 2,642 gal; and
- One final product metering tank with a capacity of 7,925 gal.

The facility will include several liquid chemical storage tanks to store sulfuric acid, phosphoric acid and ammonia or urea. All of these tanks will be of a VFR design except for an anhydrous NH_3 storage tank, which will be of a horizontal pressurized design.

2.7. (E.U. 007) Truck Rack Loadout Product and Flare

A truck loading rack will be used to load ethanol and ethanol blends from the product storage tank to trucks. The maximum truck loading rate will be 600 gal per minute (gpm) and 22,110,000 gallons per year (gal/yr) of ethanol blended with 900,000 gal/yr of gasoline (total throughput rate of 23,010,000 gal/yr). During ethanol truck loadout, ethanol vapors will be generated. The vapors are sent to the truck loading rack flare for destruction. The loading rack and the flare will be permitted to operate up to 3,120 hours per year (hr/yr). The product loadout flare will have a rated capacity of 9.8 mmBtu/hr to control VOC vapors displaced from the trucks during the loading of denatured ethanol product.

2.8. (E.U.008) Miscellaneous Dry Materials Storage Silos

The facility will include equipment and silos for the handling and storage of dry materials. The materials stored in these silos include lime for the DSIS and wastewater treatment plant and limestone related to the biomass boiler (BFB boiler, if used). These materials will be stored in silos, each of which will be equipped with fabric filters to control emissions during material handling.

2.9. (E.U.009) Emergency Generators

Two propane or ULSD-fueled emergency generators, each rated at 2,000 kilowatts (kW), will be installed to provide backup electrical power in the event of a power outage at the facility. Each generator will be limited to 500 hr/yr of operation during emergencies and 100 hr/yr for maintenance and testing.

2.10. (E.U.010) Emergency Fire Pump

A propane or ULSD-fueled 600 horsepower (hp) diesel fire pump will also be installed to provide firewater during power outages. This engine will be limited to 500 hr/yr of operation during emergencies and 100 hr/yr for maintenance and testing.

2.11. (E.U.011) Facility-wide Fugitive VOC Equipment Leaks

Fugitive VOC emissions are grouped for the entire process and will be minimized by implementation of a monthly leak detection and repair (LDAR) monitoring program.

2.12. Miscellaneous Operations

The applicant has also proposed the construction of a gas station facility to dispense ethanol and gasoline products and a dry ice (frozen CO_2) facility to utilize the CO_2 generated during the ethanol production process as its feedstock. These facilities are **not** addressed by this permitting action.

2.13. Project Emissions

Tabulations of project emissions are given and discussed in conjunction with major source review applicability in Sections 3.3, 3.4 and 3.5 below.

3. APPLICABLE REGULATIONS

3.1. State Regulations

This project is subject to the applicable environmental laws specified in Chapter 403 of the Florida Statutes (F.S.). The F.S. authorize the Department of Environmental Protection (Department) to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.).

This project is subject to the applicable rules and regulations defined in the following Chapters of the F.A.C. and summarized in Table 2.

Table 2 - Applicable Rules from the F.A.C.

F.A.C. Rule	Description
62-4	Permits
62-204	Air Pollution Control – General Provisions
62-210	Stationary Sources of Air Pollution – General Requirements
62-212	Stationary Sources – Preconstruction Review
62-213	Operation Permits for Major Sources (Title V) of Air Pollution
62-214	Requirements for Sources Subject to the Federal (Title IV) Acid Rain Program
62-296	Stationary Sources – Emission Standards
62-297	Stationary Sources – Emissions Monitoring

3.2. Federal Regulations

The U.S. Environmental Protection Agency (EPA) establishes air quality regulations in 40 CFR Part 60 that identifies New Source Performance Standards (NSPS) for a variety of industrial activities. 40 CFR Part 61 specifies National Emission Standards for Hazardous Air Pollutants (NESHAP). 40 CFR Part 63 specifies NESHAP provisions based on the Maximum Achievable Control Technology (MACT) for given source categories.

Federal regulations adopted by reference are given in Rule 62-204.800, F.A.C. State regulations approved by EPA are given in 40 CFR Part 52, Subpart K – Florida, also known as the State Implementation Plan (SIP) for Florida.

3.3. PSD Major Stationary Source Applicability Determination

The Department regulates major stationary sources in accordance with Florida's PSD program pursuant to Rule 62-212.400, F.A.C. PSD preconstruction review is required in areas that are currently in attainment with the state and federal Ambient Air Quality Standards (AAQS) or areas designated as "unclassifiable" for these regulated pollutants.

As defined in Rule 62-210.200(189),F .A.C., a facility is considered a "major stationary source" if it emits or has the potential to emit (PTE) 5 tons per year (TPY), 250 TPY or more of any PSD pollutant, or 100 TPY or more of any PSD pollutant and the facility belongs to one of the 28 listed PSD major facility categories. The planned SRF facility is a major stationary source because it is: *"A chemical processing plant which emits, or has the PTE, 100 TPY or more of any PSD pollutant."* According to EPA rules at 40 CFR 52.21(b)(1.)(iii)(*t*) (and most other state regulations), *"the term chemical processing plant shall not include ethanol production facilities that produce ethanol by natural fermentation included in NAICS codes 325193 or 312140"*. Thus EPA regulations would consider SRF to be a major stationary source if it emits or has the potential to emit 250 TPY or more of any PSD pollutant.

PSD pollutants include: CO; NO_X; SO_2; PM; PM_{10}; VOC; Pb; Fluorides (F); SAM; total reduced sulfur (TRS), including H_2S; municipal waste combustor (MWC) organics measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans (D/F); MWC metals measured as PM; MWC acid gases measured as SO_2 and hydrogen chloride (HCl); and Hg.

For major stationary sources, PSD applicability is based on emissions thresholds known as the significant emission rates (SER) as defined in Rule 62-210.200, (Definitions) F.A.C. Emissions of PSD pollutants from the project exceeding these SER are considered "significant" and BACT must be employed to minimize emissions of each PSD pollutant. Although a facility may be "major" for only one PSD pollutant, a project must include BACT controls for any PSD pollutant that exceeds the corresponding SER given in Table 3.

Table 3 – List of SER by PSD-Pollutant [1]

Pollutant	SER (TPY)	Pollutant	SER (TPY)
CO	100	NO_X	40
PM/PM_{10} [2]	25/15	Ozone (VOC) [3]	40
Ozone (NO_X) [3]	40	SAM	7
SO_2	40	F	3
Pb	0.6	TRS	10
H_2S	10	Hg	0.1

1. Excluding those defined exclusively for MWC and MSW landfills.
2. PM with a diameter less than 2.5 micrometers ($PM_{2.5}$) is also a PSD pollutant, but an SER has not yet been defined in the Department's rules. It is regulated by its precursors and surrogates (e.g. PM/PM_{10} NH_3, SO_2, NO_X).
3. Ozone (O_3) is regulated by its precursors (VOC and NO_X).

Table 4 summarizes the applicant's estimates of key PSD pollutants from the proposed SRF project. The project will result in emissions of NO_X, CO, PM, PM_{10},$PM_{2.5}$, SO_2, SAM, VOC, Pb and Hg. It is clear that the greatest emission source by far is the boiler, which accounts for more than 95% of all PSD-pollutants to be emitted from the SRF facility.

Table 4 – Applicant's Revised Estimated PTE of Key PSD Pollutants (in TPY) for the SER Facility[1]

Operation/EU	CO	NO_X	PM/PM_{10} [2]	$PM_{2.5}$ [2]	SO_2	SAM	VOC	Hg[4]	Pb
Biomass Material Handling (001)			21.7/5.2	1.6					
Boiler (002)	205.0	205.0	30.7/30.7	26.6	180.4	7.9	20.5	0.022	0.19
Three Cooling Towers (003)			0.35/0.17	0.17			0		
Ethanol Production (004)							42.3		
Bioreactors, Biogas Flare (005)	0.21	0.35	0.13	0.13	0.91	~0.1	5.0		
Storage Tanks (006)							10.6		
Product Loadout and Flare (007)	5.64	1.04	0.052	0.052	0.009		2.1		
Miscellaneous Storage Silos (008)			0.036	0.036			0		
Two Emergency Generators (009)	0.86	15.9	0.077	0.077	0.017		0.32		
Emergency Fire Pump Engine (010)	0.86	0.89	0.049	0.049	0.002		0.10		
Fugitive Equipment Leaks (011)							6.52		
Totals	212.6	223.25	3.1/36.4	28.7	181.3	8.0	87.4	0.022	0.19
SER	100	40	25/15	(10) [3]	40	7	40	0.1	0.6
PSD Applies? (Yes/No)	Yes	Yes	Yes	No [3]	Yes	Yes	Yes	No	No

1. Per RAI responses and updated submittals as of 10/12/2010.
2. Estimates based on filterable (front-half sampling train) material and do not include condensable (back-half) material.
3. PSD would apply based on the federal SER (reference 40 CFR 52.21) of 10 TPY for $PM_{2.5}$ or 40 TPY of its surrogates (NO_X or SO_2). PSD does not apply per the present Department rules incorporated into the federal rules at 40 CFR 52, Subpart K.
4. Uncontrolled estimate equals 44 pounds Hg per year (lb/yr). Subsequently (9/15/2010) applicant estimated 3.3 lb Hg/yr.

In summary, the SRF project will emit at least 100 TPY of at least one PSD pollutant (though less than 250 TPY of each and every PSD pollutant): Emissions of the following PSD air pollutants as proposed by the applicant will exceed their respective SER: NO_X,PM/ PM_{10}, SO_2, CO, SAM,an d VOC. Therefore, the SRF project will be subject to the Department's PSD rules including PSD ambient air modeling and a requirement for a best available control technology (BACT) determination for the cited pollutants. $PM_{2.5}$ will be addressed by the BACT evaluations for its precursors and surrogates [NO_X, SO_2, VOC and NH_3 slip].

3.4. Major Source of Air Pollution (Title V Source) Determination

As defined in Rule 62-210.200(188), F.A.C., a Title V source is an emissions unit or group of emissions units that directly emits, or has a PTE of, 100 TPY or more of any regulated air pollutant.

The Major (Title V) Source of Air Pollution definition also includes, any emissions unit or group of emissions units that (except for radionuclides) emits or has the PTE of, in the aggregate, 10 tons TPY or more of any one HAP, 25 TPY or more of any combination of HAP, or any lesser quantity of a HAP as established through EPA rulemaking. Specific HAP are defined/listed in Rule 62-210.200(155), F.A.C.

The emissions estimates given in Table 4 are sufficient to conclude that the SRF facility will be a Title V source based on emissions of regulated air pollutants regardless of HAP emissions.

3.5. HAP Major Source Determination

As defined in 40 CFR 63, Subpart A, adopted and referenced in Rule 62-204.800(11)(d)1, F.A.C.,a nd per Rule 62-210.200(188 – Major Source of Air Pollution), F.A.C., a major source of HAP means any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the PTE of, considering controls, in the aggregate, 10 TPY or more of any HAP or 25 TPY or more of any combination of HAP, unless the Administrator establishes a lesser quantity, or in the case of radionuclides, different criteria from those specified in this sentence. See Subpart A .

Pursuant to Rule 62-210.200 (188), F.A.C., if a facility is a major source of HAP it will also be a Title V source. Table 5 is a summary of the applicant's estimate of HAP from the key emission categories at the SRF facility.

Table 5 – Applicant's Estimated PTE of HAP from the SRF Project in TPY

Pollutant	HCl	HF	Cl_2	Key Metal HAP [1]	Key Organic HAP [2,3]	Other HAP	Total
Boiler	0.91	0.03	2.66	0.99	13.87	0.31	18.77
Ethanol Process					3.46		3.46
Other Sources						0.75 [4]	0.75
Total	0.91	0.03	2.66	0.99	17.33	1.06	22.98

1. Key metal HAP for the boiler consist of chromium (Cr), lead (Pb), manganese (Mn) and nickel (Ni).
2. Key organic HAP for the boiler consist of acetaldenhyde (C_2H_4O), acrolein (C_3H_4O), benzene (C_6H_6), Bis(2-ethylhexyl) phthalate ($C_{24}H_{38}O_4$), 1,4-Dichlorobenzene ($C_6H_4Cl_2$), formaldehyde (CH_2O), hexane (C_6H_{14}), styrene (C_8H_8), toluene (C_7H_8), polycyclic aromatic hydrocarbon/polycyclic organic matter (PAH/POM).
3. Key Organic HAP for the ethanol process consists of: acetaldehyde (C_2H_4O), acrolein (C_3H_4O), formaldehyde (CH_2O) and methanol (CH_4O).
4. This includes all HAP for all other sources such as fugitive emissions from equipment leaks and tanks.

The main source of HAP is the boiler. The greatest single HAP from the biomass boiler is formaldehyde at 4.26 TPY, followed by benzene at 3.72 TPY, chlorine (molecular Cl_2 – not to be confused with chlorides) at 2.66 TPY, acrolein at 2.4 TPY and styrene at 1.13 TPY. The other meaningful HAP emission (> 1 TPY) is acetaldehyde from the ethanol process at 3.17 TPY.

According to the applicant's estimate, the facility (boiler and other processes) does not constitute a major source. However, the projected emissions of HCl and hydrogen fluoride (HF) from the boiler may have been underestimated by approximately an order of magnitude. Thus, without additional control beyond that listed in the application, the Department does not have reasonable assurance that the facility is not a major HAP source. The reasons for the lack of reasonable assurance are:

- All woody and non-woody biomass project applications with DSIS and ESP or baghouse received to-date by the Department have projected emissions on the order of 10 to 20 TPY of HCl plus HF combined;
- PPC Air Pollution Control Systems of Houston (the DSIS and ESP vendor that provided a quote to SRF) guaranteed 94 and then 13.7 TPY of HCl emissions;
- In developing the pre-control emission factors, the applicant selected the geometric mean (approximately equal to 60% of the arithmetic mean) of the results of HCl tests conducted at sugar mills as the pre-control level rather than the arithmetic mean;
- The applicant's pre-control emission factor for HCl emissions from sorghum bagasse was developed based on emission tests conducted at existing facilities using low chloride (washed) sugar cane bagasse but not the field residue;
- Sorghum requires substantial potassium (K) fertilizer to thrive.[1] Most K is actually delivered as potassium chloride (KCl) and it has been demonstrated that sorghum crops are more productive when chlorides are added; [2]

1 http://edis.ifas.ufl.edu/ag343 UF/IFAS Publication 343. July 2010.
2 www.ipni.net/ppiweb/bcrops.nsf/$webindex/F6F022EB98A80C17852569970067E01C/$file/00-4p10.pdf Better Crops/Volume 84, No. 4. 2000.

- Sorghum leaf tissue samples tested by IFAS[3] contained approximately five times as much chloride (0.53 to 0.90%) compared with sorghum bagasse washed with deionized water (0.15%), which in-turn, contained significantly more chloride than reported in the literature[4] for sugar cane bagasse (0.03%) or by the applicant;
- In contrast to sugar operations, SRF will burn bagasse and sorghum harvest residue in the boiler (releasing harvest residue HCl in the furnace) rather than in the fields (where such burning would release HCl directly into the air); and
- If emissions of HCl plus HF from SRF are only 3 TPY (much less than guaranteed by PPC) the facility will emit 25 TPY of HAP.

If the facility emissions equal or exceed the 10 or 25 TPY HAP thresholds, then the ethanol process will be subject to a number of promulgated NESHAP including 40 CFR 63, Subpart FFFF – NESHAP: Miscellaneous Organic Chemical Manufacturing, adopted and incorporated as Rule 62-204.800(11)(d)63., F.A.C. See Subpart FFFF .

If the facility emissions equal or exceed the 10 or 25 TPY HAP thresholds, the boiler will be subject to a case-by-case MACT as defined in and in accordance with 40 C.F.R. Part 63, Subpart B, adopted and incorporated by reference in Rules 62-210.200(191) and 62-204.800(11)(d)2., F.A.C. See Subpart B .

Application of Subparts B and FFFF in combination with a BACT determination would require additional control equipment such that the project would likely emit less than the 10 and 25 TPY HAP thresholds (even if HCl emissions are 9.1 rather than 0.91 TPY). For example, installation of catalysts to control CO, VOC or NO_X would as a co-benefit reduce all organic HAP sufficiently to make the project a minor source even if HCl emissions are adjusted upwards by an order of magnitude.

If such control is requested by the applicant or required by the Department's BACT determination, then the project would not be a major source of HAP and it would not be necessary to require compliance with Subpart FFFF or to conduct a Subpart B MACT determination.

The Department will include sufficient conditions in the permit to provide reasonable assurance that the project will not be a major source of HAP.

3.6. Review of other Key Regulatory Provisions for Applicability to Project

Following is a summary of the applicability of key regulatory provisions to the SRF project.

Chapter 62-4, F.A.C. www.dep.state.fl.us/air/rules/fac/62-4.pdf

Rule 62-4.070(1), F.A.C., Standards for Issuing or Denying Permits; Issuance; Denial.

This rule applies to all permitting decisions:

- A permit shall be issued to the applicant upon such conditions as the Department may direct, only if the applicant affirmatively provides the Department with reasonable assurance based on plans, test results, installation of pollution control equipment, or other information, that the construction, expansion, modification, operation, or activity of the installation will not discharge, emit, or cause pollution in contravention of Department standards or rules.

Chapter 62-17, F.A.C. www.dep.state.fl.us/siting/files/rules_statutes/pps_rule.pdf

- The SRF project is not subject to certification pursuant to the power plant siting provisions of this rule because it will produce less than 75 MW of power.

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3 Laboratory Analysis. Sweet Sorghum Biomass Component Study. UF/IFAS.

4 Tilman, D.A. et al. Chlorine in solid fuels fired in pulverized fuel boilers – sources, forms, reactions, and consequences: A literature review. Energy and Fuels 23:3379-3391.

Chapter 62-204, F.A.C. www.dep.state.fl.us/air/rules/fac/62-204.pdf

Rule 62-204.220(1), F.A.C., Ambient Air Quality Protection.

This rule applies to all air permitting decisions.

- The Department shall not issue an air permit authorizing a person to build, erect, construct, or implant any new emissions unit; operate, modify, or rebuild any existing emissions unit; or by any other means release or take action which would result in the release of an air pollutant into the atmosphere which would cause or contribute to a violation of an ambient air quality standard established under Rule 62-204.240, F.A.C.

Rule 62-204.240, F.A.C., Ambient Air Quality Standards.

This rule applies to all air permitting decisions.

- Refer to list of pollutants and ambient air quality standards provided therein and discussed in the Ambient Air Quality Section of this evaluation.

Rule 62-204.800(8), F.A.C., 40 CFR 60, NSPS.

The following provisions incorporated into Rule 62-204.800(8), F.A.C. adopted from 40 CFR 60 and incorporated into this rule apply to this project:

- 40 CFR 60, Subpart A – General Provisions which regulates all EU that are subject to a NSPS standard and, in particular, flare pilot flames (EU 005 and 007);
- 40 CFR 60, Subpart Db – Industrial-Commercial-Institutional Steam Generating Units (EU 002);
- 40 CFR 60, Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 (EU 006);
- 40 CFR 60, Subpart IIII – Stationary Compression Ignition Internal Combustion Engines (ICE) (EU 009 and 010); and
- 40 CFR 60,Su bpart VVa – VOC Equipment Leaks from SOCMI Processes (EU 002, 003,004, 005, 006, 007 and 011).

SRF requested a federally enforceable permit limiting the boiler (EU 002) to combusting a fuel feed stream containing less than 30% municipal solid waste (MSW), including yard waste, as measured on a calendar quarter basis to qualify as a cofired combustor. Thus, except for a notification of exemption and quarterly MSW recordkeeping, the SRF project is exempt from the following rule:

- 40 CFR 60,Su bpart Eb – Large Municipal Solid Waste Combustors for Which Construction is Commenced After September 20, 1984 or for Which Modification or Reconstruction is Commenced After June 19, 1996.

By letter dated March 26, 2009, EPA provided a determination to the Department that the following NSPS do not apply to the Highlands Ethanol project (therefore by extension to the present project) that process ethanol produced by biological processes:

- 40 CFR 60 Subpart NNN – VOC Emissions from SOCMI Distillation Operations; and
- 40 CFR 60 Subpart RRR – VOC Emissions from SOCMI Reactor Processes.

Rule 62-204.800(11), F.A.C., 40 CFR 63, NESHAP.

The following provisions incorporated into Rule 62-204.800(11), F.A.C. adopted from 40 CFR 63 and incorporated into this rule apply to this project:

- 40 CFR 63, Subpart A – General Provisions (to the extent explicitly identified within each applicable 40 CFR 63 standard); and
- 40 CFR 63, Subpart ZZZZ – Stationary Reciprocating Internal Combustion Engines (RICE). This subpart requires all affected area source units to meet the applicable emission standards of 40 CFR 60, Subpart IIII. 40 CFR 63, Subpart A is explicitly excluded when applying this standard.

On June 4, 2010 EPA published notice in the Federal Register on the following proposed rule, which when finalized (and adopted by the Department), potentially applies to this project:

- 40 CFR 63, Subpart JJJJJ – NESHAP for Industrial, Commercial, and Institutional Boilers Area Sources.

The following provisions incorporated into Rule 62-204.800(11), F.A.C. adopted from 40 CFR 63 and incorporated into this rule do not apply to this project because after Department-required controls it is not a major source of HAP:

- 40 CFR 63, Subpart B – Requirements for Control Technology Determinations for Major Sources in Accordance With Clean Air Act (CAA) Sections, Sections 112(g) and 112(j);
- 40 CFR 63, Subpart DDDDD – Industrial, Commercial, and Institutional Boilers and Process Heaters (proposed on June 4, 2010); and
- 40 CFR 63, Subpart FFFF – Miscellaneous Organic Chemical Manufacturing (and by reference Subparts H , Q, SS, TT, UU, WW, and GGG).

Chapter 62-210, F.A.C. www.dep.state.fl.us/air/rules/fac/62-210.pdf

62-210.200, F.A.C., Definitions.

- The project is a Title V or "Major Source" of air pollution because the PTE of at least one regulated pollutant will exceed 100 TPY.
- The project is not a major source of HAP because it will not emit or have PTE of 10 TPY or more of any one HAP or 25 TPY or more of any combination of HAP.
- The project is classified as a "Major Stationary Source" (PSD-source) because it emits 100 TPY or more of a PSD pollutant and is one of the 28 facility categories listed in the definition with the PSD applicability threshold of 100 TPY.

Rule 62-210.300, F.A.C., Permits Required.

- Unless exempted, the owner or operator of any facility or emissions unit which emits or can reasonably be expected to emit any air pollutant shall obtain appropriate authorization (i.e. a permit) from the Department prior to undertaking any activity at the facility or emissions unit for which such authorization is required.

Rule 62-210.350, F.A.C. Public Notice and Comment.

- A notice of proposed agency action on permit application, where the proposed agency action is to issue the permit, shall be published by any applicant.
- The rule details additional public notice requirements for emissions units subject to PSD. Examples include: the location and nature of the project; whether BACT has been determined; PSD increment consumption; and notification to the public of the opportunity to submit comments or request a public hearing (meeting).

Rule 62-210.700, F.A.C., Excess Emissions.

This rule applies to all air permitting decisions. Only the key provisions potentially affecting this project are listed.

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

Chapter 62-212, F.A.C. www.dep.state.fl.us/air/rules/fac/62-212.pdf

Rule 62-212.300, F.A.C., General Preconstruction Review Requirements.

- This rule generally applies to the construction or modification of air pollutant emitting facilities in those parts of the state in which the state ambient air quality standards are being met.

Rule 62-212.400, F.A.C., PSD.

- The rule applies because the project is a major stationary (PSD) source.

Chapter 62-213, F.A.C. www.dep.state.fl.us/air/rules/fac/62-213.pdf

- Because the facility is a Title V source, the applicant will be required to apply for and obtain a Title V operation permit in the future.

Chapter 62-214, F.A.C. www.dep.state.fl.us/air/rules/fac/62-214.pdf

- The applicant asserts that the planned facility is a cogeneration plant and not subject to the Acid Rain Program (ARP) because it will provide 219,000 MW-hours or less of actual electric output on an annual basis to any utility power distribution system for sale on a gross basis. However, if in any three calendar year period, such unit sells to a utility power distribution system an annual average of more than one-third of its potential electrical output capacity and more than 219,000 MW-hours of actual electric output, that unit shall be an affected unit, subject to the requirements of the ARP.

Chapter 62-296, F.A.C. www.dep.state.fl.us/air/rules/fac/62-296.pdf

Rule 62-296.320, F.A.C., General Pollutant Emission Limitation Standards.

- This rule prohibits the discharge of air pollutants which cause or contribute to an objectionable odor;
- This rule specifies a visible emissions standard of 20 percent (%) opacity; and
- The rule prohibits emissions of unconfined PM provisions without taking reasonable precautions to prevent such emissions.

Rules 62-296.401, F.A.C., Incinerators

- The facility will combust a fuel feed stream containing less than 30% MSW as measured on a calendar quarter basis to qualify as a cofired combustor per 40 CFR 60, Subpart Eb. The Department's definition of "incinerator" at Rule 62-210.200(160), F.A.C. is "a combustion apparatus designed for the ignition and burning of solid, semi-solid, liquid or gaseous combustible wastes". Although the furnace is not primarily designed to burn wastes, the term incinerator arguably applies as well as this incinerator rule.

Rule 62-296.416, F.A.C., Waste-to-Energy (WTE) Facilities

- This rule does not apply because per Rule 62-210.200(327), F.A.C., the term "WTE facility" does not include facilities that primarily burn fuels other than solid waste, even if the facility also burns some solid waste as a fuel supplement. The term also does not include facilities that burn vegetative, agricultural, or silvicultural wastes, bagasse, clean dry wood, methane or other landfill gas, wood fuel derived from construction or demolition debris, or waste tires, alone or in combination with fossil fuel. Because of its status (by a federally enforceable permit condition) as a cofired facility in accordance with 40 CFR 60, Subpart Eb, the facility will burn at least 70% fuels "other than solid waste".

Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 mmBtu/hr Heat Input

- This rule applies only to the extent that fossil fuel is burned in the boiler. The fossil fuel heat input capability of the boiler will be less than 250 mmBtu/hr. This provision requires compliance with applicable NSPS requirements for visible emissions, PM, NO_X and SO_2 (e.g., NSPS Subpart Db requirements).

Rule 62-296.410, F.A.C., Carbonaceous Fuel Burning Equipment.

- Sorghum is carbonaceous fuel when directly combusted and this rule requires that the carbonaceous component of fuel combustion comply with a PM standard of 0.2 lb/mmBtu. Visible emissions are limited to 30% opacity except that 40% opacity is permissible for not more than 2 minutes in any hour.

Rule 62-296.470, F.A.C., Implementation of Federal Clean Air Interstate Rule (CAIR).

- The SRF facility is not subject to CAIR but could become subject to CAIR based on final promulgation of a CAIR replacement rule by EPA or for reasons similar to those outlined in the ARP applicability discussion above.

4. BACT REVIEW

BACT determinations are required for the pollutants that are subject to PSD review, including CO, NO_X, PM/PM_{10}, SO_2, SAM and VOC. These determinations are provided in the following sections and are organized and presented by process step. A BACT determination for $PM_{2.5}$ is not required primarily because the Department is not yet required to submit an update of its SIP for incorporation into 40 CFR 52, Subpart K and the Department has not yet adopted a SER for $PM_{2.5}$ and identified it as a PSD-pollutant.

Even without a SIP requirement and without approved test methods or accounting requirements,t he Department nevertheless relies on precursors and surrogates to minimize direct emissions and subsequent formation of $PM_{2.5}$ per the rationale given below.

On September 16, 1997, EPA revised the NAAQS for particulate matter, which includes a new NAAQS for $PM_{2.5}$. Florida implemented an ambient monitoring program for $PM_{2.5}$. As EPA mentioned in its guidance dated October 23, 1997, there are significant technical difficulties with respect to $PM_{2.5}$ monitoring, emissions estimation and modeling.

This guidance recommended the use of PM_{10} as.a surrogate for $PM_{2.5}$ in meeting new source review (NSR) requirements under the CAA, including the permit programs for PSD. Meeting these measures in the interim will serve as a surrogate approach for reducing $PM_{2.5}$ emissions and protecting air quality. Florida is in the process of revising its SIP to address the new $PM_{2.5}$, NAAQS, PSD SER and ambient air quality impact thresholds for modeling analyses as required by EPA for approved states by 2011. Until state regulations support PSD preconstruction review for $PM_{2.5}$ emissions, the Department will rely on PM_{10} emission limits and $PM_{2.5}$ precursor limits (e.g., SAM, SO_2, VOC, NH_3, and NO_X). This approach is more robust than the EPA guidance memoranda.

Rule 62-210.200, F.A.C. defines "BACT" as:

An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account:

1. *Energy, environmental and economic impacts, and other costs;*
2. *All scientific, engineering, and technical material and other information available to the Department; and*
3. *The emission limiting standards or BACT determinations of Florida and any other state;*

determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.

If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of an emissions unit or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice or operation.

Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results.

In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60, 61, and 63.

4.1. BACT Review for Roadway Emissions and Biomass Handling (EU 001)

$PM/PM_{10}/PM_{2.5}$ Emissions

Discussion. $PM/PM_{10}/PM_{2.5}$ emissions is the only pollution of concern from EU 001. Refer to the description of EU 001 in Section 2.1 above. The trucks that will be used to deliver sweet sorghum feedstock and supplemental boiler fuel biomass along with the biomass handling and processing itself will generate fugitive dust.

Figure 10 below is a diagram of the bagasse and supplemental boiler biomass feed system. Because of the biomass high moisture content, fugitive emissions are expected to be minimal from this part of the process. The boiler biomass (bagasse and supplemental) will be stored in piles located in the biomass yard in the southeastern quadrant of the SRF site as shown in Figure 5. When required, the material will be reclaimed using a mobile front wheel loader, and placed onto the live reclaim area from which it will be conveyed to a scalping screen or shaker screen and then transported to the boiler feed bin and fed into the biomass boiler.

Applicant's Proposal. SRF proposes to utilize reasonable precautions and a best management practices (BMP) plan approved by the Department for controlling fugitive dust emissions from this emission unit. These precautions include the following: enclosing conveyors (e.g. that the conveyance belt for the biomass is totally enclosed from above thus preventing wind from causing fugitive dust emissions with the bottom of conveyance belt accessible for maintenance and repairs) and material drop 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 access roads; sweeping and watering of paved surfaces as needed to remove dust; and utilizing water sprays on ash material from the boiler, as necessary.

Department's Review. The Department accepts the procedures described by the applicant as BACT for sweet sorghum feedstock and supplemental biomass receiving and handling, with the addition of wetting the gravel areas, as necessary, during dry conditions. In addition, where practical, dust collectors must be installed at drop and transfer points in the biomass handling systems and the paved areas must be vacuumed swept at least weekly.

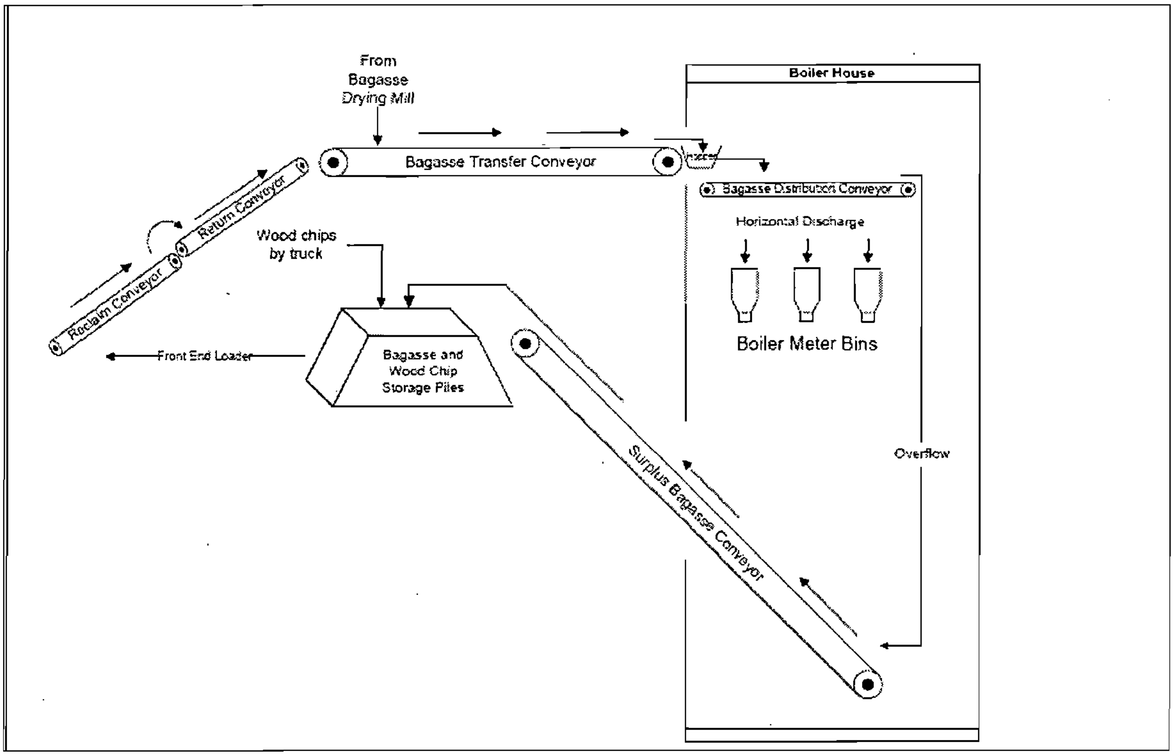


Figure 10 - Boiler Biomass Feed System.

4.2. BACT Review for Biomass-Fueled Boiler (EU 002)

Basic BFB or stoker boiler characteristics and controls to the extent proposed or known are provided in Section 2.2 above.

NO_X Emissions

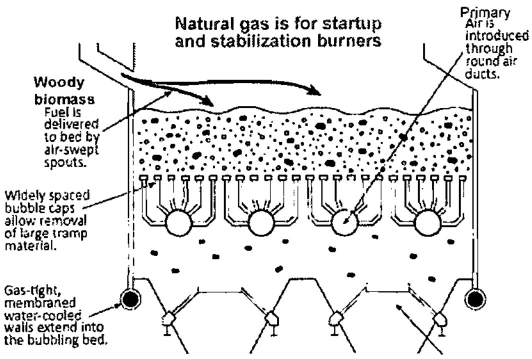
NO_X Formation and Primary Control.

NO_X formation in the boiler may occur by three different mechanisms: fuel NO_X is formed from nitrogen compounds contained in fuel (fuel nitrogen); thermal NO_X is formed from molecular or atomic nitrogen (N_2) and oxygen (O_2) present in combustion air; and prompt NO_X is formed in the proximity of the flame front as intermediate combustion products.

BFB Boiler Principles. Details of the bed portion of a Babcock and Wilcox (B&W) BFB are provided in Figure 11. Figure 12 is an internal diagram for the typical furnace configuration of a HYBEX BFB biomass boiler such as offered by METSO Power.

BFB boiler beds are typically maintained at temperatures on the order of 1,350 to 1,700 degrees Fahrenheit (°F). This minimizes thermal NO_X formation but not fuel NO_X formation. The furnace temperature is higher above the fluidized bed where the OFA is introduced but not high enough to form thermal NO_X.

Combustion within the BFB bed occurs under reducing (O_2 starved) conditions provided by the primary air. The fuel in the bed undergoes drying, and partial combustion. Following is the Department's theoretical and simplified explanation of the manner by which combustion proceeds, focusing on the formation and destruction of NO_X. The process involves literally hundreds of steps or reactions expressed as the simplified and unbalanced equations (Eq.) below.



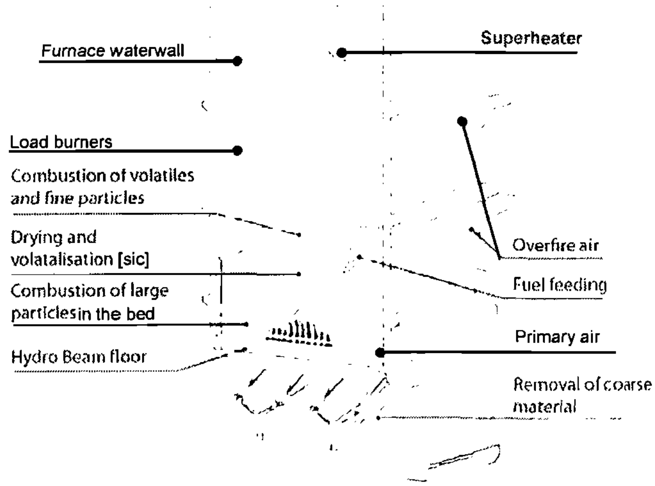


Figure 11 – Bed Description for B&W BFB Boiler   Figure 12 – Typical METSO HYBEX BFB Boiler

Equation 1. The fuel immediately above and within the bed is heated and pyrolyzed releasing hydrocarbon radicals (CHi*). These, in turn, catalytically or otherwise react with NO to form hydrogen cyanide (HCN) according to:

$$CHi^* + NO \rightarrow HCN + ...$$ Eq. 1

Where:

$i = 1, 2, 3$

Equation 2. HCN in turn destroys more NO_X in the reducing environment according to:

$$HCN + NO \rightarrow N_2 + CO + CO_2 + H_2O + ...$$ Eq. 2

Equation 3. Ammonia-like radicals (NHi*) are also released during pyrolysis. Under reducing conditions these radicals destroy NO according to:

$$NHi^* + NO \rightarrow N_2 + ...$$ Eq. 3

This mechanism suppresses formation of NO by the pyrolyzed fuel nitrogen and recruits that nitrogen to combat NO_X in reactions that at first glance look much like SCR or selective non-catalytic reduction (SNCR) discussed further below.

Reactions 2 and 3 can be catalytically enhanced based on the presence of various species within such an environment. Also, they can be accelerated by attaining a relatively high temperature within the reducing atmosphere but well below that which would promote thermal NO_X formation. Other reactions involving CO or hydrogen (H_2) also destroy NO_X in this reducing atmosphere and can be to varying degrees catalytically enhanced. Additional volatile and char combustion occurs in the higher temperature free board region above the bed. CharC denotes char carbon and CharN denotes char nitrogen.

Equation 4 and 5. Under the reducing conditions, even the char can assist on NO_X destruction as follows:

$$CharC + NO \rightarrow N_2 + CO + CO_2 + ...$$ Eq. 4

$$CharN + O_2 \rightarrow N_2 + O_2 + ...$$ Eq. 5

Eventually the NO_X destruction reactions will proceed much more slowly and some of the remaining fuel nitrogen forms additional NO_X.

Equations 6, 7, 8 and 9. In the presence of the progressively oxidizing environment effected by the two OFA levels, NO_X formation rather than destruction predominates.

$$NH_3 + O_2 \rightarrow NO + ... \qquad \text{Eq. 6}$$

$$HCN + O_2 \rightarrow NO + ... \qquad \text{Eq. 7}$$

$$CharC + O_2 \rightarrow NO + ... \qquad \text{Eq. 8}$$

$$CharN + O_2 \rightarrow NO + ... \qquad \text{Eq. 9}$$

The management of NO_X formation and destruction involves promotion of Eq. 1 through 5 to form N_2 before the inevitable and progressive addition of OFA causes Eq.6 through 9 to dominate. This can be accomplished to the greatest degree by delaying and then adding the OFA in stages.

It was previously mentioned that peak flame temperatures will increase when lower moisture content biomass fuels are combusted and during low load boiler operations. During these periods, flue gas recirculation (FGR) will be employed to lower the peak flame temperatures thus avoiding the tendency to form thermal NO_X.

The NO_X formation and destruction considerations must also be coupled with CO, PM and VOC management in a combined strategy that constitutes GCP.

Stoker Principles. Modern stoker units for biomass firing are normally mechanical rotating grates or water/air-cooled vibrating grates depending on the fuel moisture content. Fuel is typically introduced into the boiler through multiple fuel chutes. Preheated combustion air is supplied under the grate as well as above via an OFA system. Depending on the fuel moisture content, the combustion air is pre-heated to 350 to 650 °F. The furnace temperature is greater than experienced in a BFB boiler and thus it is possible to form both fuel and thermal NO_X.

Due to high shaft velocities in the lower furnace and the manner by which fuel is spread or thrown onto the grate, some unburned fuel (carbonaceous ash) is carried out of the furnace. In order to recover the energy value of this carbonaceous ash, stoker-fired boilers typically include a re-injection system that recycles the carbonaceous ash back into the furnace.

Because of the hot particle carryover and possible effects on fabric filters, ESP technology is usually incorporated into wood biomass stoker technology projects. A mechanical dust collector is also typically installed to prevent heavy (possibly abrasive) particle carryover from reaching the ESP.

Figure 13 includes a diagram of a Detroit Hydro-Grate and a typical stoker-based process schematic. Sized fuel is metered to a series of distribution devices which spread it uniformly over the stoker grate surface. Fine particles of fuel are rapidly burned in suspension assisted by OFA. Coarser, heavier fuel particles are spread evenly on the grate forming a thin, fast-burning fuel bed.

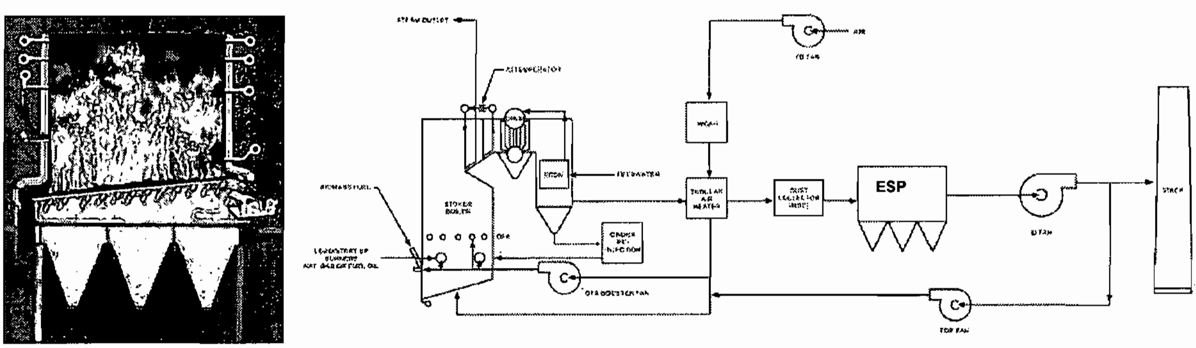


Figure 13 – Detroit Hydro-Grate and Typical Stoker-based Process Schematic

The Detroit Hydro-Grate stoker includes an automatic ash discharge system and water-cooled grates. The higher combustion air temperature needed to burn high moisture fuel can be maintained without damaging the grates.

Following are additional details and opinions provided by B&W when comparing the emission characteristics of a typical stoker furnace with a fluidized bed combustion (FBC) furnace and, more specifically, a BFB.[5]

[In a stoker boiler] "The combustion zone temperature is typically neither measured nor controlled and can range from 2,200 to over 3000 °F. The BFB bed temperature is both measured and controlled to an optimum temperature of approximately 1500 °F.

"Due to the improved combustion process previously described for a BFB, the uncontrolled (upstream of any post combustion air quality control systems) NO_X, CO and VOC emissions for a BFB are typically 10 to 25% less for a given biomass fuel than for a stoker." B&W further adds:

"The BFB emissions are also less susceptible to variations in fuel properties that are inherent with any biomass plant. Under normal steady state operating conditions, both the BFB and stoker can be operated reliably within permitted emission limits. However, normal day-to-day operations in a typical plant are anything but steady state. Fuel variability is a fact of life, even when a conscious effort is made in the fuel yard to keep the fuel homogeneous. The large mass of bed material in the BFB creates a "flywheel effect," which is better suited to minimize spikes in emissions due to any changes in fuel characteristics. Conversely, the relatively low fuel inventory on a grate will typically be much more susceptible to an upset and potential emissions spikes, under changing fuel conditions."

According to SRF, "the spreader stoker technology results in inherently higher uncontrolled NO_X emissions compared to the fluidized bed boiler".[6] The Department agrees with the stated B&W and SRF opinions for comparisons between BFB boilers and late 20th century stoker boiler. By incorporating modern developments in GCP or through add-on controls, a stoker can achieve similarly low emissions compared with a BFB boiler.

In response to the Department's aggressive NO_X requirement for the Hillsborough County Waste-to-Energy (WTE) Facility Unit 4 in 2006, Covanta and its affiliate (Martin GmbH) embarked on an effort to improve the profile of the Martin Grate stoker design by employing advanced GCP concepts. They call their designs low NO_X (LN™) and very low NO_X (VLN™) [7].

Basically, all of the NO_X formation and destruction phenomena described for the BFB boiler in Eq. 1 through 9 exist for the stoker to varying degrees. The technology, known as VLN™, employs combustion system design, which in addition to conventional primary and secondary air streams, also features a new internal stream of gas called "VLN™ gas," which is drawn from the combustor and re-injected into the furnace. The gas flow distribution between the primary and secondary air, as well as the VLN™ gas, is controlled to yield the optimal flue gas composition and furnace temperature profile to minimize NO_X formation and optimize combustion.

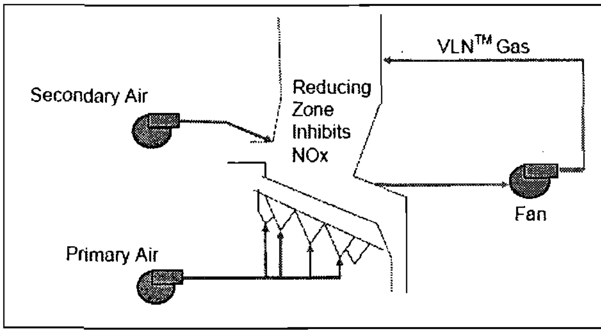
Figure 14 is a simplified diagram of the VLN™ process. Figure 15 demonstrates that operation of the VLN™ system reduces NO_X concentration by roughly half.

There are numerous other approaches which are marketed under names like Mobotec, EcoJet, EcoTube, Prizm, etc. that incorporate innovations such that emissions from stokers can be minimized by modern GCP and then achieve very low emissions with add-on controls. Given advances in GCP and add-on controls (discussed below) since the 1990s, the stoker emissions profile must be treated similarly to those of BFB boilers.

5 Brochure - Bubbling Fluidized Bed or Stoker — Which is the Right Choice for Your Renewable Energy Project?

6 Letter. SRF to FDEP. Southeast Renewable Fuels, LLC, Response to Letter dated August 6, 2010. www.dep.state.fl.us/Air/emission/bioenergy/southern_renewables/serf_add_info_082410.pdf. August 24, 2010.

7 Covanta and Martin GmbH. New Process for Achieving Very Low NO_X. Proceedings of the 17th Annual North American Waste-to-Energy Conference. May 2009.



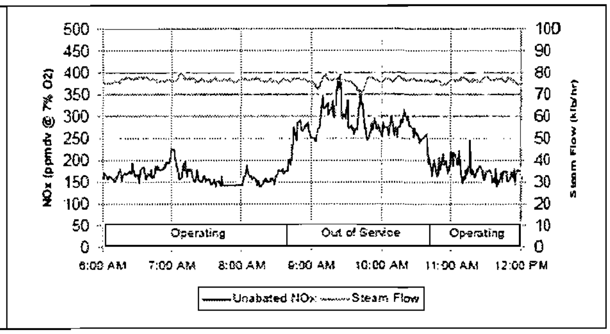


Figure 14 – Diagram of the VLN™ Process **Figure 15 – Operation with/without/with VLN™ System**

Add-on NO_X Control. Until recently, add-on controls NO_X were uncommon for biomass boilers. Initial add-on NO_X controls consisted of SNCR whereby NH_3 or urea is injected at a point in the process characterized by a suitable temperature window between about 1,500 and 1,900 °F depending on residence time, turbulence, oxygen content, and a number of other factors specific to the given gas stream. The reaction products are N_2 and water vapor (H_2O). SNCR destroys NO_X by a multi-step process as which is simplified in the equations below.

Equation 10. NH_3 reacts with available hydroxyl radicals (OH*) to form amine radicals (NH_2*) and water per the following theoretical equation:

$$NH_3 + OH^* \rightarrow NH_2^* + H_2O \qquad \text{Eq. 10}$$

Equation 11. Amine radicals combine with NO to form nitrogen and water as follows:

$$NH_2^* + NO \rightarrow N_2 + H_2O \qquad \text{Eq. 11}$$

Equation 12. The two steps are typically expressed as a single "global reaction".

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O \qquad \text{Eq. 12}$$

Similar simplified reactions describe the destruction of NO_2, which is present in much less concentrations than NO. One drawback with SNCR is that some of the NH_3 can be converted to NO_X and excessive NH_3 injection is occasionally required to effect good reduction. Excess NH_3 (called slip) can combine with chloride and sulfate species in the exhaust and cause visible emissions. Additionally good CO control is necessary when employing SNCR due to interference with the reaction as described.

Equation 13. CO competes with NH_3 for available OH radicals needed to effect Eq. 10.

$$CO + OH^* \rightarrow CO_2 + H^* \qquad \text{Eq. 13}$$

In the case of SCR technology, the NH_3 is injected in the presence of catalyst and at a lower temperature than encountered in the furnace. The reactions are more complete and efficient and NH_3 slip is minimized.

In most Florida coal-fueled power plants (e.g. Stanton Energy Center, Progress Energy Crystal River, St. John River Power Park, Tampa Electric Big Bend and others), the SCR unit is located in a dusty environment ahead of other pollution control equipment. Notwithstanding the severe atmosphere, NO_X reduction on the order of 90% is achieved at some of the most recent installations. According to EPA, there are online SCR systems on about 123 gigawatts (GW) of coal steam units.[8] The Department estimates that this equates to 300 coal-fueled units each of 400 MW capacity or nearly 5,000 SRF-sized (30 MW) units.

[8] Electronic Communication. William Maxwell, EPA Energy Strategies Group. SCR Count on Coal Utilities.

Refer to Figure 16 below that describes the air pollution control systems for a proposed woody biomass power plant called the Gainesville Renewable Energy Center (GREC). Recently, a number of SCR systems have been specified or actually installed on biomass boilers. The catalyst for the BFB-based GREC project will be located in the clean-side, medium temperature zone after all other air pollution control equipment and <u>before</u> the air preheaters and no reheat of exhaust gases is required.

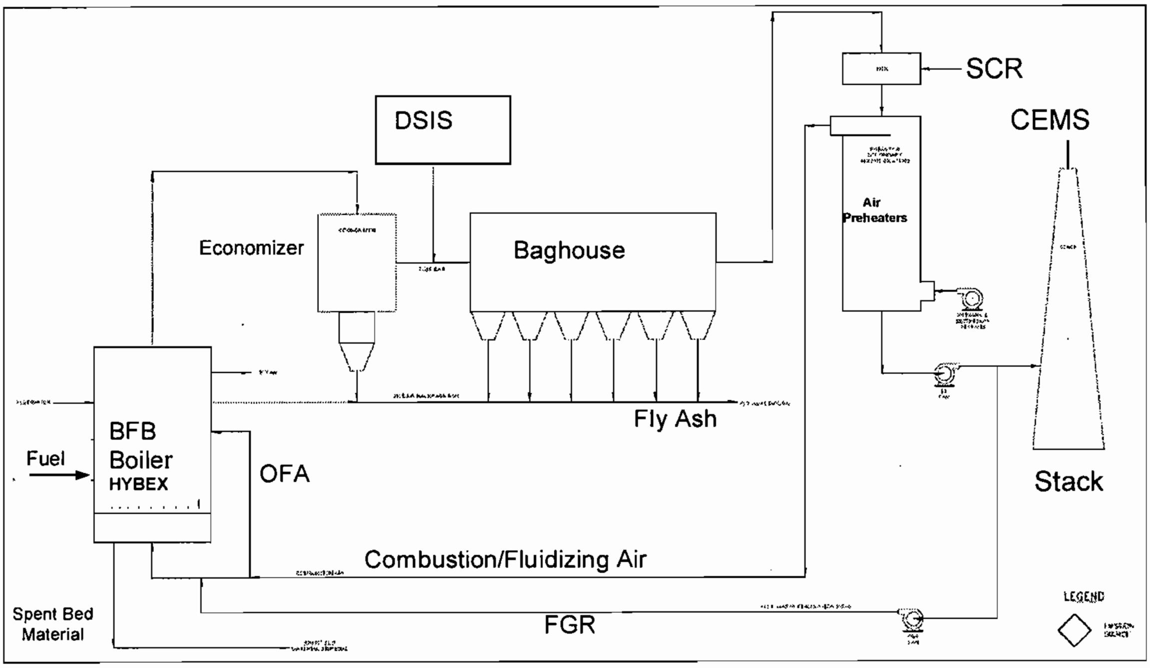


Figure 16 – Gainesville Renewable Energy Center (GREC) BFB Pollution Control Technologies

The recently permitted Florida Biomass Energy (FBE) stoker project is premised on a clean-side SCR arrangement similar to GREC (after control equipment and no reheat). FBE will also have an ESP instead of a baghouse and oxidation catalyst (ox-cat) for VOC, CO and organic HAP control. The air pollution control system will be provided by PPC; the vendor that provided the SRF project guarantees for the ESP and DSIS. The same arrangement as planned by FBE is already under construction at Aspen Power in Lufkin, Texas for a stoker boiler woody biomass project.[9]

For conventional or historical installations with the particulate control equipment located in a relatively low temperature regime <u>after</u> the air preheater, exhaust gas reheat may or may not be necessary in order to incorporate SCR on the clean side. In the example shown in Figure 17, reheat is incorporated into the clean-side SCR system at an existing 36 MW poultry litter and feathers-to-energy facility in Moerdijk, Holland.

A variation of clean-side SCR called regenerative SCR (RSCR) was developed by Babcock Power, Inc. (BPI) for the purpose of optimizing the efficiency and reducing the cost of such reheat. Ox-cat is usually part of the RSCR package. Refer to Figure 18.[10]

Basically a relatively cool exhaust stream is heated by passing through preheated thermal media (Cycle 1) called a heat recovery bed before passing through the SCR catalyst at a moderate temperature. The exhaust gas is then slightly heated by a gas-fueled duct burner. The higher heat of the exhaust gas is then imparted to a second thermal media bed. Eventually the second bed reaches a greater temperature than the first and the flow through the RSCR unit is reversed as shown in Cycle 2.

[9] Telecom. Linero, A., Florida DEP and Liebman, Neil, CEO, Aspen Power. Status of Construction at Lufkin Generating Plant. July 26, 2010.

[10] Presentation to FDEP. RSCR NO_X/CO Control Technology. Babcock Power, Inc. June 2009.

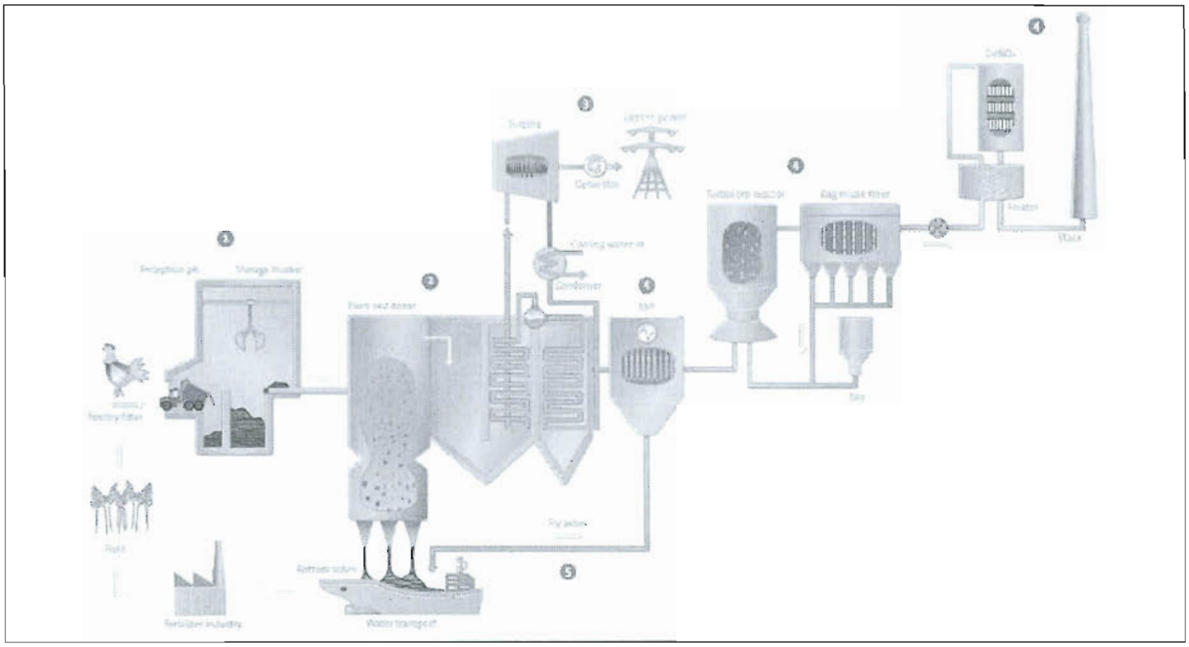


Figure 17 – Basic Process and Air Pollution Control Equipment Diagram for Moerdijk BFB Boiler

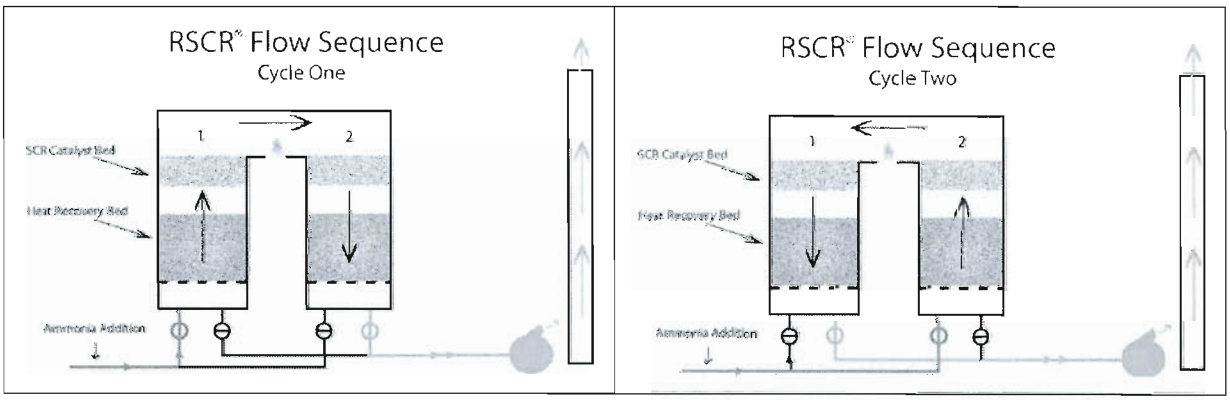


Figure 18. Principle of RSCR incorporating Duct Burner and Thermal Media (Ox-cat not shown).

Basically, the RSCR unit is a heat engine that operates at a moderate temperature while using and expelling low temperature exhaust gas. Thermodynamic losses to the environment are minimized by their arrangement. According to BPI, the RSCR system results in a net increase (system inlet to system outlet) of only 7 °F compared with 50 to 75 °F for more typical heat exchanger arrangements.

One practical benefit of a cool SCR arrangement such as RSCR is that the air preheater shown in Figure 16 can be located right after the economizer. This reduces the actual temperature and volumetric flow rate of gas through the control equipment. RSCR systems have been retrofitted downstream of PM control devices at four existing biomass power plants in Maine (Boralax Stratton and Boralex Fort Fairfield) and New Hampshire (Whitefield Power and Bridgewater Power).[11]

[11] Paper. Donovan and Holtzman. Biomass Power Plant Permitting Trends in the Northeast – Lessons Learned. Paper # 271, Air & Waste Management Association 101st Annual Conference & Exhibition, June 2008.

RSCR was also installed at a facility in Vermont (McNeil Burlington).[12] In addition to retrofits, RSCR has been specified for several proposed biomass and WTE projects including the small (38 MW) Palmer Energy biomass project in Massachusetts and the larger Fairfield WTE facility in Maryland.[13, 14] RSCR is often the benchmark against which costs and controls for new projects are weighed.

Despite perceptions to the contrary, application of SCR downstream of a low temperature PM control device do not necessarily require reheating of the exhaust gases prior to the SCR unit. CRI Catalyst (Shell Group) has for years provided low temperature SCR catalyst for use in combustion sources at chemical and refining plants as well as gas turbines and WTE plants.[15] In addition to CRI, Haldor Topsoe (HT) supplies low temperature SCR catalyst without requirement for exhaust gas reheating.[16]

CRI claims the SCR catalyst as an effective system to reduce dioxin and furan (D/F).[17] This benefit is corroborated in the literature as well as destruction of VOC.[18, 19] SCR was installed at the Algonquin Power WTE in Ontario for the dual purpose of NO_X and D/F reduction. A paper prepared by the government and the operator states:[20]

"In evaluating the technology options, it was suggested that the operating costs for SNCR would be lower than for SCR. However, the SCR system had the potential advantage of dioxin and furan destruction. Thermal oxidation of PCDD/F in the presence of a catalyst produces water, carbon dioxide (CO_2) and HCl. Therefore, SCR was the chosen technology after the evaluation of pollution control options was complete".

According to a report prepared for the Canadian Council of Ministers of the Environment (CCME), *"during commissioning testing (of the SCR system) in November 2001 the facility recorded three D/F emission concentration values well below the Environment Canada Level of Quantification (LOQ) of 32 picograms toxic equivalent (TEQ) per normal cubic meter at 11% oxygen (pg TEQ/Nm^3) @11% O_2".*[21] This equates to 0.045 nanograms (ng) TEQ/Nm^3 @7% O_2. For reference, subsequent installation of activated carbon further reduced D/F at Algonquin by at least another order of magnitude.

The possibility of low temperature SCR without reheat has been confirmed by the Department's inquiries regarding the operation of at least two of the RSCR installations in New England. According to discussions with the operator at Whitefield Power, NH, the duct burners are not actually used although the NO_X limit is continuously achieved.[22] Operators at the Bridgewater Power, NH facility has made the same determination and this finding has been documented in a permit modification that provides for a lower minimum operating temperature for the RSCR system. The rationale is as follows:

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12 Press Announcement. www.babcockpower.com/?p=465 . Babcock Power RSCR® Reduces Vermont Air Emissions. April 21, 2009.

13 Public Notice. www.mass.gov/dep/public/hearings/predcahn_cn.htm . Massachusetts Department of Environmental Protection. November 2009.

14 Fact Sheet. www.mde.state.md.us/assets/document/Air/MDE_OC_EA_facility_factsheet.pdf . Energy Answers, International WTE project. Published by the Maryland Department of the Environment. July 2010.

15 CRI Web Link. www.cricatalyst.com/products/environmental/noxreduction.aspx .

16 Baviro Roosendaal Web Link. www.baviro.nl/SCR_nl.html .

17 Paper. Tang, H.S. The Shell Dioxin Destruction System. Solid & Hazardous Waste Management Conference, Singapore, February 2003. www.cricatalyst.com/products/pdfs/sporeconference.pdf

18 E.g. Tzimas, E., and Peteves, S.D. NO_X and Dioxin Emissions from Waste Incineration Plants. Joint Research Center, European Commission. Circa 2001.

19 E.g. Leibacher, U., Bellin, C., and Linero, A. High Dust SCR Solutions. International Cement Review. December 2006. www.cementeriadimonselice.it/pdf/HD_SCR_solutions.pdf

20 Paper. A Case Study of the SCR System at the Algonquin Power WTE Facility. Annual NA WTE Conference. NAWTEC 16-1903. 2008. www.seas.columbia.edu/earth/wtert/sofos/nawtec/nawtec16/nawtec16-1903.pdf

21 Report. Review of Dioxins and Furans from Incineration in Support of a Canada-wide Standard Review. CCME Project #390-2007. December 15, 2006. www.ccme.ca/assets/pdf/1395_d_f_review_chandler_e.pdf

22 Telecom. Heron, T., Florida DEP and York, D., Whitefield Power. August 2, 2010.

"Since permit issuance, Bridgewater has found that at times of optimal boiler efficiency, the inlet temperature to the RSCR can be as low as 315 degrees F. This results in a corresponding bed temperature of the same value. At 315 degrees F, the outlet NO_X emission rate from the RSCR remains below the desired 0.075 lb/mmBtu and all other criteria pollutants remain below permit limits. In addition, no new pollutants are emitted from the Boiler. As a result of this, Bridgewater has requested that the temperature range be changed from 350 to 650 degrees F to 315 to 650 degrees F." [23]

The manufacturer of the NO_X catalyst used at the mentioned RSCR facilities is Cormetech. Note that the ox-cat is also effective at lower temperatures than previously believed by some operators and agencies.

Applicant's Proposal for NO_X. Refer to Table 6. The applicant's original BACT proposal was 0.14 lb/mmBtu (stoker) and 0.10 lb/mmBtu (BFB) on a 30-day rolling basis based on SNCR. These values have since been revised to 0.10 lb/mmBtu for either option by SNCR, SCR or a combination of the two technologies.

The applicant conducted a top/down BACT analysis for NO_X from the biomass boiler based information in the RACT/BACT/LAER Clearinghouse (RBLC) as well as cost-effectiveness calculations based on vendor quotes.

SRF determined that SNCR is technically feasible and calculated a capital cost of approximately $1,768,222 and an average cost-effectiveness of $1,393/ton NO_X removed for the stoker option. The Department accepts the estimate by SRF and notes that a guarantee was provided from FuelTech who provided an SNCR system for the larger USS Boiler No. 8 installation. SRF determined that SCR is technically feasible, but rejected SCR as BACT on the basis of cost-effectiveness for both the stoker and BFB boiler options. In their most recent submittal, SRF reiterated that SCR is not cost-effective but, nevertheless, proposed SNCR, SCR or a combination of the two technologies to meet their latest proposal.

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Evaluation of Applicant's NO_X Proposal. The Department notes that SNCR typically requires more injection of reagent per unit of NO_X in the gas stream and per unit of NO_X removed compared with SCR. This is caused by the tendency to form some additional NO_X through the combustion of NH_3 or urea in the furnace requiring even more NH_3 or urea to abate the additional NO_X. The excess reagent requirements are characterized as NH_3 slip which can contribute to fine particulate ($PM_{2.5}$) formation and plume opacity as condensed ammoniated sulfates, chlorides and nitrates.

SRF determined that SCR before the PM control device (which they call "conventional SCR") is not feasible for the stoker option for following reason:

"Catalyst poisoning due to wood/bagasse combustion would occur because of the alkali content of the ash. Given the high PM loading in the flue gas prior to the ESP, premature catalyst deactivation would occur due to the chemical poisoning of the catalyst. Based on an analysis of bagasse at SRF, which contains approximately 5 to 6% ash, the ash has an average of 0.5 % sodium (Na), 12% potassium (K), 5% phosphorus (P), 1.5% sulfur (S), and over 4 % chlorides (Cl) (all on a wet 50-percent moisture basis). Based on an analysis of wood ash from a facility similar to SRF, wood is approximately 9 to 10% ash, and an average of 1.7% Na, 4.0% K, 1.5% P, 2.0% S, and over 1.3% Cl. Based on these analysis,

[23] Permit Amendment. Bridgewater Power Company. Temporary Permit TP-B-0533. Issued September 12, 2007. www2.des.state.nh.us/OneStopPub/Air/3300900021FY08-0501TypeSummary.pdf

Table 6 - Emissions in lb/mmBtu – Boilers with Uses or Capacities Similar to Proposed Project

Project Location	CO	VOC	NO_X	PM/PM_{10} [b]	SO_2
SRF, Hendry County Ethanol and Power Sorghum bagasse, wood, biogas, VLSD fuel oil, propane, yard waste < 30%. 488 mmBtu/hr (average)	**0.10** 30-day GCP	**0.010** stack test GCP	**0.10** 30-day SNCR/SCR	**0.015 (f)** stack test ESP	**0.11/0.088** [c] 24-hour/30-day sorbent in ducts
HEF Ethanol, Highlands County, FL BFB - stillage, wood, gas, ULSD FO ~198 mmBtu each (2010)	0.10 30-day GCP	0.005 stack test GCP	0.075 30-day SNCR	0.01 (f) Stack test fabric filter	0.06 30-day BFB limestone
Palmer Renewable, MA grate stoker boiler – woody biomass 509 mmBtu/hr (draft 2009)	0.070 4-hour Ox-cat	0.010 stack test Ox-cat	0.060 1-hour RSCR	0.012, 0.02 (f, f+c) stack test fabric filter	0.02 1-hour dry scrubber
Aspen, Lufkin, Angelina Co., TX grate boiler – woody biomass ~692 mmBtu/hr (2009)	0.075 30-day Ox-Cat	0.010 stack test Ox-Cat	0.075 30-day SCR	0.012 (f) stack test ESP	0.025 stack test sorbent in ducts
Lindale, Smith Co., TX grate stoker boiler – woody biomass ~684 mmBtu/hr (2009)	0.31 30-day GCP	0.017 stack test GCP	0.15 30-day SNCR	0.02, 0.026 (f, f+c) stack test fabric filter	0.025 30-day low sulfur fuel
FBE, Manatee County, FL grate stoker boiler – woody biomass ~757 mmBtu/hr (2010)	~0.0295 (eq) [a] 12-month Ox-cat	~0.003 (eq) stack test Ox-cat	~0.020 (eq) 12-month SCR	0.01 (f) stack test ESP	~0.016 12-month sorbent in ducts
ADAGE, Hamilton County, FL BFB – woody biomass ~758 mmBtu/hr (2010)	~0.074 (eq) 12-month GCP	~0.017 (eq) stack test GCP	~0.070 (eq) 12-month SCR	0.029 (f+c) stack test fabric filter	~0.045 (eq) 12-month sorbent in ducts
GREC, Alachua County, FL BFB – woody biomass 1,358 mmBtu/hr	0.12/0.08 [c] 30-day GCP	~0.010/0.009 [c] stack test GCP	0.070 24-hour SCR	0.015, 0.042 (f, f+c) stack test fabric filter	~0.029 24-hour sorbent in ducts
Yellow Pine, Ft. Gaines, GA BFB - woody biomass, tires 1529 mmBtu/hr (2010)	0.15 30-day GCP	0.02 stack test GCP	0.10 30-day SNCR	0.018 (f+c) stack test fabric filter	0.14 30-day dry scrubber
U.S. Sugar (USS) Clewiston, FL grate stoker boiler - bagasse ~1,000 mmBtu/hr (2003)	0.38 12-month GCP	0.05 Stack test GCP	0.14 30-day SNCR	0.026 (f) stack test fabric filter	0.06 30-day no control
Okeelanta CoGen, South Bay, FL 3 grate stoker boilers – bagasse 715 mmBtu/hr each (1993)	0.35 8-hour GCP	0.06 stack test GCP	0.15 30-day SNCR	0.03 (f) stack test ESP	0.02 30-day low sulfur fuel
Wheelabrator, Auburndale, FL grate stoker boiler – wood and tires ~630 mmBtu/hr (1992/1995)	0.32 30-day GCP	0.035 stack test GCP	0.14 30-day SNCR	0.02 (f) stack test fabric filter	0.10 30-day lime spray
NSPS Subpart Db Propane, wood, ULSD fuel oil ≤250 mmBtu/hr	No standard	No standard	~0.020	0.030 (f) or 20% opacity [d]	~0.020
Draft 40 CFR 63, Subpart DDDDD	~0.031/0.44 [e]	No standard	No standard	0.008 (f)	No standard

a. In certain cases, the enforceable limits are in terms of lb/hr or TPY and the lb/mmBtu denoted by "eq" are for comparison purposes only.

b. "f" denotes filterable fraction and "c" denotes condensable fraction.

c. The values indicated include the contribution from biogas. Excluding the biogas, the values are 0.05/0.025 lb/mmBtu on 30-day/24-hr bases.

d. 20% opacity except for one 6 minute period per hour of 27% opacity.

e. Major HAP source BFB/Stoker options. Converted from parts per million at 3 percent oxygen (ppm @ 3% O_2); 40 ppm for BFB boiler and 560 ppm for stoker boiler.

the potential for chemical poisoning and premature deactivation of the catalyst is very high and makes conventional SCR an inappropriate choice for NO_X control of the cogeneration boiler."

While the Department does not necessarily agree with this conclusion (in the face of numerous successful installations of "dirty-side SCR" at coal-fueled power plants), the Department agrees with the logical implication that the possibility of catalyst deactivation will be lessened by placement of the SCR unit after the control equipment. The Department also notes the concern by SRF regarding the presence of Cl given the potential for HCl emissions.

SRF initially provided a capital cost estimate of $14,552,100 and an average cost-effectiveness of $5,380/ton NO_X removed on the basis of an RSCR system to reduce emissions from 0.35 to 0.075 lb NO_X/mmBtu. Under this scenario, no credit is given for the simultaneous reduction of CO. According to the original submittal by SRF, the cost-effectiveness of simultaneous NO_X/CO removal is $2,830/ton CO/$NO_X$ removed. SRF provided a marginal cost-effectiveness of $17,505/ton NO_X removed to obtain the further reduction by SCR compared to SNCR from 0.14 to 0.075 lb/mmBtu.

The Department advised SRF to obtain an actual project specific quotation which resulted in a bid of $7,000,000 including erection and installation. After adjustments for certain excluded items at over $1,000,000 and over $3,000,000 in indirect capital costs, the final capital cost estimate calculated by SRF is $11,109,000.

Despite the lower capital cost, SRF recalculated the average cost-effectiveness of SCR at $5,846/ton NO_X removed - even greater than the previous estimate. SRF recalculated the marginal cost-effectiveness compared with SNCR at $24,417/marginal ton of NO_X removed. SRF rejected RSCR on the basis of the cost effectiveness. BPI estimates the cost-effectiveness of its RSCR product at $3,603/ton NO_X removed.[24]

The Department adjusted the SRF RSCR estimates for the following reasons:

- The NH_3 cost at a molar ratio (NH_3 in/NO_X in) of 1.0 will only be $280,000 rather than $638,400 given in the SRF cost-effectiveness analysis;[25]
- The annual supplementary propane expense of $478,800 will not be needed based on the experience of other RSCR installations; and
- The technology is capable of achieving 90% reduction to 71 TPY of NO_X and 0.035 lb/mmBtu (30-day basis).

These adjustments are sufficient by themselves to reduce the average cost-effectiveness of SCR to $3,814 without considering deductions of the annualized costs for the thermal media, duct burners and the associated erection, installation and proportioned annual costs.

PPC, who earlier provided the ESP/DSIS quote used in the application, was invited by SRF to quote the pollution control system to add SCR and ox-cat units to their original submittal. According to SRF, the bid by PPC indicated additional capital costs of approximately $1,500,000. SRF disqualified PPC's bid because according to SRF: the SCR cost leaves out several necessary items; the cost quote is too low to be realistic; the guaranteed catalyst life is 8,400 hours; and the vendor has no operating experience utilizing SCR on a biomass boiler.[26]

The disqualification is curious because PPC is actually supplying SCR and ox-cat (as well as the ESP/DSIS) for the Lufkin project, which is actually under physical construction and they will provide the SCR and ox-cat for the Florida Biomass Energy (FBE) project recently permitted by the Department. The

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24 Presentation to FDEP. RSCR NO_X/CO Control Technology. Babcock Power, Inc. June 2009.

25 Electronic Mail. Linero, A., FDEP to Buff, D., Golder. Southeast Renewable Fuels - SNCR/SCR Costs. July 21, 2010.

26 Letter. SRF to FDEP. Southeast Renewable Fuels, LLC, Response to FDEP Letter dated August 6, 2010.

Department advised SRF that "it may be prudent to further discuss their attractive estimate rather than disqualifying them especially given the 90% NO_X reduction guarantee to 0.04 lb/mmBtu".[27]

The Department believes the true costs for the SCR and ox-cat systems for an integrated design will lie between the $5,600,000 equipment costs estimated by BPI that included thermal media, and duct burners and the $1,500,000 system quoted by PPC. Taking the average for a low temperature system without reheat yields $3,550,000. Allowing a doubling for the additional components and installation yields $7,100,000. Using the lower capital cost recovery factor than estimated for the RSCR technology yields an average cost-effectiveness less than $3,000/ton NO_X removed. This includes no consideration for the value of CO, VOC, organic HAP, NH_3, $PM_{2.5}$ and D/F reduction benefits of SCR/ox-cat or the RSCR.

For reference, in the updated information submitted on October 12, 2010 the applicant showed a basic estimate by PPC of $5,500,000 for a DSIS/ESP installation and a separate estimate of $12,500,000 including a DSIS/ESP/SCR/ox-cat installation. This difference is the cost of the SCR/ox-cat systems and is in line with the Department's estimate in the preceding paragraph. It is noted that the updated cost from PPC is likely from the Lufkin project where the project was stopped while under construction and expensive redesign and relocation of certain equipment was required. A bid prior to the start of construction of SRF would be less than estimated for the Lufkin project.

After corrections to the bids obtained by SRF, the SCR/ox-cat system will cost approximately $1.77 million per year compared with $1.0 million for an SNCR system, for a difference of $770,000/yr. Assuming the plant will make 22,110,000 gallons of ethanol per year and 210,000 MWH (at 25 MW and 8,400 hr/yr) the impacts of SCR over SNCR on the cost of the products (by equal allocation to ethanol and power sales) are $0.017 per gallon of ethanol (< 2 ¢/gallon) and $0.0019/kWH (less than 0.2 ¢/kWH).

For reference Progress Energy signed a Power Purchase Agreement (PPA) with FBE for renewable energy at an initial price of 7.1 ¢/kWH with a negotiated escalator of 1.5% per annum. Presumably, SRF can do as well. Also the present cellulosic ethanol tax credit for which SRF might eventually qualify (due to the use of the field residue and bagasse as fuel) is $1.01/gallon.

Department's Review. According to its definition, BACT is based on the technology the "Department determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques)".

The use of a BFB boiler versus stoker boiler involves just variations within the same production process which in the present case is combustion of biomass in a furnace to produce steam and electric power. The Department would be well within the scope of BACT to specify a BFB boiler versus a stoker. BACT includes treatment and such treatment can improve the emission profile of a stoker to a level where is equals that of a BFB boiler. Therefore, it is not necessary, though allowable, to specify a BFB boiler over a stoker boiler.

Notably, the NO_X limits specified in Table 6 for FBE, Aspen (Lufkin) and Palmer Renewable as a group (stoker boilers) are competitive with the limits for GREC, ADAGE and Highlands Ethanol (BFB boilers).

The Department has determined that BACT for this project is 0.10 and 0.08 lb NO_X/mmBtu (30-day average) for stoker and BFB boilers, respectively on the basis of incorporating GCP and SCR or SNCR (or a combination of the two).

The Department has determined lower BACT values for certain other projects in Florida. However the applicant's latest proposal for the present project is adequate for a state PSD BACT determination given that the emissions are controlled to a level less than the federal PSD threshold of 250 TPY for this particular industry (ethanol production facilities that produce ethanol by natural fermentation).

[27] Letter. FDEP to SRF. Southeast Renewable Fuels, LLC, Status of Permit Review. August 26, 2010. www.dep.state.fl.us/Air/emission/bioenergy/southern_renewables/SERStatusIII.pdf

The 30-day averaging time and higher value (compared with the lowest woody biomass determinations) will make it easier to obtain a guarantee for an extended catalyst lifetime if they choose to install SCR catalyst.

SO_2 and SAM Emissions

Discussion. SO_2 is primarily formed from S compounds contained in biomass. SAM is formed by further oxidation of SO_2 to sulfur trioxide (SO_3) prior to exiting the process. SO_3 readily combines with water vapor (H_2O) available in flue gas to form SAM.

According to the original application, the biomass boiler is expected to emit 161 TPY of SO_2 of which 132 TPY was estimated by the combustion of biogas in the boiler. The applicant projected emissions of 7.9 TPY of SAM.

The boiler is designed to burn sorghum bagasse and harvest residue as the primary fuel. Supplemental fuels are biogas from the bioreactors, clean wood, yard trash, VLSD fuel oil and propane. Refer to Table 7.

Table 7 - Characteristics of Typical Biomass and Fossil Fuels – Heating Value, Ash and S

Fuel Class	Fuel	Gross Heating Value Btu/lb	Ash (%)	S (%)
Bioenergy Feedstocks	SRF bulk sorghum	6,570	5.5	0.15
	SRF sorghum bagasse	3,800 (wet)	5.8	0.09
	HEF stillage	4,200 (wet)	7	0.08
	sugarcane bagasse (generally)	7,720	3.2-5.5	0.10-0.15
	USS bagasse	3,600 (wet)	2.6-5.3	0.03-0.07
	SRF wood estimate	4,250 (wet)	9.0	0.07
	hardwood	8,745	0.45	0.009
	softwood	8,360	0.3	0.01
	hybrid poplar	8,105	0.5-1.5	0.03
	bamboo	8,085	0.8-2.5	0.03-0.05
	switchgrass	7,810	4.5-5.8	0.12
	miscanthus	7,785	1.5-4.5	0.1
	arundo donax	7,295	5-6	0.07
Liquid Biofuels	bioethanol	11,940	~0	<0.01
	biodiesel	17,050	<0.02	<0.05
Gas Biofuels	Biogas	10,083		2.0 H_2S
Fossil Fuels	Coal (low rank)	6,400-8,100	5-20	1.0-3.0
	Coal (high rank)	11,500-12,800	1-10	0.5-1.5
	ULSD	18,150	negligible	<0.0015
	NG	1,030 Btu/cubic foot	negligible	< 0.002

Biomass entering the ethanol process (e.g. sorghum) at SRF will be typically low in S content. A figure of 0.09% S (wet basis) was provided in the application. This value is included in Table 7 along with heating value, ash and sulfur content of various types of biomass and fossil fuels. The values are on a dry basis except as otherwise noted. The biogas is high in S as H_2S due to anaerobic digestion of sulfur added within the ethanol process as sulfuric acid.

Applicant's Proposal for SO_2 and SAM; The applicant's BACT proposal applicable to all fuels except the biogas is 0.025 lb SO_2/mmBtu on a 30-day basis. Considering the contribution of the biogas, the actual proposal is equal to 0.11 lb SO_2/mmBtu on a 24-hour basis and 0.088 lb SO_2/mmBtu on a 30-day. The applicant proposed a SAM limit of 0.0037 lb/mmBtu (3-hour test) on the basis of 4.9% conversion of SO_2 to SO_3.

The proposed control technology for the BFB boiler option is limestone injection into the bed and a DSIS utilizing hydrated lime [Ca $(OH)_2$] or trona or other proprietary chemical. The proposed control technology for the stoker option is a DSIS utilizing $Ca(OH)_2$ or trona or other proprietary chemical. In both cases, inherently low sulfur fuels will be used with the exception of the biogas.

The DSIS will augment the removal of SO_2 and SO_3 by the alkaline fly ash. Both species are then removed as PM in the ESP. Additional control of SAM can be effected by controlling the excess air available in the furnace (to the extent allowed considering the NO_X and CO strategies).

Department's Review. The proposed values of 0.11 and 0.088 lb/mmBtu on 24-hour and 30-day bases, respectively are high compared with all of the other projects listed in Table 6. The primary cause is the combustion of biogas in the boiler containing 2% H_2S or 4.58 lb SO_2/mmBtu (uncontrolled). Because of occasional flaring of the biogas, there would be a modeled violation of the new 1-hour national ambient air quality standard (NAAQS) when the flare is employed. Consequently SRF proposed a small wet scrubber to remove H_2S from the biogas, thus controlling SO_2 from the flare by 98% to 0.092 lb/mmBtu.

Department's BACT Determination for SO_2. In addition to treating the biogas when flaring, continuous use of the H_2S scrubber is possible to also pretreat the biogas prior to combustion in the boiler. The DSIS will further control the biogas combustion product from 0.092 to 0.023 lb SO_2/mmBtu. The resultant value is approximately equal to the controlled SO_2 emissions rate of 0.025 lb/mmBtu from biomass combusted in the boiler.

The Department will set the BACT limit at 0.025 lb SO_2/mmBtu on a 30-day basis. The control technology (low sulfur biomass, limestone as applicable and DSIS and H_2S scrubber to the extent required to meet the limit) proposed by SRF is acceptable. The value is in the range of recent determinations compared with most of the examples in Table 6.

The Department will specify use of ULSD fuel oil rather than VLSD fuel. The applicant had proposed VLSD but alternatively gave sulfur specifications indicative of ULSD and VLSD fuel throughout the application documents.

In general, it is cost effective to treat high concentration/low volume streams such as the biogas before combustion and control of SO_2 provides control of a $PM_{2.5}$ precursor and condensable PM and PM_{10}. Also, minimizing SO_2 will help improve low temperature catalyst performance and lifetime. The source is close to the fenceline and SO_2 control will provide greater assurance of compliance with the recently promulgated 1-hour SO_2 NAAQS. Compliance shall be demonstrated by a SO_2-CEMS.

Department's non-BACT determination for SAM.

The scrubbing of the biogas and the DSIS will also reduce SAM to the point where PSD is not triggered. The Department will set a value equivalent to 0.003 lb SAM/mmBtu (equal to 6.14 TPY) to insure PSD is not triggered. The strict SO_2 BACT limit and the SO_2-CEMS together with initial and annual SAM tests will provide reasonable assurance of continuous compliance.

CO and VOC Emissions

Discussion. Refer to the previous descriptions of the BFB boiler and stoker boiler operation. CO and VOC (including organic HAP) are products of incomplete combustion. Combustion in the BFB boiler bed and lower furnace occurs in substoichiometric conditions. As a result, a great deal of CO is evolved as well as VOC (including hydrocarbon radicals and other species). The CO, hydrocarbon radicals and reduced nitrogen compounds (as previously mentioned) participate in reactions that assist in primary NO_X control. Analogous mechanisms occur in the stoker boiler.

Sufficient OFA, temperature and turbulence is necessary to complete the burnout of CO, fine char and VOC. Clearly throttling NO_X formation by staging combustion using the OFA ports affects CO and VOC formation in the furnace. Basically, the manner by which the boiler is operated (e.g. favoring NO_X over CO/VOC control) is part of an overall source emission strategy that considers the emissions limits and costs of add-on controls.

This fact can be appreciated in Figure 19 from a B&W publication that demonstrates the modeled relative effects upon CO when switching to a low NO_X control strategy. Under the low NO_X strategy (newly designed air system including higher OFA ports) moderate levels of CO (and presumably VOC) persist at greater heights within the furnace compared with the previous combustion strategy.

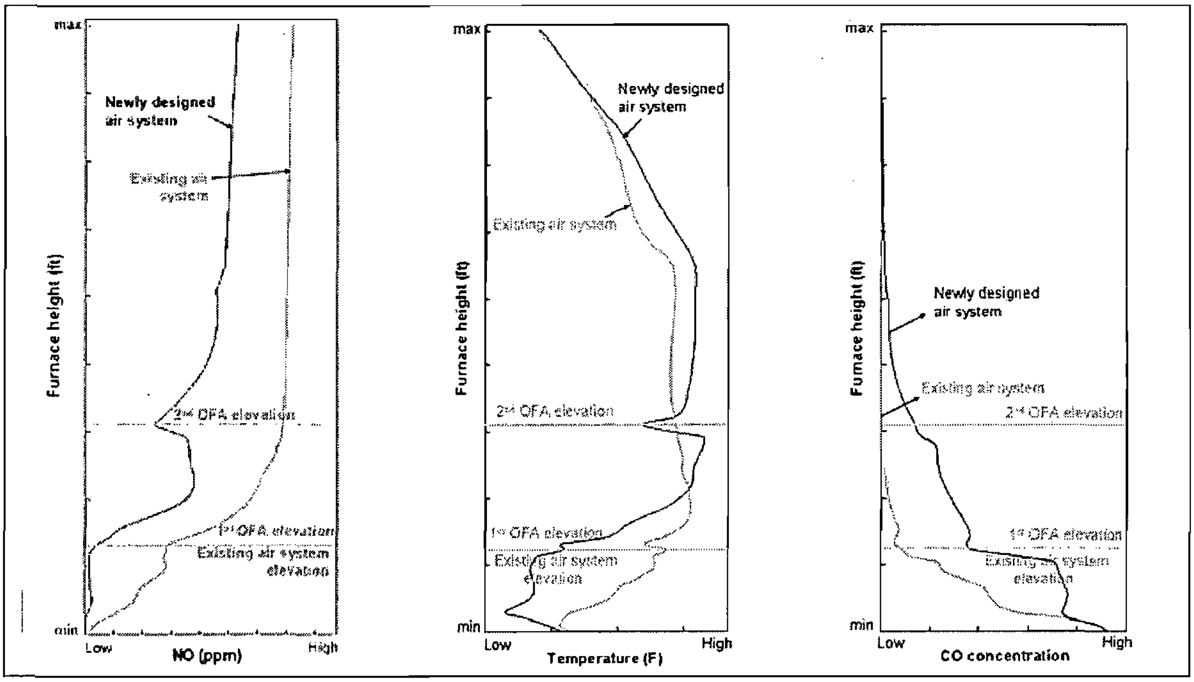


Figure 19. Modeled NO_X, Temperature and CO a BFB Boiler after Switching to Low NO_X strategy.

According to the article, *"in favor of achieving low NO_X emissions, higher CO values were accepted in the Precision Jet air system. However, these CO emissions were well within the acceptable range to meet state and federal requirements".* [28]

The GCP incorporated within the boiler design consists of: intimate contact between the bed material (BFB boiler) and the fuel and sufficient turbulence, temperature and residence time above the OFA ports (both boiler designs) to the extent allowed by a low NO_X strategy.

If GCP are not sufficient to achieve low CO and VOC emissions, an oxidation catalyst (ox-cat) is an option. As in the case of SCR catalyst, the preferred location of an ox-cat system is after the PM control device (i.e. the ESP proposed by SRF).

<u>Applicant's Proposal for CO and VOC.</u>

The applicant's original BACT proposal was 0.17 lb CO/mmBtu (30-day) and 0.025 lb VOC/mmBtu for the BFB boiler option. The applicant originally proposed BACT emission limits of 0.33 lb CO/mmBtu (30-day) and 0.05 lb VOC/mmBtu for the stoker option.

[28] Dessam et al, B&W. Use of Numerical Modeling for Designing a Biomass-fired BFB Boiler Air System for Low NO_X Emissions. 2009 Power-Gen International Conference. Las Vegas December 2009.

These values have since been revised to 0.10 lb CO/mmBtu (30-day) and 0.010 lb VOC/mmBtu for either boiler option by GCP with or without ox-cat.

The applicant proposes an advance OFA combustion design and controls for boiler CO controls. The applicant evaluated enhanced OFA systems for economic impacts and concluded that *"although potentially capable lowering CO up to 25%, is also costly and unproven on a bagasse -fired boiler"*.

An enhanced OFA system was present in Table 5-13 of the application. The applicant calculated the capital costs at approximately $3,084,415 and the annualized costs at more than $478,794 per year. The calculated cost effectiveness is $2,900/ ton of CO removed ($/ton).

According to the applicant, *"CO oxidation with RSCR is the most effective method for controlling CO emissions and will achieve the maximum degree of CO emissions reduction. RSCR has an estimated CO removal of 80%, based on a quote for RSCR provided by Babcock Power"*.

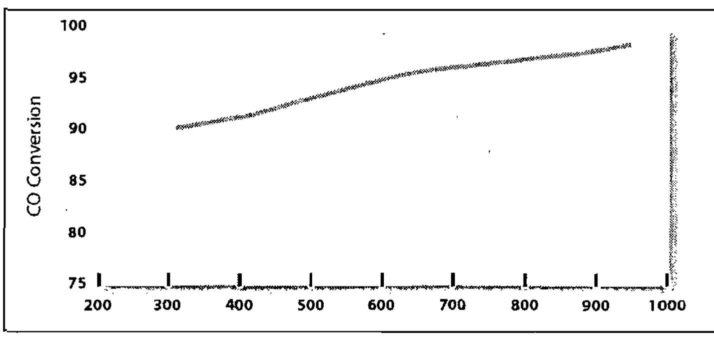
The project-specific RSCR bid and adjustments by SRF (and the Department) are discussed in Section 4.2 above. According to the applicant, the cost of RSCR is extremely high for CO reduction only, and only achieves a small incremental reduction in NO_X emissions.

Department's Review. A comparison of the proposed CO and VOC values for the SRF project with other biomass projects is given in Table 6 above. With an SCR system (versus SNCR), it is possible to make adjustments in the furnace low NO_X strategy (while compensating with the add-on SCR) so that CO and VOC emissions can be significantly reduced. Without SCR, it certain that ox-cat would be cost-effective to reduce CO and VOC emissions. As discussed in Section 3.5 above on HAP, further reasonable assurance is required to insure that the facility is not a major source of HAP. Installation of ox-cat would provide that assurance and provide BACT level CO and VOC emission limits.

Ox-cat, like SCR, can also function in a low temperature environment as discussed in NO_X emissions section above. Again, the stoker biomass boiler facilities in New Hampshire are able to meet their emission limits without use of the reheat equipment provided in their RSCR systems.

In its application, SRF states, *"CO emissions can be reduced by passing the flue gas over an oxidation catalyst at suitable temperature (900 to 1,000 °F)"* and *"the temperature profile of the flue gas does not match the temperature requirements of typical catalysts"*.

Refer to Figure 20. The information in the curves suggests that ox-cat is effective for CO removal at temperatures as low as 300 °F.[29] Clearly this allows installation downstream of the PM device and obviates the claimed necessity of reheat. The exit stack temperature from the SRF boiler is estimated at 361 °F. Moreover, ox-cat is even more effective in destroying formaldehyde (CH_2O - the HAP emitted in the greatest amount from the SRF boiler) than its effectiveness in destroying CO. Additionally both PPC and BPI provided proposals including ox-cat operating at temperatures much less than 900 to 1000 °F.



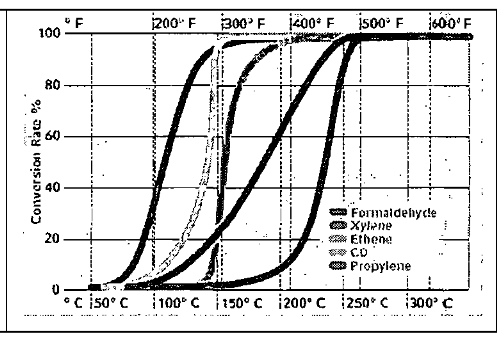


Figure 20. Ox-cat Performance vs. Temperature (°F) **Ox-cat Performance vs. Temperature (°C)**

[29] Brochures. Sud-Chemie and Johnson-Matthey.

As a final note, not all ox-cat manufacturers make products for use in biomass applications. Both RSCR and the PPC installations specify a very specific class of ox-cat that is optimized for biomass combustion.

Department's BACT Determinations for CO and VOC. The Department would be acting well within the scope of BACT to specify a BFB boiler versus a stoker to control CO, VOC and organic HAP. Treatment by installation of ox-cat can improve the emission profile of a stoker to a level that is equal or (as shown for FBE) superior to a BFB boiler without ox-cat. Therefore, it is not necessary, though allowable, to specify a BFB boiler over a stoker boiler even though the applicant has stated emissions from the stoker technology are inherently greater than the BFB technology.

Notably, the CO and VOC limits specified in Table 6 for FBE, Aspen (Lufkin) and Palmer Renewable as a group (stoker boilers) are competitive with the limits for GREC, ADAGE and Highlands Ethanol (BFB boilers).

The Department has determined that BACT for this project is 0.10 lb CO/mmBtu (30-day average) and 0.010 lb VOC/mmBtu. Although several projects listed in Table 6 have lower CO and VOC limits, the applicant's updated proposal is adequate for a state PSD BACT determination given that the emissions are controlled to a level less than the federal PSD threshold of 250 TPY for this particular industry (ethanol production facilities that produce ethanol by natural fermentation).

Ox-cat would very likely be required to achieve these limits from a stoker boiler. Ox-cat may or may not be necessary to achieve these limits if SNCR is employed for NO_X control in the case of the BFB boiler. If the applicant installs SCR for either boiler configuration, it may be possible to meet the CO and VOC limits without ox-cat by employing a higher NO_X/lower CO strategy in the furnace.

The low VOC limit (and resulting low organic HAP emissions) will (together with other measures enumerated further below) help insure the project will not be a major source of HAP. Compliance with the CO limit shall be demonstrated by a CO-CEMS. Initial and annual VOC compliance tests will be required.

PM/PM_{10}/$PM_{2.5}$ and Visible Emissions (VE)

Discussion. PM/PM_{10}/$PM_{2.5}$ are formed from ash contained in the biomass, products of incomplete combustion and from chemical reactions between products of combustion that form alkali and ammoniated chlorides, sulfates, nitrates and other such species.

The most well-known controls include cyclones, electrostatic precipitators (ESP), fabric filters and wet scrubbers. Supplementary controls include strategies such as minimization of $PM_{2.5}$ and VE precursors by limiting SO_2, NO_X, NH_3, VOC and chlorides.

The most effective types of direct PM control equipment applied to biomass boilers are fabric filters and ESP. Fabric filters, where technically feasible, are the preferred PM control device because they provide better control for fine PM.

Applicant's Proposal for PM/PM_{10}/$PM_{2.5}$ and VE Limits. The applicant's updated BACT proposal for PM/PM_{10} is 0.015 lb/mmBtu for filterable (f) PM/PM_{10} based on an ESP (following a wet sand cyclone). According to SRF, *"fabric filters are considered technically infeasible for application to the spreader stoker type boiler. There are only few known applications of a fabric filter to a spreader stoker biomass-fired boiler (see Table 5-1), and the fabric filter was used due to the use of a spray dryer for SO_2 control".*

SRF proposes an alternative monitoring procedure (AMP) for a surrogate to VE that relies on the measurement of total power input to the ESP as monitored by secondary voltage and secondary current to each field rather than on a continuous opacity monitoring system (COMS).

Department's Review. The proposed PM/PM_{10} limit is less than the NSPS,Sub part Db limit of 0.03 lb/mmBtu (f) applicable to units that (like SRF) burn less than 250 mmBtu/hr of fossil fuel. The capacity of the SRF boiler is 536 mmBtu/hr for all fuels combined. For reference, the proposed PM/PM_{10} limit is equal to the limit of 0.015 lb/mmBtu (f) applicable to boilers (those subject the NSPS, Subpart Da) burning a variety of fuels including at least 250 mmBtu/hr of fossil fuels.

EPA recently proposed NESHAP, Subpart DDDDD for new biomass BFB and stoker boilers and included a limit of 0.008 lb/mmBtu (f) for new major HAP sources and for new sources installed at existing major HAP sources.[30] Although the SRF facility will not be a major HAP source (due to Department control equipment requirements), it is still fair in a top/down determination to compare the BACT recommendation with what has been proposed for similar biomass units.

The Department reviewed the initial and annual compliance tests conducted at the USS Bagasse Boiler No. 8 (ESP installed by PPC) from 2005 to 2009 inclusive and found that the range of emissions was 0.004 to 0.015 lb PM/mmBtu with an average of 0.0089 lb/mmBtu. PPC recently provided a guarantee to FBE of 0.01 lb PM/mmBtu. Although the applicant recently proposed a limit of 0.015 lb PM/mmBtu for the stoker option (to match their original proposal for the BFB option), it should be possible for PPC to provide equipment to comply with the 0.01 lb PM/mmBtu value.

In the case of the Aspen Power (Lufkin, TX) biomass grate stoker power project listed in Table 6, the State of Texas Council of Environmental Quality (TCEQ) initially issued a permit with a PM limit of 0.025 lb/mmBtu. The permit was appealed while the project was already under construction. After an ensuing settlement and remand to TCEQ, the permit was reissued with a limit 0.012 lb PM/mmBtu (f).[31] PPC was contracted by the operator to modify its ESP design to meet the revised limits (and to add SCR and ox-cat).[32] As a result of the same case, NO_X and CO emissions were reduced by 50 and 75%, respectively.

The Department reviewed the request for an AMP in lieu of a VE limit. According to the definition given above, BACT is *"an emission limitation, including a **visible emissions** standard."* (emphasis added). It is practicable to set a VE limit and to install a COMS to measure opacity. Although EPA Region 4 allowed, by letter, the use of the AMP in the case of USS Bagasse Boiler No. 8, the action was limited to compliance with the relevant NSPS 20% VE standard and would not provide reasonable assurance of continuous compliance with the lower BACT 10% VE limit for the present project.[33]

In determining the feasibility of a VE limit and COMS, the Department reviewed compliance tests conducted at USS Bagasse Boiler No. 8 following construction and information from the SRF application and found the following:

- USS Bagasse Boiler No. 8 includes a wet sand cyclone in front of the ESP;
- The stack temperature at USS Boiler No. 8 is in the range of 300-325 °F suggesting that no water vapor should form in the stack;[34]
- The moisture content of the exhaust gas at the stack is in the range of 25-30%;
- The projected stack temperature at the SRF stack is 361 °F at 20% moisture;

[30] Proposed Rule. 40 CFR 63, Subpart DDDDD - for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. Federal Register / Vol. 75, No. 107 / Friday, June 4, 2010.

[31] Attachment. Joint Motion by Applicant, TCEQ and Protestants to Remand Aspen Power Permit to TCEQ. Texas State Office of Administrative Hearings. October 20, 2009. Aspen Power Remand

[32] Telecom. Linero, A., Florida DEP and Liebman, Neil, CEO, Aspen Power. Status of Construction at Lufkin Generating Plant. July 26, 2010.

[33] Such NSPS related requests are now typically handled through a more involved process including a published EPA order in the Federal Register. At this time, the Department would not simply follow the previous NSPS action by EPA Region 4 as a binding precedent for a BACT determination.

[34] Report. C.E.M. Solutions. NO_X and CO Relative Accuracy Test Audit. USS Boiler No.8, December 4-5, 2009.

- During compliance testing, the VE observed by a contracted certified smoke reader was 0% opacity for all readings during the 1-hour test;[35]
- The observer noted the water droplets were not present in the USS Bagasse Boiler 8 stack exhaust;
- The observer noted the presence of a steam plume from the USS Bagasse Boilers Nos. 1, 2 and 4 that are controlled by scrubbers and not ESP;
- Discussion with plant personnel indicated that there is usually no visible plume from USS Boiler No. 8 except when burning oil;[36]
- Any plume from USS Boiler No. 8 typically has a slight tinge, less than 10% opacity and not associated with water vapor; and
- Discussion with Department compliance personnel confirms the observations of the plant personnel and the contractor.[37]

The Department concludes that any steam plume would form outside the stack if forms at all. The Department also concludes that moisture should not interfere with the function of a COMS.

Department's BACT Determinations $PM/PM_{10}/PM_{2.5}$ and VE. The Department will specify a PM/PM_{10} (f) limit of 0.01 lb/mmBtu. The applicant is authorized to install an ESP or fabric filter baghouse. A baghouse is preferable because it will provide better contact between sorbents and acid gases as well as between sorbents and Hg. The Department's proposal is equal to the BACT determination for the recently approved HEF cellulosic sorghum to ethanol and steam project.

A BACT VE standard of 10% opacity (6-minute average), except for one 6-minute period per hour of not more than 20% opacity, will also be established and demonstrated by a COMS.

The Department will establish a NH_3 limit of 10 ppm at 7% O_2 to minimize direct NH_3 emissions that can form ammoniated compounds (such as NH_4Cl and ammoniated sulfates) in the exhaust stream and in the environment. The limit will also provide reasonable assurance of proper control equipment operation. The NH_3 emission limit will be easily achieved by a SCR system and compliance shall be demonstrated by initial and annual tests using EPA Method CTM-027.

The Department has reviewed $PM_{2.5}$ and believes that measures have been incorporated into the Department's BACT determination for the project that will adequately address this pollutant. These measures include:

- BACT emission limits for $PM_{2.5}$ precursors including SO_2, NO_X, NH_3 and VOC:
- BACT emissions limits for $PM_{2.5}$ surrogates including PM_{10} and VE;
- The VE limit that directly controls the fraction of $PM_{2.5}$ that interferes with light transmission; and
- Limits on NH_3 and also on HCl as discussed further below.

4.3. HAP Emission Limits for the BFB Boiler

Refer to Table 5 in Section 3.5 above. The applicant estimated annual emissions of all HAP (aggregate) at 22.98 TPY from the project (18.77 TPY from the boiler) including 0.91 TPY of HCl and 0.03 TPY of HF. As previously discussed, the Department believes that HCl emissions (and certainly PTE) will be greater than estimated by the applicant such that (without further controls) aggregate HAP emissions will equal or exceed 25 TPY. With the additional BACT controls proposed by the Department and described above (SCR or ox-cat or both), it should be possible to reduce organic HAP emissions to compensate for the underestimated HCl and possibly HF emissions.

Because the PTE of the aggregate PTE of all HAP will be close to 25 TPY, it is necessary to establish emission limitations.

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[35] VE Test. Horton, Chuck. Record of Visual Determination of Opacity. USS Boiler No. 8. December 2, 2009.

[36] Telecom. Linero, A. and Tingleburg, K. Stack Plume Behavior for USS Boiler No. 8. August 31, 2010.

[37] Telecom. Linero, A., Heron, T. and Lewis, W. Stack Plume behavior for USS Boiler No. 8. September 7, 2010.

HCl Emissions

Although the applicant estimated 0.91 TPY, the Department will set a limit of 8.0 TPY of HCl on a 12-month rolling average, rolled monthly. The control method will be the same as previously discussed for SO_2 (i.e. removal by fly ash, the DSIS and the ESP or a fabric filter baghouse). Compliance shall be demonstrated by a HCl-CEMS.

The 12-month limit equates to approximately 1.9 lb HCl/hr. The limit, the DSIS, the ESP and the HCl-CEMS requirement will provide reasonable assurance that HCl emissions will be less than 10 TPY.

HF Emissions

Although the applicant estimated 0.03 TPY, the Department will set a limit of 4.0 TPY of HF on a 12-month rolling average, rolled monthly. The control method will be the same as previously discussed for SO_2 (i.e. removal by fly ash, the DSIS and the ESP or a fabric filter baghouse). Compliance shall be demonstrated by a HF-CEMS.

The 12-month limit equates to approximately 0.95 lb HF. The limit, the DSIS, the ESP and the HF-CEMS requirement will provide reasonable assurance that HF emissions will be less than 10 TPY.

Other HAP Emissions from the Boiler

The applicant estimates emissions of 0.99 TPY of metal HAP from the boiler (i.e. excluding the ethanol process) consisting primarily of Cr, Mn, Pb, Ni and, to a lesser degree, Hg. Total organic HAP and Cl_2 emissions from the boiler will equal approximately 13.87 and 2.66 TPY of organic HAP and Cl_2 respectively.

According to Table 5 in Section 3.5 above the applicant initially estimated Hg emissions of 0.022 TPY (44 lb/yr) and subsequently 3.3 lb/yr. The initial Hg emission factor developed by SRF was based on zero control. The original and subsequent estimates of Hg emissions (44 and 3.3 lb/yr) will not be included as emission limitations and are not BACT or MACT determinations.

Rather than setting individual limits for each of the categories of Cl_2,o rganic and metal HAP (including Hg) from the boiler, the Department will limit the total annual HAP emissions from the boiler to 20.0 TPY. This limit is expressed as $\sum$ (HCl, HF, Cl_2, metal HAP, organic HAP) = 20 TPY. This limit will complement the individual enforceable limits of 8.00 TPY limits for HCl and HF emissions.

The demonstration of compliance with 20.0 TPY limitation will be determined on a fiscal year basis, based on the initial and annual stack tests conducted for the identified metal and organic HAP stack tests coupled with the totalized HCl and HF-CEMS data for the given fiscal year. The HAP limit of 20 TPY from the boiler takes into consideration the applicant's separate estimate of 3.46 TPY of HAP from the ethanol process and 0.75 TPY of HAP as fugitive emissions. Further details regarding the ethanol process are given further below.

To achieve the NO_X and CO limits given above, the applicant may need to install a SCR system or an ox-cat system (or both). This will reduce organic HAP including D/F. If the applicant does not include a SCR system or an ox-cat system to control NO_X and CO, the Department requires installation of one or the other to provide reasonable assurance that facility-wide HAP emissions will be less than 25 TPY.

The total HAP estimate for the facility is 24.21 TPY. The Department has reasonable assurance that the facility (after controls) is not a major source of HAP because:

- The DSIS, H_2S scrubber and ESP (or a fabric filter baghouse) will control acid gases and metal HAP;
- HCl and HF emissions are limited to 8.0 and 4.0 TPY, respectively by enforceable conditions and required CEMS;
- Good combustion practices will minimize formation of organic HAP;

- A SCR system or an ox-cat system is required by the permit for the purpose of reducing organic HAP including D/F, if not already included by the applicant for the purpose of controlling NO_X and CO;
- There will be an annual HAP cap of 20 TPY from the boiler based on the HCl and HF-CEMS, and the required initial and annual Cl_2, metal and organic HAP tests;
- Further assurance is provided by the CO-CEMS as a surrogate for continuous low organic HAP emissions measurement from the boiler;
- Further assurance is provided by the low VE limit and COMS requirement:
- The VOC leak detection and repair (LDAR) described further below for the ethanol process pursuant to 40 CFR 60, Subpart VVa and ethanol process VOC BACT and required monitoring and testing requirements will minimize the contribution of HAP from the ethanol process to total project HAP emissions.

4.4. BACT Review for Cooling Tower (EU 003)

Discussion. The three cooling towers will be used for machine cooling, cooling the condensing set in the power block, and process cooling. Following are key characteristics of the cooling towers are listed in Table 8.

Table 8. Cooling Tower Characteristics. SRF Project

Cooling Tower	Cells No.	Height (ft)	Diameter (ft)	Dissolved Solids ppmw[1]	Water Flow (gpm)	Total Air Flow (acfm)[2]	$PM/PM_{10}/PM_{2.5}$ (TPY)
Machines	1	35	33	500	3,434	635,580	0.038/0.019/0.019
Power Block	3	35 ea.	33 ea.	500	17,962	4,449,060	0.20/0.10/0.10
Ethanol Process	3	35 ea,	33 ea.	500	9,774	4,131,270	0.11/0.054/0.054
Total	7	35 ea.	33 ea.	500	31,170	9,215,910	0.35/0.17/0.17

1. Parts per million by weight (ppmw)
2. Actual cubic feet per minute (acfm)

Cooling towers emit $PM/PM_{10}/PM_{2.5}$ based on the total dissolved solids (TDS) loading in the recirculating water. According to the applicant, the plant will use fresh water with a concentration TDS of only 500 ppmw. The applicant estimated $PM/PM_{10}/PM_{2.5}$ emissions at 0.35/0.17/0.17 TPY.

If not properly maintained and operated, the process and machines cooling towers may also emit VOC as a result of heat exchanger leaks and their subsequent stripping from the water stream by the air flow. SRF did not estimate VOC or organic HAP from the cooling towers presumably due to expected good operation and maintenance.

Applicant's proposal. The applicant proposes to install drift eliminators on the cooling towers to limit the cooling tower drift 0.001% of the water recirculation rate.

Department's Determination. Recent determinations by the Department limited the drift rate to 0.0005% of the water recirculation rate. Those determinations were for facilities using water characterized by much greater TDS concentrations. For example the basis for the HEF project was 2,750 ppmw. OUC used a value of 3,757 ppmw for the cooling tower on their Combined Cycle Unit B and Florida Power and Light (FP&L) used a value of 30,000 ppmw (maximum) for their Turkey Point Combined Cycle (Unit 5) project.

The applicant's TDS estimate of 500 ppmw TDS initially appeared to be very low. However, the Department accessed the key water use application and associated documents under review by the South Florida Water Management District (SFWMD).[38] The source of cooling tower makeup water will be via

[38] Permit Application. Aspring Sorghum Mill and Ethanol Facility. New Water Use. Application No. 100630-16.

any of the four wells proposed to be drilled into the Lower Tamiami Aquifer within Hendry County which is known for low TDS. It is at the bottom of the surficial aquifer system but is separated from the water table aquifer by confining beds and similarly separated by a confining unit from the sandstone aquifer within the intermediate aquifer systems and the Floridan Aquifer System. Direct discussion with the responsible geologist confirms the expectation of low TDS based on chloride concentrations on the order of 100 ppm.[39]

In view of the very low TDS value, the requested drift rate is acceptable at 0.001% together with a permit requirement recordkeeping requirement that can demonstrate that TDS of the incoming cooling makeup water is maintained less than or equal to 1,000 ppmw and that the source of cooling make up water is the Lower Tamiami Aquifer or water treated by a reverse osmosis plant.

The PM emission rate from the cooling tower is 0.35 TPY compared with the emission rate of 0.7 TPY for the HEF project (that has a lower drift rate but greater TDS). The FP&L Turkey Point project was estimated to emit more than 200 TPY of PM even at a drift rate of 0.0005%.

As required by NSPS Subpart VVa, the applicant submitted a preliminary Leak Detection and Repair (LDAR) Program plan. The Department will require expansion of the LDAR Program plan required for the facility pursuant to NSPA Subpart VVa to include the ethanol production process and machine cooling towers. The applicant will be required to collect a sample of cooling water from the towers on a weekly basis and analyze it for VOC. This will enable the early detection of leaking heat exchangers, thereby minimizing VOC emissions (including organic HAP) and odors. The applicant is required to submit a final LDAR Program plan, that includes the ethanol production process and machine cooling towers, to the Compliance Authority 90 days before the SRF facility becomes operational.

4.5. BACT Review for Ethanol Production Process (EU 004)

Discussion. The ethanol production process will result in the emissions of ethanol and other VOC such as acetic acid, lactic acid, and methanol (a HAP). These emissions will occur from the fermentation, distillation, and dehydration steps, as the ethanol is separated from the fermentation products. According to the applicant, there are two recognized, feasible means of controlling these emissions: wet scrubbing and thermal oxidation (TO) with each of these technologies capable of reducing VOC and HAP emissions by 98% or more.

The applicant further states that TO results in the destruction of the ethanol product and is disadvantageous compared with the wet scrubbing option. Also according to the applicant, a TO would require the combustion of additional fossil fuel leading to the emissions of criteria pollutants, such as VOC along with greenhouse gases (GHG). However, the Department also concludes that depending on conditions in the ethanol production process and VOC and HAP concentrations in the ethanol production process off gases, along with the type scrubbing liquid, wet scrubbing may not be as effect in destroying VOC and HAP as the applicant states. Consequently,th is emission unit may have trouble meeting permitted VOC and HAP emission limits[40].

Applicant's proposal. SRF proposes to use three wet scrubbers to control VOC and HAP emissions from the ethanol production process. The exhaust gases from all three scrubbers will exit to the atmosphere through a common wet scrubber stack which will have a design height of 25 ft, a design diameter of 4.9 ft with a flow rate of 4,223 ACFM and a temperature of 70 °F. Each scrubber will have a minimum 98% control efficiency. The wet scrubber controlling emissions from the fermentation step of the ethanol production process will use a hydro-alcoholic solution as the scrubbing media, whereas the other two scrubbers for the distillation and dehydration steps will utilize water. VOC emissions after control are estimated at 30.9 TPY from the fermentation scrubber; 1.21 TPY from the distillation scrubber; 10.2 TPY from the dehydration scrubber for a total of 42.3 TPY. Total HAP emissions from all three scrubbers are estimated to be 3.46 TPY.

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[39] *Telecom. Linero, A., DEP and Nancy Demonstrati, P.G., SFWMD. Permits under review by the SFWMD.*

[40] Nebraska Document goes here

Department's Review. The Department believes that TO can provide greater control than a wet scrubber, but reducing emissions by another 5-15 TPY would not likely be cost-effective for this emission unit. Furthermore, the Department agrees with the applicant that the combustion of additional fossil fuels as required by a TO would result in additional emissions of criteria pollutants. The Department accepts the wet scrubbers described by the applicant as BACT for this emissions unit with the following emission limits: VOC emissions through the wet scrubber stack shall not exceed 10.20 lb/hr (42.3 TPY); and total organic HAP emission through the wet scrubber stack shall not exceed 0.87 lb/hr (3.45 TPY). In addition, the Department establishes the following requirements:

- The applicant will have to comply with the Department's objectionable odor regulation Rule 62-296.320(2), F.A.C., which states: *"No person shall cause, suffer, allow or permit the discharge of air pollutants which cause or contribute to an objectionable odor"*. While the applicant may install wet scrubbers, the Department notes that the applicant would have to apply for a permit to install additional control equipment or inject reagents into the scrubbers to address objectionable odor problems.
- The Applicant would also have to apply for a permit to supplement or replace the wet scrubbers if this emission unit is unable to meet the VOC and HAP emission limits given above.

4.6. BACT Review for Bioreactors and Biogas Flare (EU 005)

Discussion. This emission unit consists primarily of a wastewater treatment anaerobic digester (bioreactor) to treat process wastewaters and to condition the resulting biogas for use as fuel in the biomass boiler. The biogas will provide 27.5 mmBtu/hr towards the 488 mmBtu/hr heat input (24 hour basis) of the biomass boiler. When the boiler is not in operation,th e biogas will be sent to a backup flare where it will be combusted.

The flare will be of the open type, which can be started immediately if the boiler must shut down. The effluent from the bioreactor will be discharged to an on-site pond system for recycling back to the plant or reused for irrigation. The maximum biogas throughput rate is 38,000 standard cubic feet per hour (scfm). The flare will operate a maximum of 720 hr/yr. The biogas will contain up to 2% of hydrogen sulfide (H_2S). According to the applicant, the emission unit will emit pollutants as indicated in the following table.

Table 9 – Annual Potential Emissions from Bioreactor and Backup Flare

Bioreactor + Backup Flare	Pollutants (TPY)					
	CO	NO_X	$PM/PM_{10}/PM_{2.5}$	SO_2	VOC	HAP
	0.41	0.35	0.13	0.91	5.0	0.0066

Applicant's Proposal. The applicant states that the bioreactor will be fixed roof tank and proposes as BACT to burn the biogas in the biomass boiler or the backup flare to control air emissions from the biogas. According to the applicant, combustion of the biogas in the boiler or the backup flare will provide a VOC control efficiency of 98% and will provide BACT level control for all pollutants except for SO_2. To control SO_2 emissions from the flare, the applicant proposes to install a wet scrubber to remove the H_2S prior to the gas being combusted in the flare. The wet scrubber will have a H_2S removal efficiency of 98%.

Department's Review. The combustion of the biogas in the biomass boiler or backup flare, along with a wet scrubber to remove H_2S prior to combustion, will provide BACT level treatment of all pollutants. As per the SO_2 BACT within Section 4.2 above, the wet scrubber must also be used to scrub the H_2S from the biogas prior to combustion in the biomass boiler. Combustion of the biogas in the boiler or backup flare will also control odor from this emission unit.

The Department accepts the procedures and equipment described by the applicant as BACT for this emissions unit. Compliance will be shown by meeting the biomass boiler emission limits given in Section 4.2 above when the boiler fires any amount of biogas. Also the backup flare when combusting biogas shall be operated with no VE except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. Finally, three samples of biogas entering (inlet) and exiting (outlet) the wet 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

4.7. BACT Review Storage Tanks (EU-006)

Discussion. The facility includes five volatile organic liquids (VOL) storage tanks subject to NSPS Subpart Kb: two ethanol tanks, one denaturant/gasoline tank; one second grade alcohol storage tank; one denaturant/gasoline tank; and one blend tank. Tank capacities range from 50,000 to 875,000 gallons. Ethanol and gasoline vapors will be the primary VOC emitted from these tanks.

The facility also includes five other VOL storage tanks not subject to NSPS Subpart Kb: the fusel tank with a capacity of 47,551 gallons; one nominal 2,642 gallon hydrated oil storage tank; one nominal 7,925 gallon metering tank; one nominal 2,642 gallon second grade storage tank; and one nominal 1,849 gallon fusel oil storage tank. Fusel oil has a very low pressure {~0.9 pounds per square inch atmosphere (psia)}, while the other tanks are not subject to Subpart Kb due to their size or the vapor pressure of the stored liquids. Emissions after control for all tanks storing VOL were estimated by the applicant to be.10.3 TPY of VOC.

The facility will also include the following storage tanks that do not store VOL:

- 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.
- 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.
- A nominal 5,000 gallon tank to store ULSD fuel oil for use in emergency equipment.
- 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.

Applicant's proposal. The applicant proposes to design the tanks subject to NSPS Subpart Kb with internal floating roofs to minimize VOC emissions. For the tanks not subject to Subpart Kb, the applicant proposes to use pressure relief valves/vapor condensers. The applicant asserts that it is no cost effective to fit these tanks with internal or external floating roofs, or to vent these tanks to a flare or vapor recovery unit.

Department's Review. The available control options for storage tanks include internal floating roofs, venting the storage tanks to a control device, and submerged pipe filling. Fixed roof tanks can be equipped with a pressure relief /vacuum conservation valves, which allow the tanks to operate at a slight internal pressure which prevents the release of vapors to the atmosphere during small changes in temperature, pressure, or liquid level.

The Department concurs with the applicant's selection of internal floating roofs on the tanks subject to Subpart Kb as BACT. Tanks containing volatile organic liquids but not subject to Subpart Kb shall use pressure relief valves/vapor condensers. The urea/ammonia and sulfuric acid storage tanks do not require BACT determinations.

4.8. BACT Review for Truck Rack Product Loadout and Flare (EU-007)

Discussion. The denaturant ethanol product (ethanol blended with gasoline) will be loaded onto tanker trucks at a rate of 600 gallons per minute using submerged fill. The maximum throughput product rate is 22,110,000 gal/yr of ethanol blended with 900, 000 gal/yr of gasoline. Vapors displaced from the trucks will be exhausted to a flare. The flare will be of the open type, which can be started immediately when the product loadout process starts. Ethanol and gasoline vapors will be the primary VOC emitted from the loading operation. These vapors will be controlled by combustion in the flare. The applicant estimates that emissions from the flare are: 0.0091 TPY SO_2; 1.04 TPY NO_X; 5.4 TPY CO; 0.052 $PM/PM_{10}/PM_{2.5}$ and 2.13 TPY of VOC. Total VOC and HAP emissions from the flare and the loadout process were estimated by the applicant to be estimated to be 5.10 TPY of VOC and 0.16 TPY of HAP.

Applicant's proposal. The applicant proposes to divert the VOC vapors displaced from the tanker trucks during product loadout to a flare. The product loadout Flare will have a rated capacity of 9.8 MMBtu/hr and will provide 98% control efficiency for VOC vapors during the loading of the tanker trucks.

Department's Review. The available control alternatives for this process include flares and TO. The selection of a flare is appropriate as BACT for this emissions unit.

4.9. BACT Review for Miscellaneous Dry Material Storage Silos (EU 008)

Discussion. The materials stored in these silos include one to store the sorbent used in the DSIS, one for lime used in the water treatment system, and one for limestone for use in the bed of the BFB biomass boiler (if used). The silos will emit small amounts of $PM/PM_{10}/PM_{2.5}$ with the applicant estimating the total to be 0.036 TPY.

Applicant's proposal. The applicant proposes to control $PM/PM_{10}/PM_{2.5}$ emissions from the miscellaneous dry material storage silos by standard type bin vent filters. These are passive control devices that do not have a fan. When the silos are pneumatically loaded from trucks, the conveying air must exit the silo through the bin vent filter. These filters will control dust emissions in the exhaust gas to a concentration of 0.01 grains per dry standard cubic foot (gr PM/dscf). These storage silos will each have a standard type bin vent filter to control dust emissions.

Department's review. The Department concurs with the applicant's proposal for BACT. The Department also establishes that VE from the each bin vent filter during material loading shall not exceed 5% opacity as demonstrated by initial and annual compliance tests. A VE emission reading of 5% opacity or less may be used to establish compliance with the 0.01 gr/dscf PM/PM_{10} standard. A visible emission reading greater than 5% opacity will require the permittee to perform a PM/PM_{10} emissions stack test on the bin vent filter within 60 days to show compliance with the PM limit.

4.10. BACT Review for Emergency Generators (EU 009)

Discussion. 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.

Applicant's Proposal. The applicant proposes to use ULSD fuel oil or propane (1.5 gr SO_2/100 ft^3) and to comply with the requirements of NSPS Subpart IIII.

Table 10 - Emission Standards for Emergency Generators

Emergency Generator (> 560 kW and ≤ 2,237 kW)	**CO** (g/kWH)[a]	**VOC** (g/kWH)	**NO_X** (g/kWH)	**PM** (g/kWH)	**SO_2**[c] (oil S spec.)
Subpart IIII (2006 and later)	3.5	6.4 (NMHC[b] + NO_X)		0.20	0.0015%

a. g/kWH means grams per kilowatt-hour.
b. NMHC is the acronym for non-methane hydrocarbons. NMHC are approximately equal to VOC for these sources.
c. Subpart IIII references 40 CFR 80.510, which specifies 0.05% S until October 1, 2010 and 0.0015% S thereafter.

Department's Review. The applicable Subpart IIII has been updated in recent years and includes progressively more stringent requirements based on the model year of the engine selected. The Subpart IIII values in the table above given for engines for model year 2006 and beyond are appropriate as BACT for this type of engine, service and hours of operation. By complying with Subpart IIII, compliance is attained for Subpart ZZZZ. The limits on NMHC are sufficient to regulate VOC.

The Department accepts the applicant's BACT proposal for this emission unit with the added condition that the duration of any one maintenance action or test is limited to no more than 30 consecutive minutes.

4.11. BACT Review for Emergency Fire Pump Engine (EU 010)

Discussion.

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.

Applicant's Proposal.

The applicant proposes to use ULSD fuel oil or propane and to comply with the requirements of NSPS Subpart IIII. By complying with Subpart IIII, compliance is attained for Subpart ZZZZ.

Table 11 - Emission Standards for Emergency Fire Pump Engines

Emergency Pumps (≥ 300 hp and < 600 hp)	**VOC** (g/hp-hr)	**NO_X** (g/hp-hr)	**PM** (g/hp-hr)	**CO** (g/hp-hr)	**SO_2**[a] (oil S spec.)
Subpart IIII	3.0 (NMHC+NO_X)		0.15	2.6	0.0015%

a. g/hp-hr means grams per horsepower-hour.
b. Subpart IIII references 40 CFR 80.510, which specifies 0.05% S until October 1, 2010, after which it specifies 0.0015% S.

Department's Review. The Subpart IIII values in the table above given for engines for model year 2009 and beyond are appropriate as BACT for this type of engine,se rvice and limited hours of operation. The limits on NMHC are sufficient to regulate VOC and to control CO emissions to an acceptable degree (0.5 TPY).

The Department accepts the applicant's BACT proposal for this EU, The Department accepts the applicant's BACT proposal for this emission unit with the added condition that the duration of any one maintenance action or test is limited to 30 consecutive minutes.

4.12. BACT Review for VOC Fugitive Equipment Leaks (EU 011)

Discussion. Uncontrolled leaks from equipment such as from pumps, compressors, relief devices, flanges, valves, etc. can be significant sources of VOC and HAP emissions. This equipment is part of several of the emission units associated with this project. Because the SRF project is a SOCMI facility, it is subject to NSPS Subpart VVa - Equipment Leaks in the Synthetic Organic Chemical Manufacturing Industry (for projects that commence construction or modifications after November 7, 2006). Subpart VVa has specific requirement for controlling such leaks from pumps, compressors, relief devices, flanges, valves, etc. One requirement is the development of a Leak Detection and Repair (LDAR) program to insure compliance with VVa and any other requirements to control equipment leaks. The VOC emissions from the following other emission units at the proposed SRF facility also fall under EU-012:

- 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.

Applicant's Proposal. The applicant proposes a LDAR program and compliance with the requirements of Subpart VVa as BACT for this emission unit. The applicant has submitted a preliminary LDAR program plan and will submit a final plan prior to the SRF facility becoming operational.

Department's Review. Subpart VVa is a comprehensive requirement. Together with the LDAR program, Subpart VVa will complement the BACT determinations for each process emission unit that is a source of VOC and possibly odor. The Department accepts the applicant's proposal as BACT and will include a requirement to submit the details of a site-specific LDAR program pursuant to Subpart VVa no later than 90 days before the SRF becomes operational. In addition, 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. Finally, per Subpart VVa, SRF must demonstrate compliance with NSPS, Subpart VVA no later than 180 days after the initial startup of the SRF facility.

4.13. Odor Considerations

Discussion. In previous sections, reference was made to Rule 62-296.320(2), F.A.C., which states: "no person shall cause, suffer, allow or permit the discharge of air pollutants which cause or contribute to an objectionable odor". However, even with control measures, conventional grain ethanol plants are often associated with odors. The most important odor source in a conventional grain ethanol plant is from the residual grain material after fermentation and separation of the ethanol. The potential for odor from an ethanol plant utilizing sweet sorghum as its feedstock is probably less than a corn feedstock based facility. Still odor is a concern and must be addressed.

Applicant's Proposal. The applicant proposes the following measures to control VOC and odors at the SRF facility:

- Just-in-time delivery of ethanol process feedstock biomass;
- Wet scrubbers to control water-soluble VOC from hydrolysis, fermentation and distillation steps;
- Floating roofs on product storage tanks;
- Flares to control emissions from product load out and the biogas (if not used as fuel) produced by the anaerobic digestion step in wastewater treatment;
- Use enclosed vessels for the anaerobic digestion step rather than lagoons;
- Maintaining only small storage piles of supplemental (wood chips, yard waste and harvest residue) to minimize odors;
- Prompt repair of any leaking components (such as heat exchangers) within the cooling towers to minimize contamination of the water by and subsequent stripping of VOC to the atmosphere; and
- As per NSPS 40 CFR 60, Subpart VVa, SRF will implement a LDAR program to minimize VOC emissions from process equipment leaks. This will address a significant portion of the odor potential.

Department's Review. The Department agrees that the VOC control measures proposed by the applicant at SRF will reduce the generation potential for objectionable odors. However it is important to reiterate that objectionable odors are actually *prohibited.* The relevant rule states:

"No person shall cause, suffer, allow or permit the discharge of air pollutants which cause or contribute to an objectionable odor. 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."

The Department will require that SRF shall submit an odor control plan (OCP) early in the design process that describes procedures to be implemented if objectionable odors occur. The OCP must be submitted to the Compliance Authority no later than 90 days prior to SRF commencing operation.

5. BIOMASS BOILER HEAT INPUT MONITORING

Monitoring of heat input is difficult when using biomass as fuel. Sweet sorghum bagasse can have a high moisture content (50%) compared to other fuels proposed for the biomass boiler and boiler energy will be expended to evaporate that moisture thus reducing the boiler efficiency. In the case of biogas, the boiler will operate at a higher efficiency.

To accurately calculate heat input the Department will require the following methodology:

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 bagasse and field residue 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. 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 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.

Boiler Heat Input Rate Calculation: 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. This procedure shall be used to calculate the heat input rate in mmBtu/hr to the biomass boiler when using sweet sorghum bagasse as the primary fuel and biogas as a supplemental fuel, wood/sorghum trash as the primary fuels with biogas as a supplemental fuel and ULSD fuel oil or propane as a bed stabilization fuel. In lieu of the method given in Appendix F, the American Society of Mechanical Engineers (ASME) Form for Abbreviated Efficiency Test shall be used with prior approval of the Compliance Authority.

6. AIR QUALITY IMPACT ANALYSIS

6.1. Introduction

The proposed project will increase emissions of the following PSD-pollutants at levels in excess of the respective PSD significant emission rates: $PM/PM_{10}/PM_{2.5}$, SO_2, VOC, CO, and NO_X. For these pollutants the applicant must provide a demonstration using approved air quality models that project emissions will not cause or contribute to a violation of an ambient air quality standard (AAQS) or PSD increment for the pollutants where they apply. Of these pollutants, PM_{10}, $PM_{2.5}$, SO_2, CO, and NO_X (as NO_2) have defined national and state AAQS, and the pollutants PM_{10}, SO_2, and NO_2 have defined PSD increments. In addition, significant impact levels (SIL) and de minimis monitoring levels are defined for these pollutants and are used to determine the scope of the modeling analysis and the need for additional ambient air monitoring data.

At this time, $PM_{2.5}$ increments, SIL, and de minimus monitoring levels have not been adopted into Florida rules. NO_2 and SO_2 SIL and de minimis monitoring levels for the 1-hour standard have not been formerly proposed, but the U.S. EPA has provided interim guidance on 1-hour NO_2 and SO_2 SIL until a formal proposal is made. There are no applicable PSD increments, AAQS, significant impact or de minimis monitoring levels for VOC.

6.2. Major Stationary Sources Near the Proposed SRF Sorghum-to-Ethanol Advanced Biorefinery

To provide some perspective on the relative scale of the proposed project, the following tables list the largest stationary sources, by pollutant, in and around Hendry County. The maximum expected future emissions in TPY from the proposed project are also shown for comparison.

Table 12 - Largest Sources of SO_2 (2009) in Counties near the Proposed Plant (TPY)

Owner/Company Name	Site Name	County	Emissions
FP&L	Martin Power Plant	Martin	6,502
FP&L	Port Everglades Power Plant	Broward	5,385
Indiantown Cogeneration Plant	Indiantown Cogeneration Plant	Martin	1,767
Waste Management Inc	Gulf Coast Sanitary Landfill	Lee	634
FP&L	Riviera Power Plant	Palm Beach	445
Sugar Cane Growers Co-Op (SCGC)	Sugar Cane Growers Co-Op	Palm Beach	441
Waste Management Inc	Central Disposal of Pompano Beach	Broward	376
New Hope Power Company (NHPC)	Okeelanta Cogeneration Plant	Palm Beach	202
Southeast Renewable Fuels (SRF)	**SRF Sorghum to Ethanol**	**Hendry**	**161**
U.S. Sugar Corporation (USSC)	USSC Clewiston Mill & Refinery	Hendry	157
Wheelabrator North Broward, Inc	Wheelabrator North Broward	Broward	142
United Technologies Corp. (UTC)	UTC/Pratt Whitney ACFT	Palm Beach	117
Palm Beach County (PBC)	PBC Utilities Water Reclamation	Palm Beach	108

Table 13 - Largest Sources of NO_X (2009) in Counties near the Proposed Plant (TPY)

Owner/Company Name	Site Name	County	Emission
FP&L	Martin Power Plant	Martin	4,606
FP&L	Port Everglades Power Plant	Broward	4,018
FP&L	Ft. Lauderdale Power Plant	Broward	2,371
Wheelabrator North Broward, Inc	Wheelabrator North Broward	Broward	1,344
Wheelabrator South Broward, Inc	Wheelabrator South Broward	Broward	1,340
PBC Solid Waste Authority (SWA)	PBC Solid Waste Authority (SWA)	Palm Beach	1,330
Indiantown Cogeneration Plant	Indiantown Cogeneration Plant	Martin	1,301
FP&L	Fort Myers Power Plant	Lee	1,002
USSC	USSC Clewiston Mill & Refinery	Hendry	808
New Hope Power Company	Okeelanta Cogeneration Plant	Palm Beach	801
Lee County	Lee County WTE Facility	Lee	699
Sugar Cane Growers Co-Op	Sugar Cane Growers Co-Op	Palm Beach	475
Osceola Farms	Osceola Farms	Palm Beach	364
SRF	**SRF Sorghum to Ethanol**	**Hendry**	**247**
FP&L	West County Energy Center	Palm Beach	170

Table 14 - Largest Sources of CO (2009) in Counties near the Proposed Plant (TPY)

Owner/Company Name	Site Name	County	Emission
USSC	USSC Clewiston Mill And Refinery	Hendry	11,074
SCGC	Sugar Cane Growers Co-Op	Palm Beach	9,533
FP&L	Martin Power Plant	Martin	1,673
New Hope Power Company	Okeelanta Cogeneration Plant	Palm Beach	1,598
FP&L	Port Everglades Power Plant	Broward	790
SRF	**SRF Sorghum to Ethanol**	**Hendry**	**684**
Southern Gardens Citrus (SGC)	Southern Gardens Citrus Processing	Hendry	571
Waste Management Inc. (WMI)	Central Disposal	Broward	289
FP&L	Ft. Lauderdale Power Plant	Broward	237

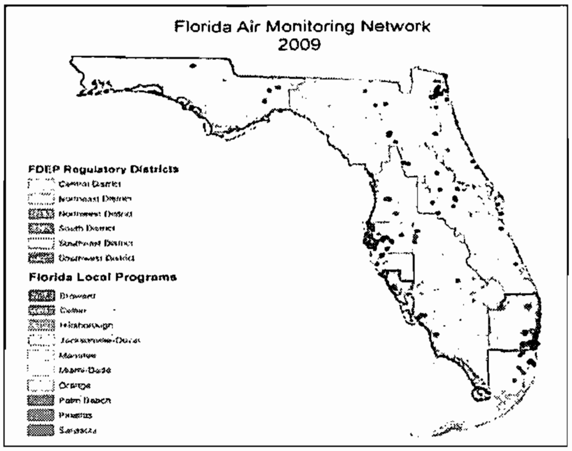
Table 15 - Largest Sources of PM_{10} (2009) in Counties near to the Proposed Plant (TPY)

Owner/Company Name	Site Name	County	Emission
FP&L	Martin Power Plant	Martin	746
USSC	USS Clewiston Mill And Refinery	Hendry	267
SCGC	Sugar Cane Growers Co-Op	Palm Beach	218
FP&L	Fort Myers Power Plant	Lee	215
FP&L	Ft. Lauderdale Power Plant	Broward	139
FP&L	West County Energy Center	Palm Beach	98
NHPC	Okeelanta Cogeneration Plant	Palm Beach	85
FP&L	Port Everglades Power Plant	Broward	71
SRF	**SRF Sorghum to Ethanol**	**Hendry**	**46**
SGC	Southern Gardens Citrus Processing	Hendry	26
FP&L	Riviera Power Plant	Palm Beach	11

6.3. Ambient Air Monitoring Surrounding Proposed Facility

The State ambient air monitoring network operated by the Department and its partners (local air pollution control programs) includes monitors in counties containing over 90% of the population. As Figure 21 indicates, the ambient air monitoring sites are concentrated in areas of high population density, along the coasts and near major highways in the interior portion of the state.

The Florida Sugar Cane League (FSCL) operates a PM_{10} monitoring site in Clewiston, Hendry as well as SO_2 and ozone instruments in Belle Glade, Palm Beach County. The Palm Beach County Public Health Unit operates six monitoring sites for the measurement of SO_2, NO_2, $PM_{10}/PM_{2.5}$ and ozone as shown in Figure 22.



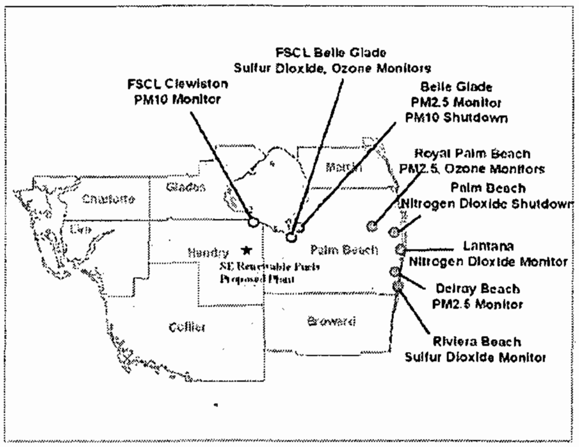


Figure 21 – Air Monitoring Network **Figure 22. Monitors in Hendry and Palm Beach Counties**

These monitors are used to estimate the existing air quality in the area of the proposed facility. The monitors in Clewiston and Belle Glade are nearest and most representative of the proposed site. The monitors along the more populated areas of the Palm Beach County coast provide conservative (i.e., higher) estimates of pollutant concentrations for the area of the proposed facility due to the proximity of urban air pollution sources. Air quality measurements from these monitors are summarized in Table 16.

Table 16 - Ambient Air Quality Measurements Nearest to the Project Site (2007-2009)

Pollutant	Location (Site Number)	Averaging Period	Ambient Concentration			
			Compliance Period	Value	Standard	Units [a]
PM_{10}	Belle Glade (0990008)	24-hour [b]	2008	49	150	$\mu g/m^3$
		Annual [c]	2008	18.9	50	$\mu g/m^3$
$PM_{2.5}$	Belle Glade (0990008)	24-hour [d]	2007-2009	15	35	$\mu g/m^3$
		Annual [e]	2007-2009	6.3	15	$\mu g/m^3$
SO_2	FSCL Belle Glade (0992101)	1-hour [i]	2009	3	75	ppb
		3-hour [f]	2009	5.5	1300	$\mu g/m^3$
		24-hour [f]	2009	5.5	260	$\mu g/m^3$
		Annual [c]	2007-2009	2.6	60	$\mu g/m^3$
NO_2	Palm Beach (0990020)	Annual [c]	2006-2008	8	53	ppb
		1-hour [h]	2008	41	100	ppb
CO	WPB Lantana (0991004)	1-hour [f]	2007	2	35	ppm
		8-hour [g]	2009	1	9	ppm
Ozone	Royal Palm Beach (0990009)	8-hour [g]	2009	0.065	0.075	ppm

a. Units are in: micrograms per cubic meter ($\mu g/m^3$); parts per billion (ppb); or parts per million (ppm).
b. Not to be exceeded on more than an average of one day per year over a three-year period.
c. Arithmetic mean.
d. Three year average of the 98th percentile of maximum daily 24-hour concentrations with exceptional events excluded (as approved by EPA).
e. Three year average of the arithmetic annual means with exceptional events excluded (per EPA).
f. Not to be exceeded more than once per year.
g. Three year average of the annual 4th highest daily 8-hour maximum.
h. Three-year average of the annual 98th percentile maximum daily 1-hour value
i. Three-year average of the annual 99th percentile maximum daily 1-hour value

6.4. Existing Ambient Air Quality Near Project Site – $PM_{2.5}$ and Ozone

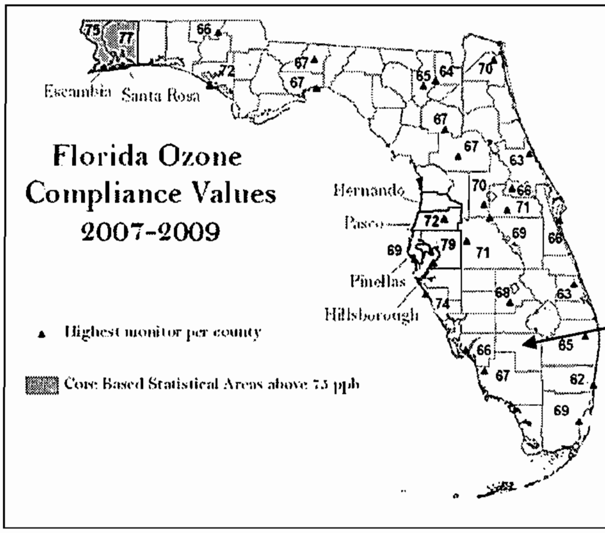
Ozone is a key indicator of the overall state of regional air quality. It is not emitted directly from combustion processes. Rather it is formed from VOC and NO_X emitted primarily from regional industrial and transportation sources. VOC is also emitted from authorized agricultural fires, natural drought-related fires and natural emissions from vegetation. These two precursors participate in photochemical reactions that occur on an area-wide basis and are highly dependent on meteorological factors.

Ozone limits and measurements in Table 16 are summarized on three year blocks, rolled annually. The reported ozone value was calculated by taking the maximum 8-hour readings recorded each day during the three years. The fourth highest of the recorded maxima were identified for each year and then the average of those three values was reported as the compliance value given in Table 16 and Figure 23.

$PM_{2.5}$ (also known as PM_{fine}) is another key indicator of the overall state of regional air quality. Some $PM_{2.5}$ is directly emitted as a product of combustion from transportation and industrial sources as well as fires. Much of it consists of particulate nitrates and sulfates formed through chemical reactions between gaseous precursors such as SO_2 and NO_X from combustion sources and ammonia (NH_3) naturally present in the air or added by other industrial sources.

$PM_{2.5}$ limits and measurements are summarized on three-year blocks, rolled annually. The reported 24-hour compliance value for $PM_{2.5}$ is 15 $\mu g/m^3$ as indicated in Table 16 for the Belle Glade site, and was calculated by taking the average 24-hour readings recorded each day during the three years (2007-2009). The value for each year that exceeds 98% of all daily measurements within each given year was identified and then the average of those three numbers was reported as the 24-hour compliance value and compared with the standard of 35 $\mu g/m^3$.

The simple average of all $PM_{2.5}$ measurements within each three years (2007-2009) was also calculated and then the mean of the three averages (6.3 $\mu g/m^3$) was reported as the annual compliance value and compared with the standard of 15 $\mu g/m^3$. Comparisons of the 24-hour and annual $PM_{2.5}$ compliance values for the Belle Glade station are shown in Figure 24 along with compliance values for the rest of the state.



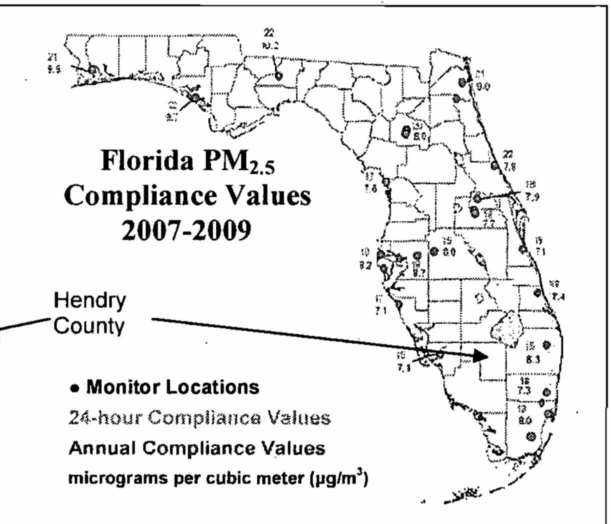


Figure 23 – Florida Ozone Compliance Values **Figure 24 – Florida $PM_{2.5}$ Compliance Values**

The results indicate that adjacent Palm Beach County (including the monitoring sites nearest to Hendry County) is in attainment with the applicable ozone and $PM_{2.5}$ AAQS. The Palm Beach County results coupled with those from other nearby counties shown in Figures 23 and 24 suggest that Hendry County is in attainment for both pollutants.

6.5. <u>$PM_{2.5}$ Precursor Emissions from Power Plants in the Southeastern U.S.</u>

There is a regional effort underway through the CAIR and other regulatory programs to reduce emissions of $PM_{2.5}$ precursors including NO_X (also an ozone precursor) and SO_2. Regional SO_2 emission reductions from existing power plants between 2007 and 2009 are listed in Table 17. SO_2 emissions from power plants in Florida were reduced by nearly 120,000 TPY and regional SO_2 emissions were reduced by over 1.25 million TPY.

The state and regional SO_2 reduction trends will continue as coal-fueled power plants continue to install scrubbers to control SO_2 emissions. Regional NO_X emission reductions from existing power plants between 2007 and 2009 are listed in Table 18.

NO_X emissions from power plants in Florida were reduced by nearly 100,000 TPY and regional NO_X emissions were reduced by well over 460,000 TPY. The state and regional NO_X reduction trends will continue as coal-fueled power plants operators throughout the southeastern states continue to install SCR systems to control NO_X.

Table 17 - SO_2 Emission Reductions from Power Plants in the Southeast between 2007 and 2009

State	2007 (TPY)	2009 (TPY)	Reduction (TPY)	Reduction (%)
Alabama	447,189	277,971	169,218	38
Florida	317,582	197,682	119,900	38
Georgia	635,484	262,258	373,226	59
Kentucky	379,837	252,001	127,836	34
Mississippi	69,796	40,160	29,636	43
North Carolina	370,826	110,948	259,878	70
South Carolina	172,726	97,940	74,786	43
Tennessee	237,231	108,042	129,189	12
Total	**2,630,671**	**1,347,002**	**1,283,669**	**49**

Table 18 - NO_X Emission Reductions from Power Plants in the Southeast between 2007 and 2009

State	2007 (TPY)	2009 (TPY)	Reduction (TPY)	Reduction (%)
Alabama	122,374	49,610	72,764	59
Florida	184,171	84,252	99,919	54
Georgia	107,471	57,566	49,905	46
Kentucky	174,840	78,767	96,073	55
Mississippi	48,546	26,601	21,945	45
North Carolina	59,417	38,782	20,635	35
South Carolina	46,062	21,213	24,849	54
Tennessee	102,886	27,911	74,975	73
Total	**845,767**	**384,702**	**461,065**	**55**

6.6. SO_2 and NO_X Emission Trends from FPL Peninsular facilities

Per Tables 12 and 13 above, FP&L facilities are the largest sources of SO_2 and NO_X (precursors of $PM_{2.5}$ and/or ozone) nearest to the proposed SRF site. To put emissions from the existing FP&L facilities and the future SRF into another perspective, the Department graphed the SO_2 and NO_X emission trends during the period 1998-2009 from FPL fossil-fueled plants located in the Florida peninsula. Most of the plants are in South Florida. The data source is the EPA Clean Markets Acid Rain database. The results are summarized in Figure 25.

During the period 1998-2009 there was a *decrease* from 221,400 to 24,700 TPY (89%) in SO_2 emissions from the FP&L fossil fleet in peninsular Florida. Similarly there was a *decrease* from 98,500 to 20,500 TPY (79%) in NO_X emissions. For comparison purposes, the future SRF will emit 161 TPY of SO_2 and 247 TPY of NO_X.

The contribution of 161 TPY of SO_2 and 247 TPY of NO_X from the SRF will not affect the general, overwhelming and continuing downward trend in $PM_{2.5}$ precursors. Similarly, it will not have an appreciable effect on local or regional $PM_{2.5}$ concentrations.

6.7. Ambient $PM_{2.5}$ Trends in South Florida

The overall reduction in $PM_{2.5}$ precursor emissions from stationary sources and the transportation sources (due to use of cleaner fuels) has contributed to the clear decline in ambient $PM_{2.5}$ levels in South Florida during the same period as shown in Figure 26. Basically the pronounced reductions in Miami are consistent with the mentioned reductions in emissions from stationary and transportation sources. By and large, the values in Belle Glade (within the rural sugar cane growing area) have been the lowest. However, they have been more resistant to further declines most likely due to the nature of the sugar industry which is based on periodic burning followed by harvesting of sugar cane.

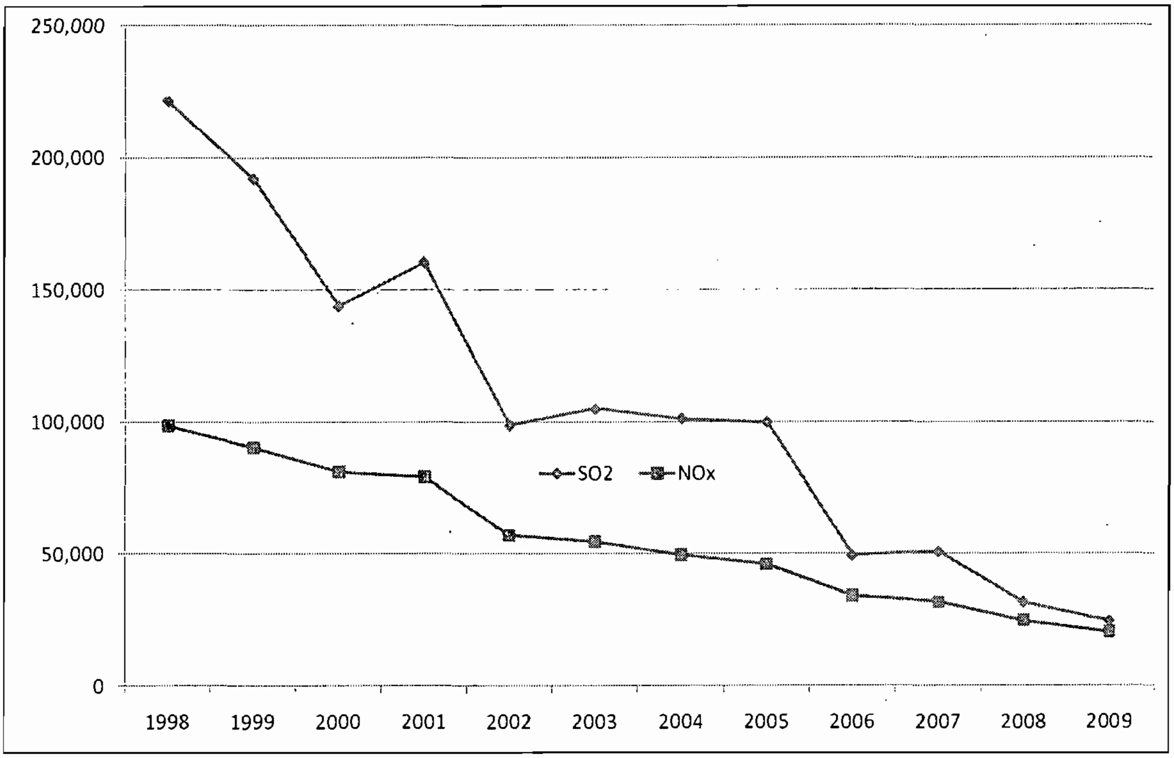


Figure 25 – SO_2 and NO_X reductions in TPY at FPL Peninsular Facilities (1998-2009)

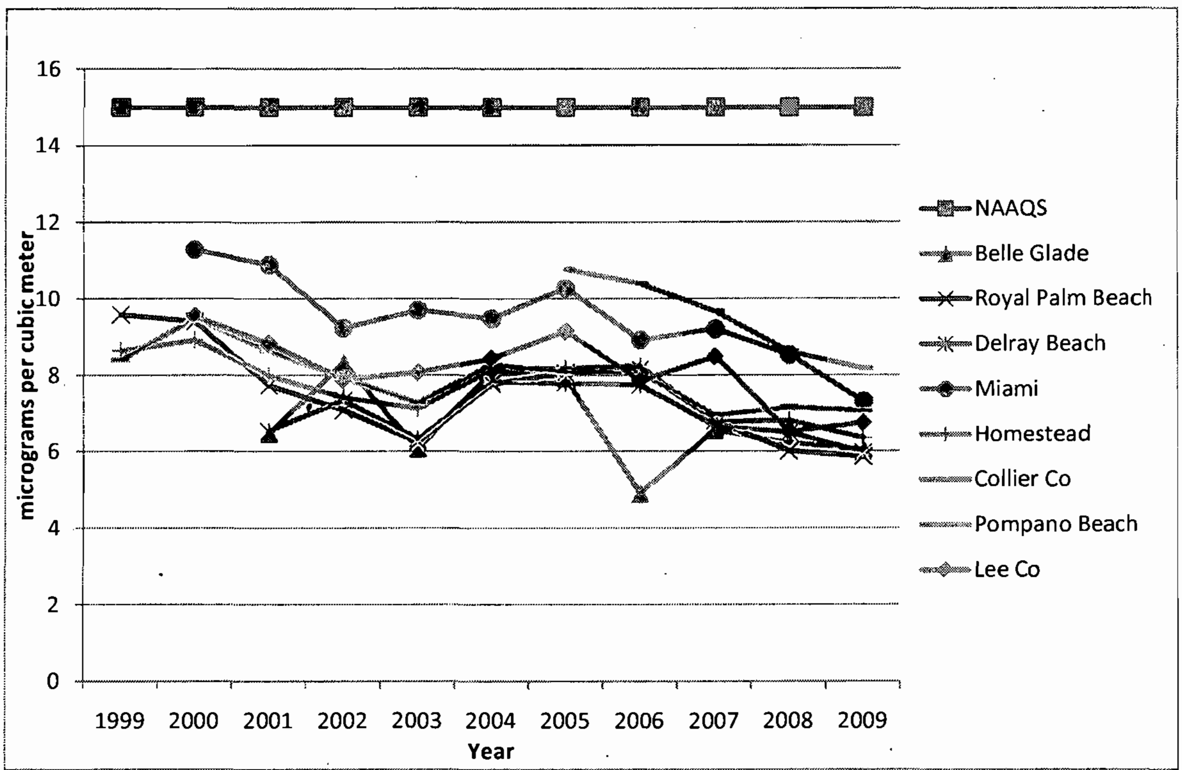


Figure 26. South Florida Annual Average $PM_{2.5}$ Trends (1999 – 2009)

6.8. Air Quality Impact Analysis

Significant Impact Analysis

Significant Impact Levels (SIL) are defined for PM/PM_{10}, CO, NO_X and SO_2. A significant impact analysis is performed on each of these pollutants to determine if a project can cause an increase in ground level concentration greater than the SIL for each pollutant.

The EPA-approved CALPUFF modeling system was used by the applicant to address the significant impact on the PSD Class I area (Everglades National Park) with respect to the more restrictive Class I significance levels. The applicant used SIL recently established by the EPA for $PM_{2.5}$. In the case of NO_2 (1-hour) and SO_2 (1-hour), the EPA has not yet proposed SIL. The applicant used a SIL value equal to 4% of the NAAQS for the latter two pollutants based on:

- The 4% SIL is more conservative (less than) the 5% SIL applicable to the only other pollutant (CO) that has a 1-hour averaging time [Rule 62-204.200(29), F.A.C.];
- The 4% SIL will capture all sources (regardless of size) within 3 km of SRF;
- The applicant also included all sources greater than 10 TPY within 53 km of SRF;
- The applicant included all sources greater than 1,000 TPY within 100 km of SRF.

The applicant believes this approach encompasses all meaningful SO_2 and NO_X sources capable of interacting with SRF for the purposes of determining impacts with respect to the 1-hour SO_2 and NO_2 NAAQS.

In order to conduct a significant impact analysis, the applicant has used the proposed project's maximum short-term emissions as inputs to the models. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate SIL for the PSD Class I and Class II Areas.

If this modeling for a particular pollutant shows ground-level increases less than its SIL, the applicant is exempted from conducting any further modeling. If the modeled concentrations from the project exceed the SIL, then additional modeling including emissions from all major facilities or projects in the region (multi-source modeling) is required to determine the proposed project's impacts compared to the AAQS and PSD increments for those pollutants.

The results of the applicant's significant impact analysis are shown below in Tables 19 and 20. Maximum predicted impacts are greater than the applicable SIL for the Class II area for PM_{10}, $PM_{2.5}$, SO_2, and NO_2, with the exception of the NO_2 and SO_2 annual averaging times. Consequently, a full AAQS analysis (in which the PSD Increment analysis considering all sources of these pollutants in the area) is required.

For the Class I analysis in the Everglades National Park, located 85 km from the project site, the maximum predicted impacts of due to the SRF project only are all predicted to be less than the proposed PSD Class I significant impact levels for all pollutants (PM_{10}, $PM_{2.5}$, SO_2, NO_2, and CO) and averaging periods. Thus, no further analysis is required.

Table 19 - Maximum Predicted Air Quality Impacts from the SRF Project for Comparison to the PSD Class II SIL

Pollutant	Averaging Time	Max Predicted Impact [a] ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Ambient Air Standards ($\mu g/m^3$)	Significant Impact?	Max Distance of Sig. Impact (km)
PM_{10}	Annual	9.0	1	50	Yes	0.9
	24-Hour	28.5	5	150	Yes	2.9
$PM_{2.5}$	Annual	1.3	0.3 [d]	15	Yes	0.9
	24-Hour	12.7	1.2 [d]	35	Yes	4.4
SO_2	Annual	0.4	1	60	No	-
	24-Hour	13.9	5	260	Yes	1.1
	3-hour	51.6	25	1300	Yes	0.7
	1-hour	87.2	7.9 [b]	196	Yes	3.1
NO_2 [c]	Annual	0.8	1	100	No	-
	1-Hour	32.9	7.6 [b]	189	Yes	2.6
CO	1-hour	348.4	2,000	40,000	No	-
	8-hour	239.2	500	10,000	No	-

a. Results based on the maximum impacts of either the boiler and truck flare operation or the biogas flare and truck flare operation.
b. Applicant's project SIL.
c. Assumes 100% conversion of NO_X to NO_2, i.e., the tier 1 modeling approach.
d. Final SIL for $PM_{2.5}$ was established by EPA on September 29, 2010.

Table 20 - Maximum Air Quality Impacts from the SRF Project for Comparison to the PSD Class I SIL for 2001 - 2003

Pollutant	Averaging Time	Max. Predicted Impact ($\mu g/m^3$)	Class I SIL ($\mu g/m^3$)	Significant Impact?
PM_{10}	Annual	0.0004	0.2	No
	24-hour	0.012	0.3	No
$PM_{2.5}$	Annual	0.0004 (as PM_{10})	0.04 [a]	No
	24-hour	0.012 (as PM_{10})	0.07 [a]	No
NO_2	Annual	0.0026	0.1	No
SO_2	Annual	0.0022	0.1	No
	24-hour	0.11	0.2	No
	3-hour	0.37	1	No

a. Based on the lowest proposed concentration level from options in the proposed EPA rules for $PM_{2.5}$ SIL.

Preconstruction Ambient Monitoring Requirements

A preconstruction monitoring analysis is performed for those pollutants with listed significant monitoring concentrations (de minimus levels). These are levels, which, if exceeded, would potentially require pre-construction ambient monitoring. As shown in Table 21 below, the maximum predicted impacts due to the proposed project only are predicted to be below the PSD de minimis concentration levels for NO_2 and CO, but above the de minimis concentration levels for PM_{10}, $PM_{2.5}$, and SO_2.

Table 21 - Maximum Air Quality Impacts for Comparison to the De Minimis Concentration Levels

Pollutant	Averaging Time	Max Predicted Impact ($\mu g/m^3$)	De Minimis Level ($\mu g/m^3$)	Impact Greater Than De Minimis?
PM_{10}	24-hour	28.5	10	Yes
$PM_{2.5}$	24-hour	12.7	4	Yes
NO_2	Annual	0.8	14	No
SO_2	24-hour	87.2	13	Yes
CO	8-hour	239.2	575	No

As discussed in Section 6.3, existing monitoring in the area of the project is described. These data are deemed to be either representative of the site or sufficiently conservative to satisfy preconstruction monitoring needs. Thus, while predicted concentrations are greater than de minimis, no additional site-specific monitoring is being required.

Models, Emissions Data, and Meteorological Data Used in the AAQS and PSD Increments Analysis

PSD Class I Area: The CALPUFF model (version 5.8, i.e., current EPA-approved version for regulatory use) was used for the Class I air quality analysis. The CALPUFF model is a long-range transport model applicable for estimating the air quality impacts in areas that are more than 50 km from a source. Since the entire Everglades National Park (ENP) PSD Class I area is beyond 50 km from the projected site, the CALPUFF model was used to predict maximum pollutant impacts at that area. In addition, CALPUFF was used to predict the project's potential impact on visibility in the form of regional haze and the annual deposition of total sulfur and nitrogen at the ENP.

The meteorological data used in the CALPUFF analysis was a 4 kilometer grid resolution data set for the years 2001 to 2003. The data set was originally compiled for visibility studies by the Visibility Improvement State and Tribal Association of the Southeast (VISTAS), and was modified by the National Park Service to be generally applicable for Class I analysis regulatory modeling. These data were provided to the applicant by DEP.

PSD Class II Area: The EPA-approved AERMOD modeling system was used to evaluate the pollutant emissions from the proposed project in the surrounding Class II Area. The AERMOD modeling system incorporates air dispersion based on planetary boundary layer turbulence structure and scaling concepts, including the treatment of both surface and elevated sources, and both simple and complex terrain. AERMOD contains two input data processors, AERMET and AERMAP. AERMAP is the terrain processor and AERMET is the meteorological data processor.

A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options. Direction specific downwash parameters were used for all sources for which downwash was considered.

Emissions data used in the modeling analysis were obtained from the DEP ARMS database, DEP permit files, and recent PSD permit reviews. Emissions data for the new proposed facility derive from the proposed maximum permit limits imposed on the facility for each pollutant. Emissions of all NO_X sources in the modeling inventory for the purpose of modeling NO_2 against the AAQS were adjusted (reduced by 25%) in accordance with the federal regulations adopted by the department for this pollutant, per rule 62-204.800. This adjustment was made for both the annual and 1-hour NO2 averaging periods. While this adjustment was developed for the annual average, the DEP believes that this adjustment is also appropriate for the short-term 1-hour emissions in this rural area.

The AERMET meteorological data used for this analysis consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the Fort Myers Southwest Florida Regional (RSW) Airport and the Tampa International Airport (TIA) in Tampa, respectively. The 5-year period of meteorological data is from 2001 through 2005. The location of the proposed facility is 77 km to the east, northeast of the Fort Myers airport. To assess the representativeness of these data for the proposed site, a comparison was made of the land-use at the Fort Myers Airport with that at the proposed site. The three land-use parameters compared are the albedo (reflectivity of the land surface), Bowen ratio (measure of the surface moisture), and the surface roughness (a measure of the height of structures and vegetation surrounding the area). Both the albedo and the Bowen ratio are nearly the same values at both locations. The surface roughness at the airport is slightly higher than at the proposed site location, but would not be considered significantly different. Further, the general terrain in this part of Florida is flat, and large scale weather events are fairly uniform over a large area. While there would be localized differences between the two sites, especially with respect to sea or lake breezes when they occur, the fundamental set of meteorological conditions used to assess the proposed source would be similar. The Fort Myers/Tampa meteorological data set is judged representative for the proposed site's air quality analysis.

In reviewing this permit application, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification should EPA revise the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators. A more detailed discussion of the required analyses follows.

Multi-source PSD Class II Increment Analysis

The PSD increment represents the amount that new sources in an area may increase ambient ground level concentrations of a pollutant from a baseline concentration. A PSD increment analysis was required for PM_{10} and SO_2. The maximum predicted annual and maximum predicted high, second high short-term average PSD Class II area impacts from this project and other increment-consuming sources in the vicinity of the proposed facility are shown in Table 22 below.

Table 22 - PSD Class II Increment Analysis

Pollutant	Averaging Time	Max Predicted Impact ($\mu g/m^3$)	Allowable Increment ($\mu g/m^3$)	Impact Greater Than Allowable Increment?
PM_{10}	24-hour	27.0	30	No
	Annual	8.6	17	No
SO_2	3-hour	36.2	512	No
	24-hour	8.2	91	No
	Annual	0.7	20	No

Note: These results are based on the highest, second-high annual values over the five modeling years for the 3-hour and 24-hour SO_2 averaging periods, and the highest, sixth highest value over the five-year modeling period for the 24-hour PM_{10}. The annual averages are based on the maximum of the five years for both SO_2 and PM_{10}.

AAQS Analysis

For pollutants subject to an AAQS review, the total impact on ambient air quality is obtained by adding a "background" concentration to the maximum modeled concentration. This "background" concentration is based on existing monitoring data for each pollutant and representative of the area of the proposed source. This background is intended to account for sources of a particular pollutant that are not explicitly modeled. Since no attempt is typically made to subtract out the impacts due to the explicitly modeled sources on these monitored values, there is some amount of double-counting reflected in the total concentration (modeled + background) used to compare with the appropriate AAQS.

The sources that are explicitly modeled include the subject facility and nearby sources that are judged to potentially have a significant interaction with the proposed facility. The appropriate calculations for the modeled and background values are different for each pollutant, but generally follow the form for compliance with the AAQS. Table 23 shows the results of this analysis. The metrics used for the modeled impacts and the background concentrations provided in the footnotes. As shown in this table, emissions from the proposed facility are not expected to cause or contribute to a violation of an AAQS.

Based on the results of the air quality modeling analysis, the operation of the new SRF facility will not cause or contribute to a violation of an ambient air quality standard or maximum allowable concentration increase (PSD increment).

Ozone Modeling

Projects with VOC and NO_X emissions greater than 100 TPY are required to perform an ambient impact analysis for ozone including the gathering of preconstruction ambient air quality data. The applicant estimated annual potential VOC and NO_X emissions from the project to be 169 and 247 TPY respectively.

The ozone monitoring data at Belle Glade is sufficient for the purposes of background values at the SRF site.

Ozone site-specific modeling is not typically completed for single source permitting because of its complexity. Ozone is a secondarily formed pollutant that is known to be caused by the regional emissions of VOC and NO_X in combination with meteorological parameters (temperature, rainfall, solar insolation, etc.).

To conclusively prove whether or not the 169 TPY of VOC and 247 TPY of NO_X will not cause or contribute to a violation, a very sophisticated and expensive model would need to be run for the entire region. The key inputs to the model would be traffic, power plants throughout the region, other industrial sources, and meteorology. As previously discussed, the NO_X emission reductions in South Florida from FP&L projects alone have declined by nearly 80,000 TPY. The effects of the SRF on ozone would not be measurable considering the overwhelming effects of the FP&L reductions and the climatological variability. The uncertainty in any regional ozone model would be greater than the contribution from this project.

6.9. Additional Impacts Analysis

General Description with Regard to Growth and Air Quality Impacts

The population of Hendry County grew by 144 percent between 1977 and 2008 to approximately 40,000 but remains relatively small. There are no existing power plants in Hendry County. Existing power plants in Palm Beach County include Florida Power & Light Company's Riviera Plant; New Hope Power Company Boilers A, B, and C; Lake Worth Utilities; and Solid Waste Authority of Palm Beach. The major industry in eastern Hendry and western Palm Beach counties is sugar cane farming and manufacturing. Since 1977, Hendry County has been classified as attainment or maintenance for all criteria pollutants. Air quality monitoring data have been collected in Hendry County, primarily in the eastern portion of the county (Clewiston) and in western Palm Beach County (Belle Glade) as described in Section 6.3.

The site of the proposed project is located in the eastern portion of Hendry County and is surrounded by sugar cane fields. The area is distinctly rural. The nearest residence is located approximately five miles north of the site. Sweet sorghum, the primary feed stock to the ethanol plant, will be grown on 25,000 acres of land surrounding the facility.

Table 23 - Ambient Air Quality Impacts

Pollutant	Averaging Time	Major Sources Impact (μg/m^3)	Background Conc. (μg/m^3)	Total Impact (μg/m^3)	Total Impact Greater Than AAQS?	AAQS (μg/m^3)
PM_{10}	24-hour	26.3 [a]	49.0 [b]	75.2	No	150
	Annual	8.6 [c]	20 [d]	28.6	No	50
$PM_{2.5}$	24-hour	14.3 [e]	14 [f]	28.3	No	35
	Annual	2.0 [e]	6.5 [g]	8.5	No	15
SO_2	1-hour	75.7 [j]	13.1 [k]	88.8	No	196
	3-hour	52.8 [l]	7.8 [b]	60.6	No	1300
	24-hour	15.1 [l]	5.5 [b]	20.6	No	260
NO_2	1-hour	76.2 [h]	86.5 [i]	162.7	No	189

a. High 6th high value over the five-year period.
b. Design value - highest second-high value over recent three years from representative monitor.
c. Highest annual average predicted concentration over five years
d. Design value - highest annual average over recent three years from representative monitor.
e. Five-year average of the annual modeled maximum 24-hour value and maximum annual modeled value – per March 23, 2010, EPA memo from Stephen Page, Modeling Procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS.
f. Design value - three year average of the 98th percentile of 24-hour concentrations.
g. Design value - three year average of the arithmetic annual means.
h. 98th percentile of the annual distribution of daily maximum 1-hour values averaged over the five modeled years – per June 29, 2010, EPA memo from Stephen Page, Guidance Concerning the Implementation of the 1-hour NO_2 NAAQS for the Prevention of Significant Deterioration Program.
i. Maximum measured 1-hour value over recent three years at representative monitor – per June 29, 2010, memo cited above.
j. 99th percentile of the annual distribution of daily maximum 1-hour values averaged over the five modeled years – per August 23, 2010, EPA memo from Stephen Page, Guidance Concerning the Implementation of the 1-hour SO_2 NAAQS for the Prevention of Significant Deterioration Program.
k. Maximum measured 1-hour value over recent three years at representative monitor – per August 23, 2010 memo cited above.

Growth-Related Impacts Due to the Proposed Project

According to the applicant, the proposed project will provide up to 10 new permanent employees and up to 60 short-term employees during the 12 to 18 month construction of the facility. The applicant states that the workforce needed to construct and operate the facility represents a small fraction of the population already present in the immediate area, and therefore the effect on air quality levels would be minimal.

Impact on Soils, Vegetation, and Wildlife

The pollutants that will be emitted from the proposed facility (SO_2, NO_X, and PM), along with pollutants formed from these pollutants (ozone) may cause injury to soils, vegetation, and wildlife if present at high enough concentrations. The applicant performed air quality modeling to estimate the concentrations of these pollutants to compare with levels that show injury taken from the literature. In addition, the secondary national ambient air quality standards defined for these pollutants are set to protect public welfare, and thus, also provide information on the potential for injury at predicted concentration levels. These secondary standards are identical to the primary health standards, with the exception that the federal three-hour SO_2 standard is just a secondary standard. The modeling results for the proposed SRF project show projected impact levels below those that the literature and the standards indicate might cause potential injury.

Class I Area Impacts- Air Quality Related Values (AQRV)

Everglades National Park is the nearest Class I area to the proposed project and is located 85 km to the south. Modeling analysis showed that emissions from the proposed facility have an insignificant ambient air impact. The primary AQRV in the Everglades include visibility and deposition of sulfates and nitrates. The applicant performed a visibility (regional haze) analysis for the impact of the proposed facility on the Everglades. Table 24 shows the results of this analysis. Visibility impacts are less than criterion of 5%, considering two different calculation methods.

Table 24 - Maximum 24-hour Visibility Impairment Predicted from the Proposed Facility at the Everglades National Park Class I Area

Background Extinction Calculation	Visibility Impairment (%) [a]			Visibility Impairment Criterion (%)
	2001	2002	2003	
Method 2 with RHMAX=95%	1.94	1.73	2.42	5.0
Method 6 with Monthly F(RH)	1.12	0.96	1.13	5.0
a. Concentrations are highest predicted using CALPUFF V5.8, 4-km domain for 2001-2003. Background extinction calculated using FLAG document (December 2000) and stated method.				

Total nitrogen (N) and sulfur (S) deposition rates were predicted using the CALPUFF model. Deposition thresholds were developed by the Federal Land Managers that represent the additional amount of N or S deposition within a Class I area below which impacts from a new or modified source are considered insignificant. Table 25 provides the results of this analysis. Deposition of both N and S are well below the threshold of 0.01 kilograms per hectare per year (kg/ha/yr).

Table 25 - Maximum Annual Nitrogen and Sulfur Deposition from the Proposed Facility at the Everglades National Park Class I Area

Species	Year	Total Deposition (Wet and Dry)		Deposition Analysis Threshold
		g/m²/s	kg/ha/yr	kg/ha/yr
Nitrogen (N) Deposition	2001	2.16×10^{-12}	0.0007	0.01
	2002	3.24×10^{-12}	0.0010	0.01
	2003	2.62×10^{-12}	0.0008	0.01
Sulfur (S) Deposition	2001	4.57×10^{-12}	0.0014	0.01
	2002	5.68×10^{-12}	0.0018	0.01
	2003	4.34×10^{-12}	0.0014	0.01

7. CONCLUSION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution control regulations as conditioned by the Draft Permit.

SECTION IV. APPENDICES

CONTENTS

SECTION IV. APPENDIX ASME

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.

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

PTC 4.1-b (1964)

Revised September, 1965

CALCULATION SHEET

ASME TEST FORM FOR ABBREVIATED EFFICIENCY TEST

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

30	HEAT OUTPUT IN BOILER BLOW-DOWN WATER = LB OF WATER BLOW-DOWN PER HR × $\left[\dfrac{\text{ITEM 15} - \text{ITEM 17}}{1000}\right]$ = ... kB/hr
24	*If impractical to weigh refuse, this item can be estimated as follows* DRY REFUSE PER LB OF AS FIRED FUEL = $\dfrac{\text{\% ASH IN AS FIRED COAL}}{100 - \text{\% COMB. IN REFUSE SAMPLE}}$ CARBON BURNED PER LB AS FIRED FUEL = $\dfrac{\text{ITEM 43}}{100} - \left[\dfrac{\text{ITEM 22} \times \text{ITEM 23}}{14{,}500}\right]$ = ... 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 = $\dfrac{11CO_2 + 8O_2 + 7(N_2 + CO)}{3(CO_2 + CO)}$ × (LB CARBON BURNED PER LB AS FIRED FUEL + $\frac{3}{8}$ S) = $\dfrac{11 \times \text{ITEM 32} + 8 \times \text{ITEM 33} + 7(\text{ITEM 35} + \text{ITEM 34})}{3 \times (\text{ITEM 32} + \text{ITEM 34})} \times \left[\text{ITEM 24} + \dfrac{\text{ITEM 47}}{267}\right]$ = ...
36	EXCESS AIR † = $100 \times \dfrac{O_2 - \frac{CO}{2}}{.2682N_2 - (O_2 - \frac{CO}{2})}$ = $100 \times \dfrac{\text{ITEM 33} - \frac{\text{ITEM 34}}{2}}{.2682\ (\text{ITEM 35}) - (\text{ITEM 33} - \frac{\text{ITEM 34}}{2})}$ = ...

	HEAT LOSS EFFICIENCY	Btu/lb AS FIRED FUEL	LOSS/HHV × 100 =	LOSS %
65	HEAT LOSS DUE TO DRY GAS = LB DRY GAS PER LB AS FIRED FUEL × C_p × ($t_{lvg} - t_{air}$) = Unit ITEM 25 × 0.24 (ITEM 13) − (ITEM 11) =	......	$\frac{65}{41}$ × 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)} = ...	......	$\frac{66}{41}$ × 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)] = ...	......	$\frac{67}{41}$ × 100 =	......
68	HEAT LOSS DUE TO COMBUSTIBLE IN REFUSE = ITEM 22 × ITEM 23 = ...	......	$\frac{68}{41}$ × 100 =	......
69	HEAT LOSS DUE TO RADIATION* = $\dfrac{\text{TOTAL BTU RADIATION LOSS PER HR}}{\text{LB AS FIRED FUEL} - \text{ITEM 28}}$	......	$\frac{69}{41}$ × 100 =	......
70	UNMEASURED LOSSES **	......	$\frac{70}{41}$ × 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.

BEST MANAGEMENT PRACTICES (BMP) PLAN

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.

Best Management Practice – Quality Assurance of Biomass	9) Prohibited Materials: 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.

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.]

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

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.

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.]

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,

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 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.

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.

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

CITATION FORMATS AND GLOSSARY OF COMMON TERMS

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

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.*

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

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.]

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.

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.

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**

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

(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:

$$E_n = \frac{(EL_{go}H_{go}) + (EL_{ro}H_{ro}) + (EL_cH_c)}{(H_{go} + H_{ro} + H_c)}$$

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 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.

(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,

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 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 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.

(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

(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;

(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;

(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;

(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

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

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.

(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).

(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.

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 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.

(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.

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**

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

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_2 or 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_2 concentration 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_2 during unit operation, percent CO_2 wet basis.

5.2.2 When measurements of CO_2 concentration are on a dry basis, use the following equation:

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

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_2 during unit operation, percent CO_2 dry basis.

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

5.2.3 When measurements of O_2 concentration are on a wet basis, use the following equation:

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

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.

$\%O_{2w}$= Hourly concentration of O_2 during unit operation, percent O_2 wet 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_2 concentration 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_2 during unit operation, percent O_2 dry 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:

$$HI_c = \sum_{q=1}^{\text{no. current quarter}} HI_q \qquad (Eq.\ F\text{-}18b)$$

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_2 emissions 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:

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

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:

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

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.

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:

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

M_c = 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:

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

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.

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:

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

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:

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

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:

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

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:		

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

GENERAL CONDITIONS

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

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

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

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

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

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

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

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

   a. Have access to and copy and records that must be kept under the conditions of the permit;

   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,

   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

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

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

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

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

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

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.
10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.
11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.
12. This permit or a copy thereof shall be kept at the work site of the permitted activity.
13. This permit also constitutes:
    a. Determination of Best Available Control Technology (X);
    b. Determination of Prevention of Significant Deterioration (X);
    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.

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.

§ 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.

SECTION IV. APPENDIX IIII

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

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

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.

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

PRELIMINARY LEAK DETECTION AND REPAIR (LDAR) PROGRAM

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.

- 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.

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 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

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.

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.

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:

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.

(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.

(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:

(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.

(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

(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.

(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.

§ 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.

§ 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.

(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

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:

(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.

(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.

(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:

(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.

(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:

$V_{max}= K_1+ K_2H_T$

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.

(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.

(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.

(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

(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]

(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

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

From: Walker, Elizabeth (AIR)
Sent: Friday, November 19, 2010 5:55 PM
To: 'dmarkley@serenewablefuels.com'
Cc: Satyal, Ajaya; 'abrams.heather@epamail.epa.gov'; 'dee_morse@nps.gov'; Mr. David A. Buff, P.E., Golder Associates, Inc.; 'mgardner@fbclew.com'; 'mali.chamness@clewiston-fl.gov'; 'bocc1@hendryfla.net'; 'mitchellcypress@semtribe.com'; 'richardbowers@semtribe.com'; 'ctepper@semtribe.com'; Gibson, Victoria; Linero, Alvaro; Read, David; 'amotlow@semtribe.com'
Subject: ASPRING ADVANCED BIOREFINERY; 0510032-001-AC/PSD-FL-412
Attachments: signature_pages.pdf

Dear Sir/ Madam:

Attached is the official **Revised Notice of Intent to Issue** for the project referenced below. Click on the link displayed below to access the permit project documents and send a "reply" message verifying receipt of the document(s) provided in the link; this may be done by selecting "Reply" on the menu bar of your e-mail software, noting that you can view the documents, and then selecting "Send".

Note: We must receive verification that you are able to access the documents. Your immediate reply will preclude subsequent e-mail transmissions to verify accessibility of the document(s).

Click on the following link to access the permit project documents:

http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0510032.001.AC.R_pdf.zip

Owner/Company Name: SOUTHEAST RENEWABLE FUELS, LLC
Facility Name: ASPRING ADVANCED BIOREFINERY
Project Number: 0510032-001-AC/PSD-FL-412
Permit Status: REVISED DRAFT
Permit Activity: CONSTRUCTION
Facility County: HENDRY

This is a Draft Revision of a previously issued draft revised by stipulation between the Department and Southeast Renewable Fuels, LLC.

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Access these documents by clicking on the link provided above, or search for other project documents using the "*Air Permit Documents Search*" website at http://www.dep.state.fl.us/air/emission/apds/default.asp.

Permit project documents are addressed in this email may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible, and verify that they are accessible. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record. If you have any problems opening the documents or would like further information, please contact the Florida Department of Environmental Protection, Bureau of Air Regulation.

Elizabeth Walker
Bureau of Air Regulation
(850) 921-9505

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