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, 2010

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.

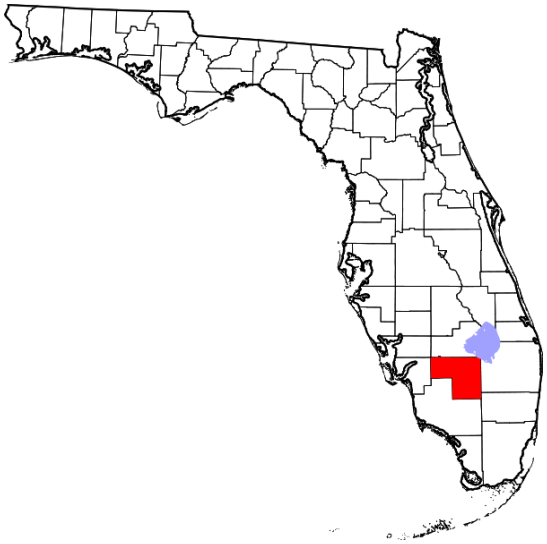


Figure 1 - Hendry County, Florida

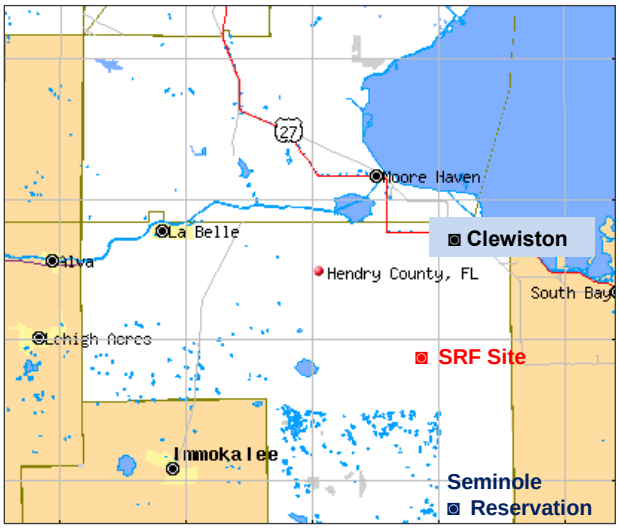


Figure 2 - Proposed Location of SRF, Hendry County

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.

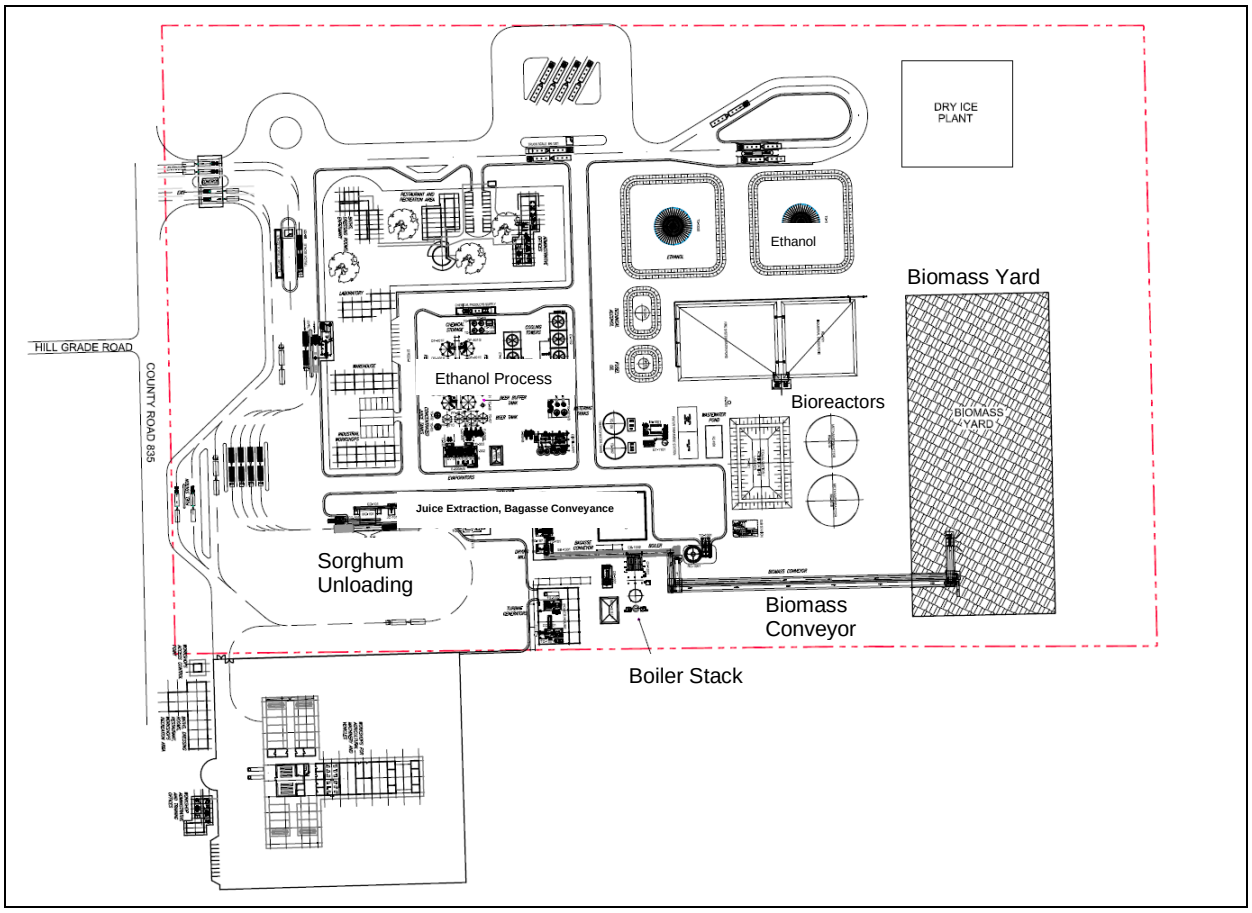


Figure 5 – Preliminary Layout of Future SRF Facility

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. (E.U. 001) Material Handling and Preparation

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.

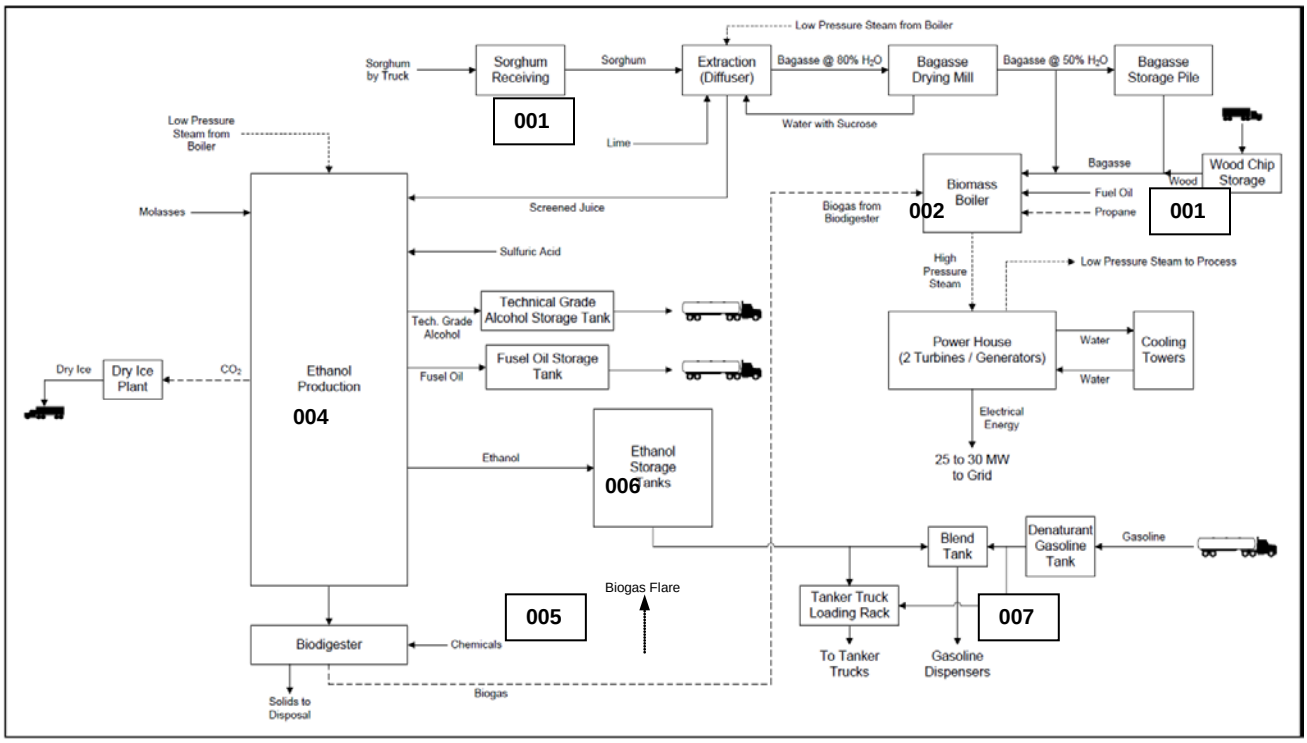


Figure 7 – Simplified Diagram of SRF Sorghum to Ethanol and Power Facility

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 (≤ 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).

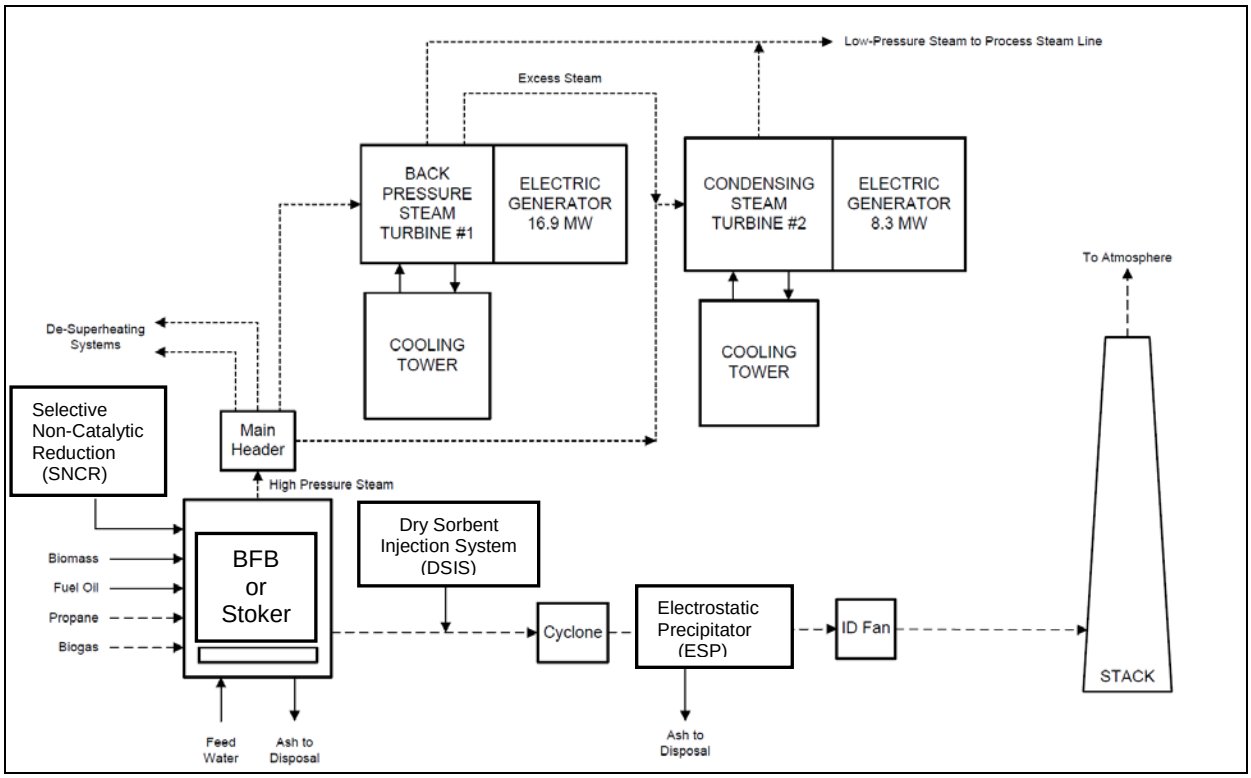


Figure 8 – Simplified Diagram of Applicant's Proposed SRF Steam and Electricity Production Cycles

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.

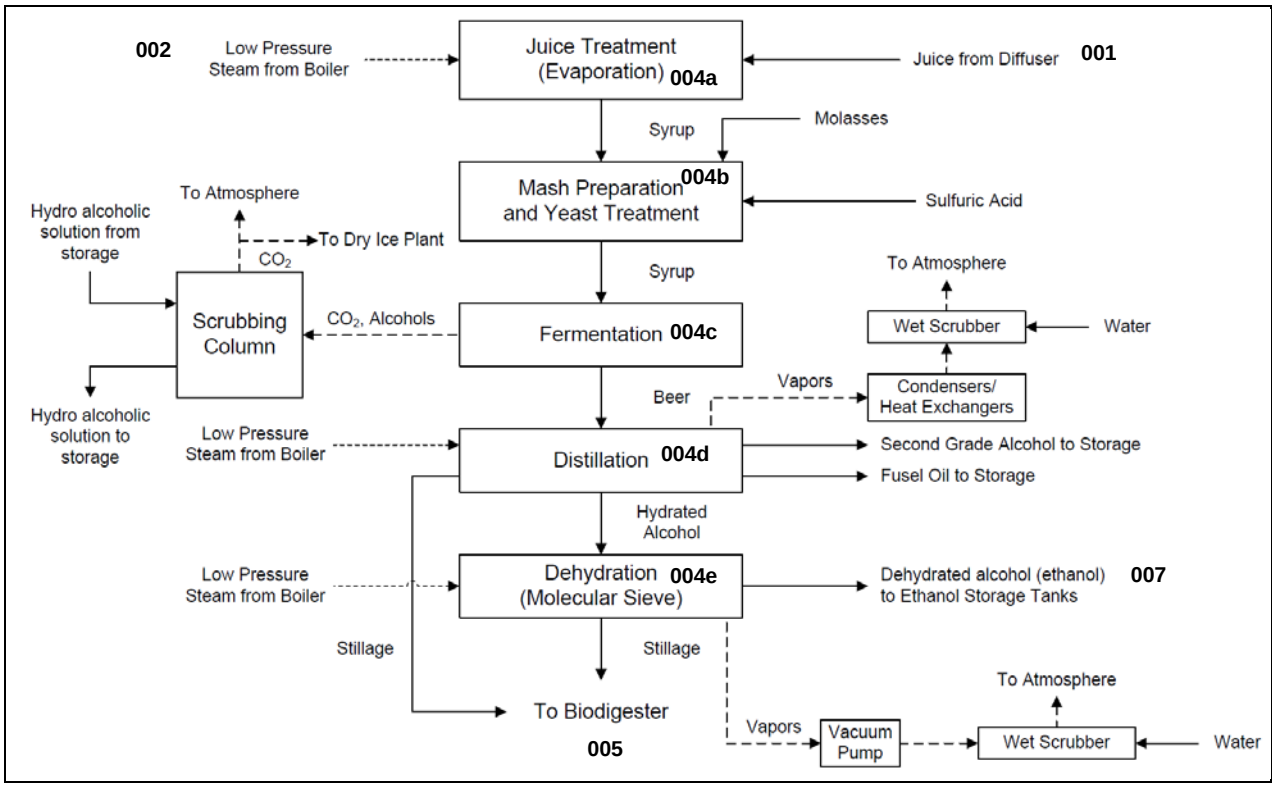


Figure 9 – Simplified Diagram of SRF Sweet Sorghum to Ethanol Production Process

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	223.2	53.1/36.4	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, and 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., and 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.

[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, Subpart 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, Subpart 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 JJJJJJ – 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, the 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.

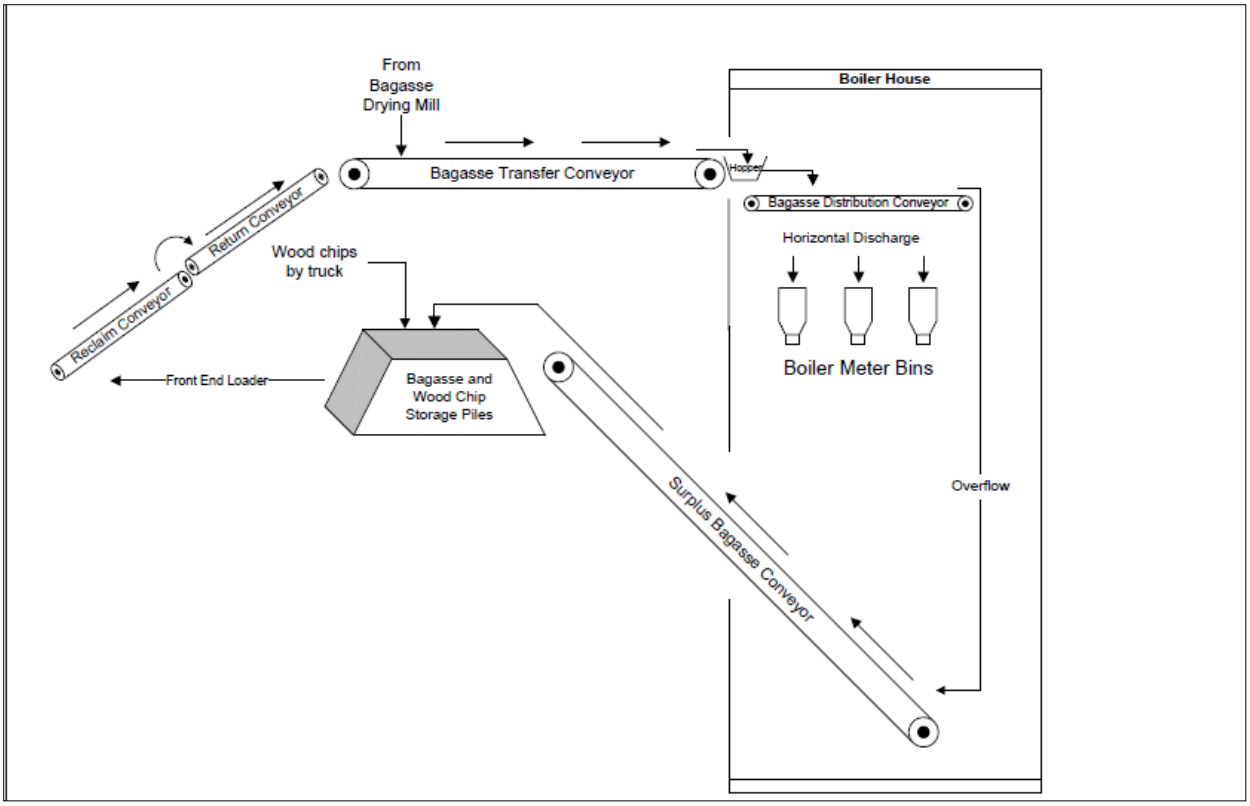


Figure 10 - Boiler Biomass Feed System.

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

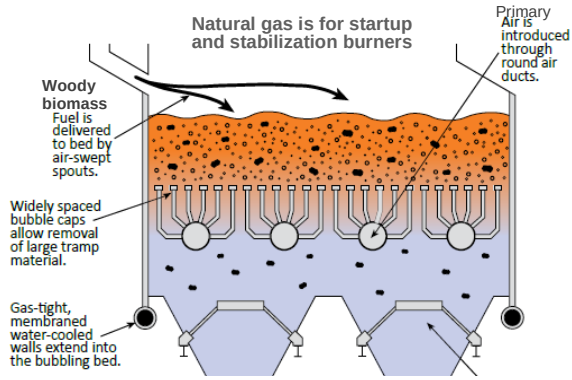
<u>NO_X Formation and Primary Control</u>.

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.

<u>BFB Boiler Principles.</u> 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 <u>but not high enough to form thermal NO_X</u>.

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.



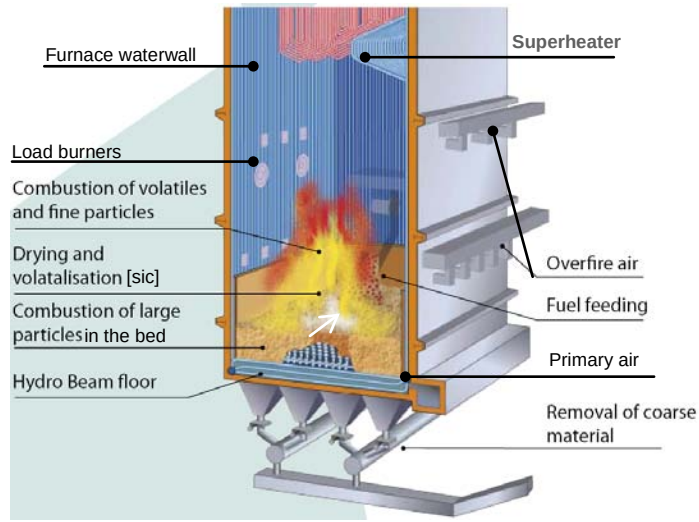


Figure 11 – Bed Description for B&W BFB Boiler **Figure 12 – Typical METSO HYBEX BFB Boiler**

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:

$$CHi^* + NO \rightarrow HCN + ... \qquad \text{Eq. 1}$$

Where:

i = 1, 2, 3

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

$$HCN + NO \rightarrow N_2 + CO + CO_2 + H_2O + ... \qquad \text{Eq. 2}$$

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

$$NHi^* + NO \rightarrow N_2 + ... \qquad \text{Eq. 3}$$

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:

$$CharC + NO \rightarrow N_2 + CO + CO_2 + ... \qquad \text{Eq. 4}$$

$$CharN + O_2 \rightarrow N_2 + O_2 + ... \qquad \text{Eq. 5}$$

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.

$$NH_3 + O_2 \rightarrow NO + ...$$ Eq. 6

$$HCN + O_2 \rightarrow NO + ...$$ Eq. 7

$$CharC + O_2 \rightarrow NO + ...$$ Eq. 8

$$CharN + O_2 \rightarrow NO + ...$$ 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.

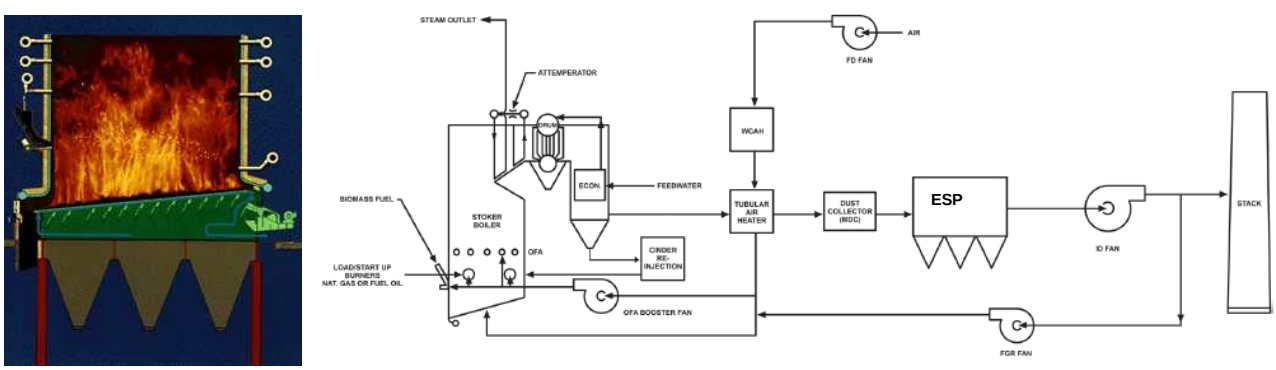


Figure 13 – Detroit Hydro-Grate and Typical Stoker-based Process Schematic

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, "<u>the spreader stoker technology results in inherently higher uncontrolled NO_X emissions compared to the fluidized bed boiler</u>".[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.

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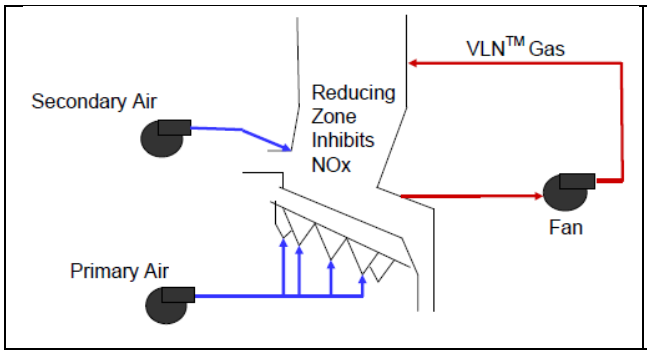
5 Brochure - Bubbling Fluidized Bed or Stoker — Which is the Right Choice for Your Renewable Energy Project?

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.



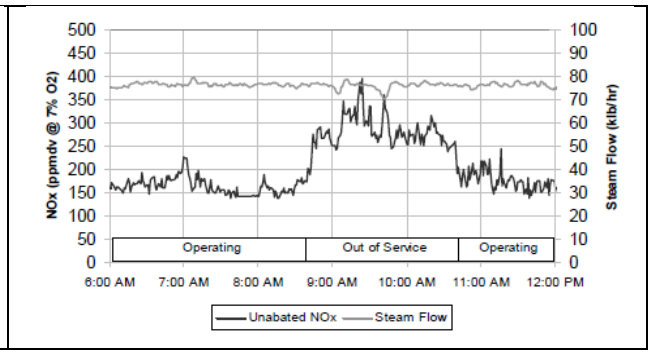


Figure 14 – Diagram of the VLN™ Process **Figure 15 – Operation with/without/with VLN™ System**

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 before the air preheaters and no reheat of exhaust gases is required.

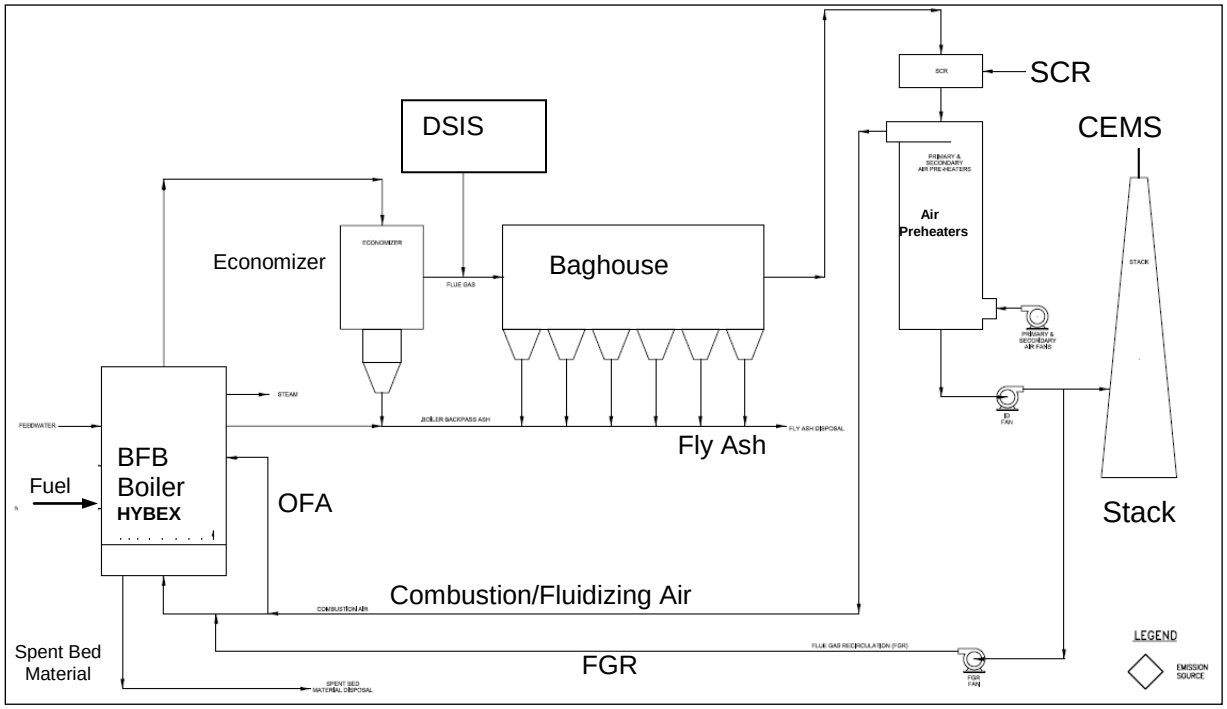


Figure 16 – Gainesville Renewable Energy Center (GREC) BFB Pollution Control Technologies

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 after 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.

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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.

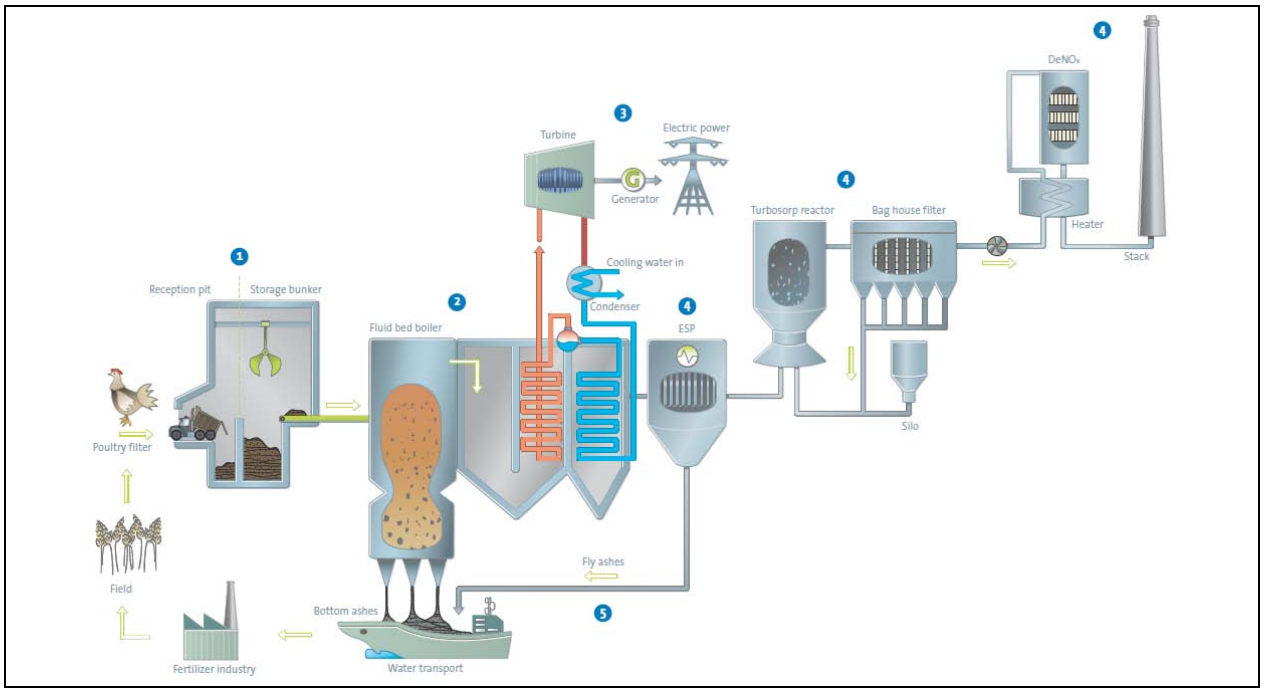

Figure 17 – Basic Process and Air Pollution Control Equipment Diagram for Moerdijk BFB Boiler

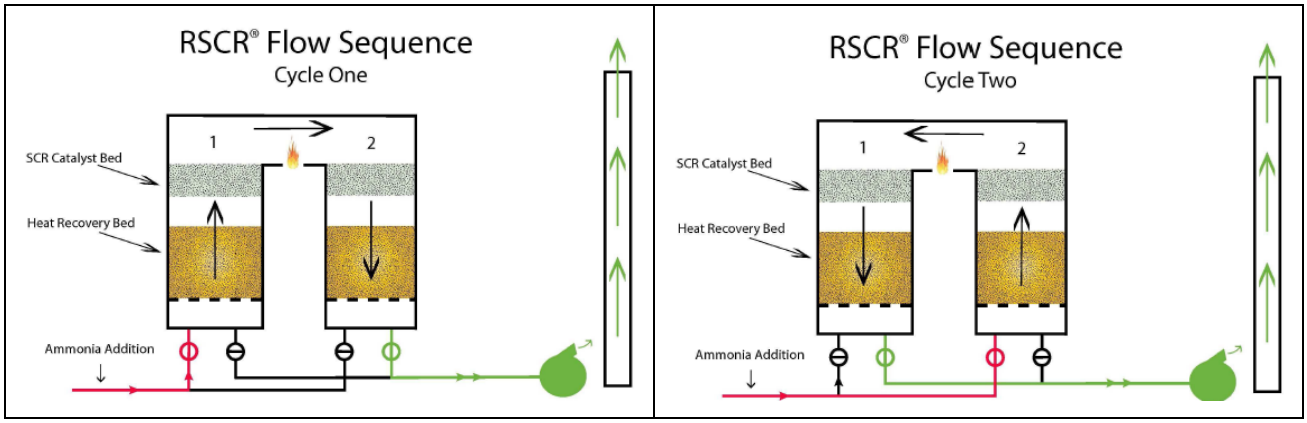

Figure 18. Principle of RSCR incorporating Duct Burner and Thermal Media (Ox-cat not shown).

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_en.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

[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.

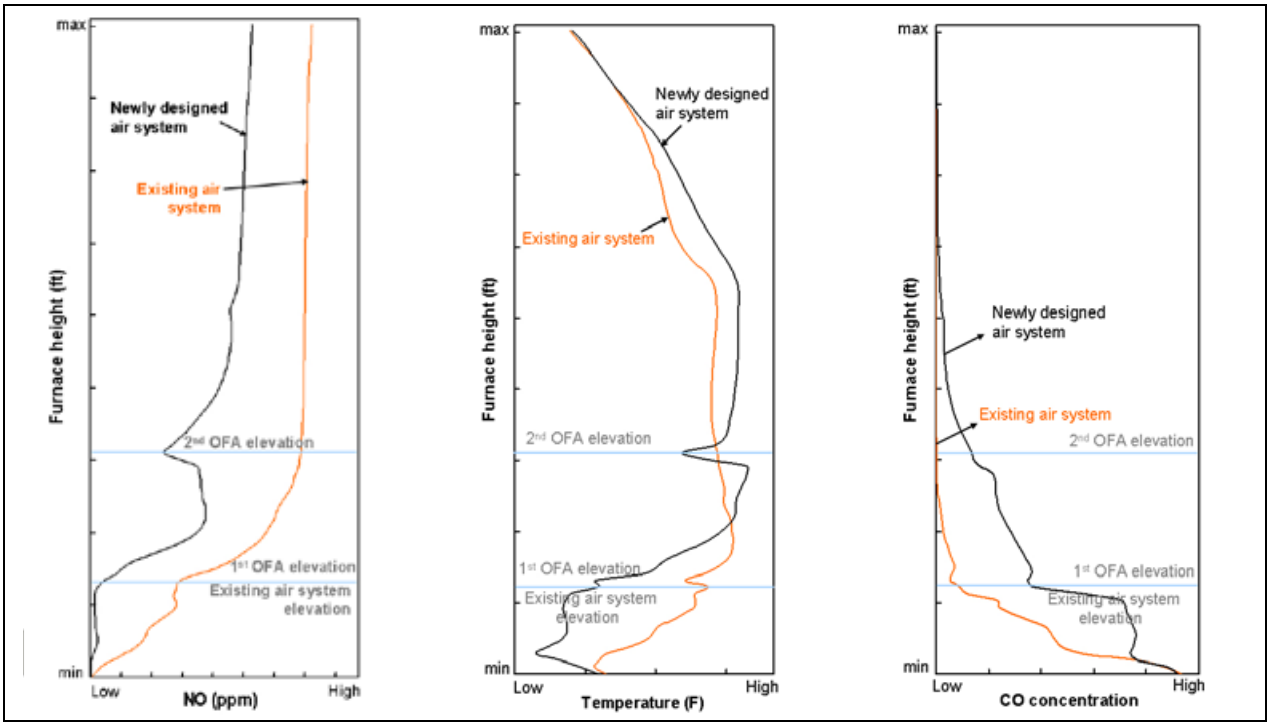


Figure 19. Modeled NO_X, Temperature and CO a BFB Boiler after Switching to Low NO_X strategy.

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"*.

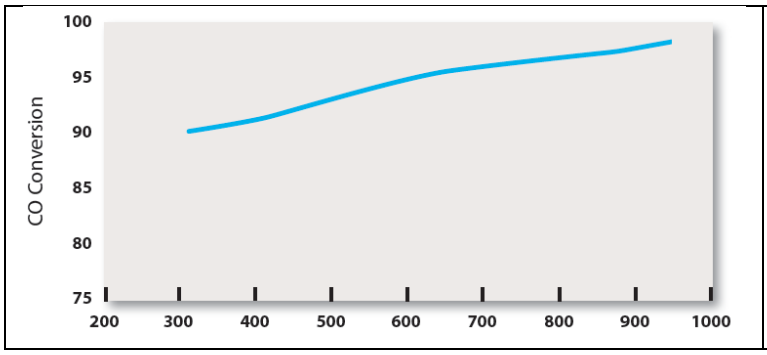
The project-specific RSCR bid and adjustments by SRF (and the Department) are discussed in Section 4.2 above. According to the applicant, the cost of RSCR is extremely high for CO reduction only, and only achieves a small incremental reduction in NO_X emissions.

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.



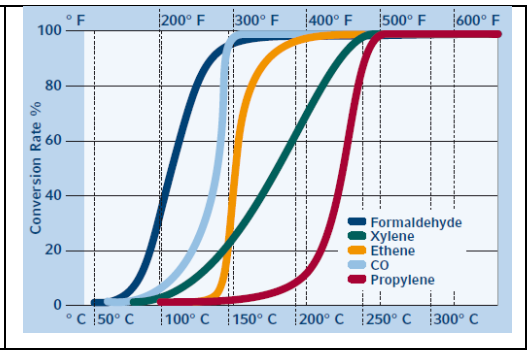


Figure 20. Ox-cat Performance vs. Temperature (^oF) **Ox-cat Performance vs. Temperature (^oC)**

[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, Subpart 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 ^{o}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 ^{o}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.

[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, organic 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, this 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.

[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, the 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, service 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

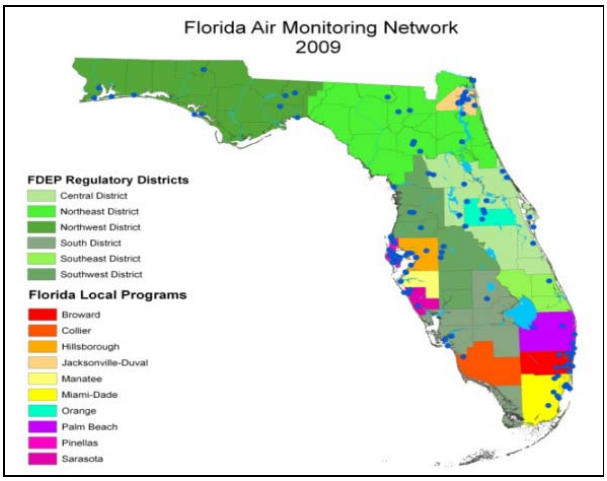
Table 15 - Largest Sources of PM_{10} (2009) in Counties near to the Proposed Plant (TPY)

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.



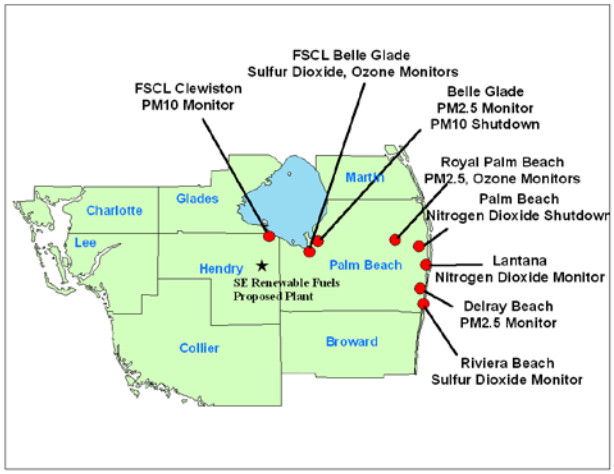


Figure 21 – Air Monitoring Network **Figure 22. Monitors in Hendry and Palm Beach Counties**

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 µg/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 µg/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 µg/m^3) was reported as the annual compliance value and compared with the standard of 15 µg/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.

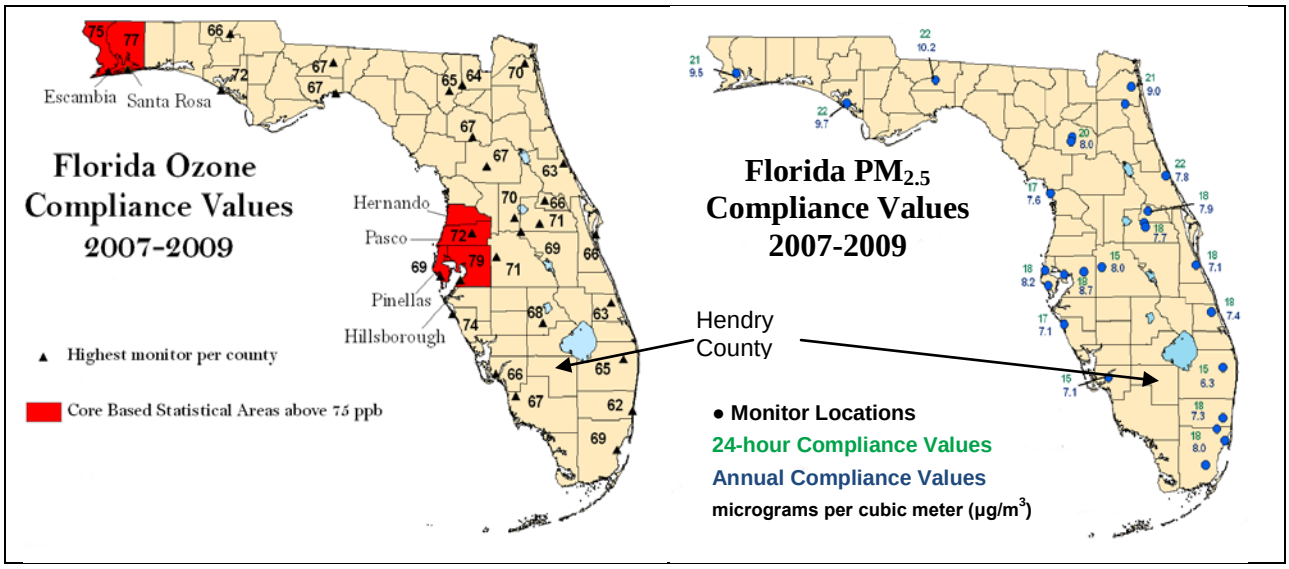


Figure 23 – Florida Ozone Compliance Values **Figure 24 – Florida $PM_{2.5}$ Compliance Values**

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. $PM_{2.5}$ Precursor Emissions from Power Plants in the Southeastern U.S.

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.

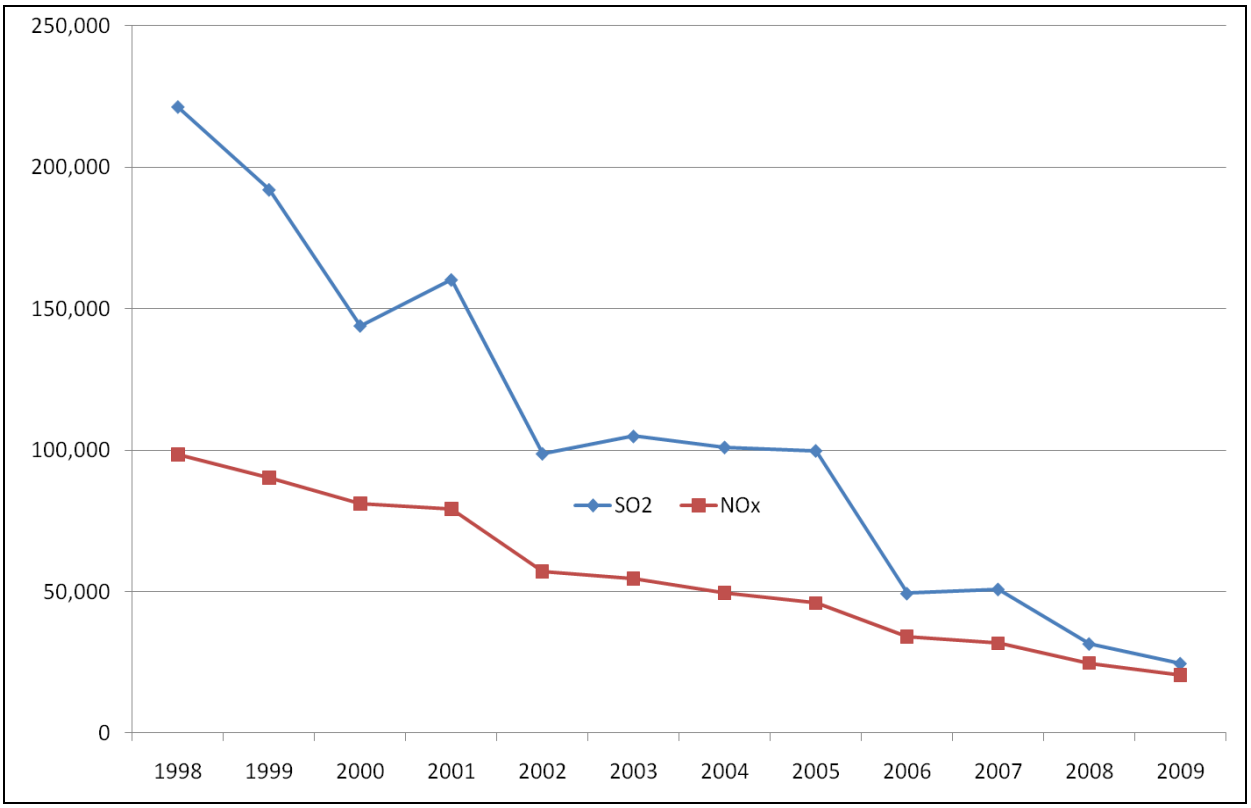


Figure 25 – SO_2 and NO_X reductions in TPY at FPL Peninsular Facilities (1998-2009)

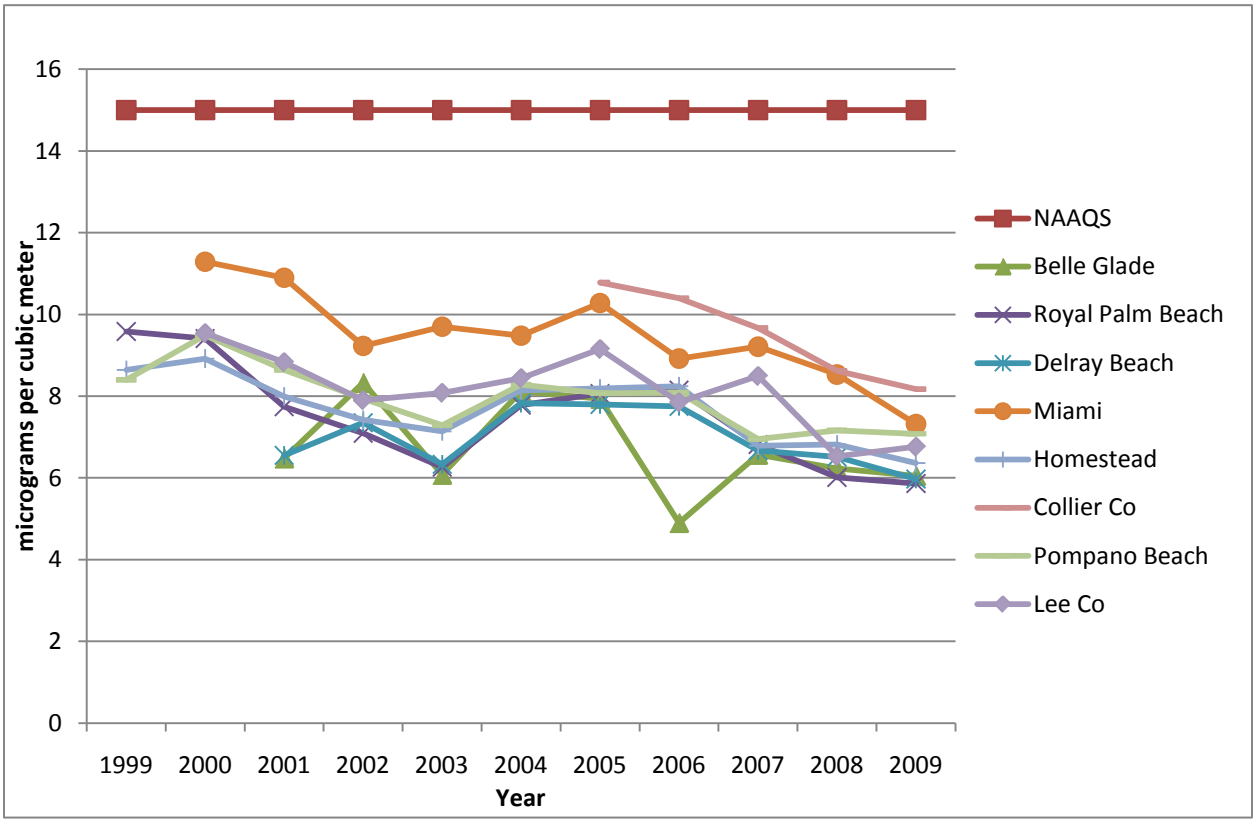


Figure 26. South Florida Annual Average $PM_{2.5}$ Trends (1999 – 2009)

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 (μg/m^3)	De Minimis Level (μg/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 ($\mu g/m^3$)	Background Conc. ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Total Impact Greater Than AAQS?	AAQS ($\mu g/m^3$)
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
		$g/m^2/s$	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.