TECHNICAL EVALUATION

&

PRELIMINARY DETERMINATION

APPLICANT

Highlands EnviroFuels, LLC
10027 Water Works Lane
Riverview, FL 33578

PROJECT

Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant
ARMS Facility ID No. 0550063

DEP File No. 0550063-001-AC (PSD-FL-416)

COUNTY

Highlands County, Florida

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resource Management
Office of Permitting and Compliance
2600 Blair Stone Road, MS# 5505
Tallahassee, Florida 32399-2400

August 11, 2011

1. APPLICATION INFORMATION

1.1. Applicant Name and Address

Highlands EnviroFuels, LLC (HEF)
10027 Water Works Lane
Riverview, FL 33578

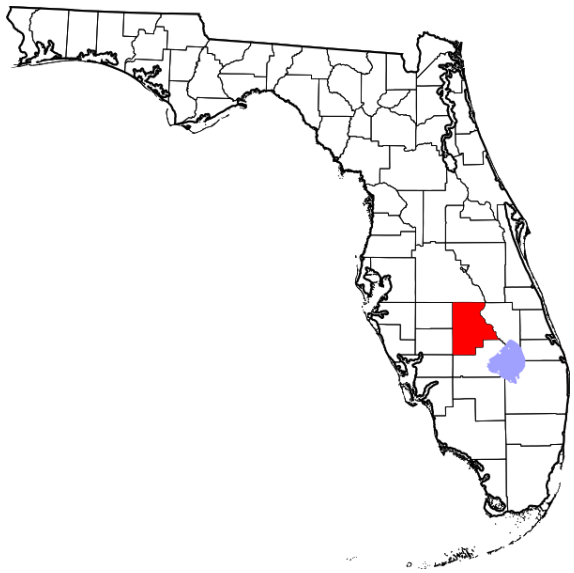
Authorized Representative: Dr. Bradley Krohn, President

1.2. Key Dates

- June 2, 2011 — Received a Prevention of Significant Deterioration (PSD) air construction permit application from HEF.
- June 14 — Department met with HEF and Golder Associated to discuss application.
- June 28 — Department received additional information from HEF.
- July 1 — EPA announced issuance of a final rule that defers, for a period of three years, greenhouse gas (GHG) permitting requirements for carbon dioxide (CO_2) emissions from biomass-fired and other biogenic sources.
- August 11 — Department issued Draft Permit decision for HEF and posted documents.

1.3. Facility Location

The HEF facility will be located approximately 0.5 miles southwest of the intersection of U.S. Highway 27 and State Road (SR) SR 70, south of Lake Placid in Highlands County. The UTM coordinates are Zone 17; 466.407 kilometers (km) East and 3,009.015 km North. The locations of Highlands County and the proposed site are shown in Figures 1 and 2.



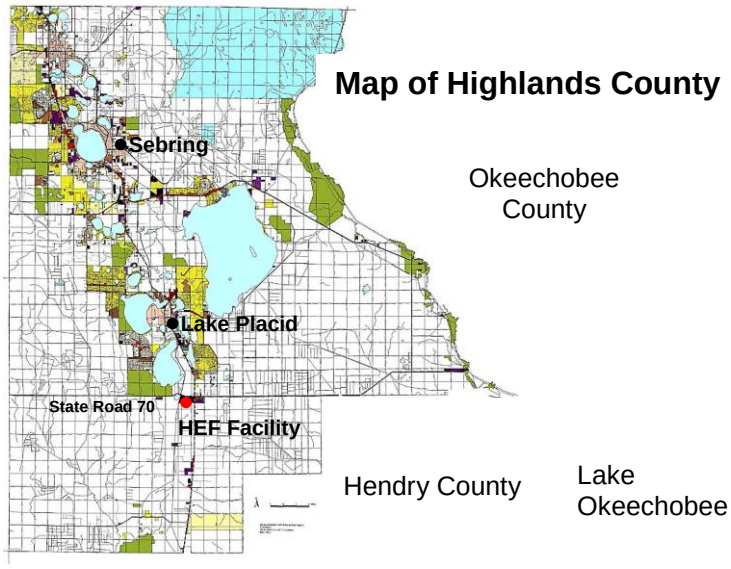


Figure 1 - Highlands County, Florida **Figure 2 - Proposed Location of HEF Facility**

Highlands County is bounded by the Kissimmee River and Okeechobee County to the east and Hendry County to the south. Lake Okeechobee is located approximately 36 km to the southeast. The proposed HEF facility will be located on 75 acres of citrus farmland immediately south of an east-west spur of the CSX Railroad as shown in Figure 3.

Sugarcane and sweet sorghum (cane) for the proposed HEF facility will be grown on nearby farms comprising about 30,000 to 36,000 acres. Figures 4 is a photograph taken on SR 70 near the entrance of an adjacent (inactive) industrial park located north of the HEF site. Figure 5 was taken from U.S. Highway 27 that runs in a north-south direction approximately 0.5 miles east of the site.

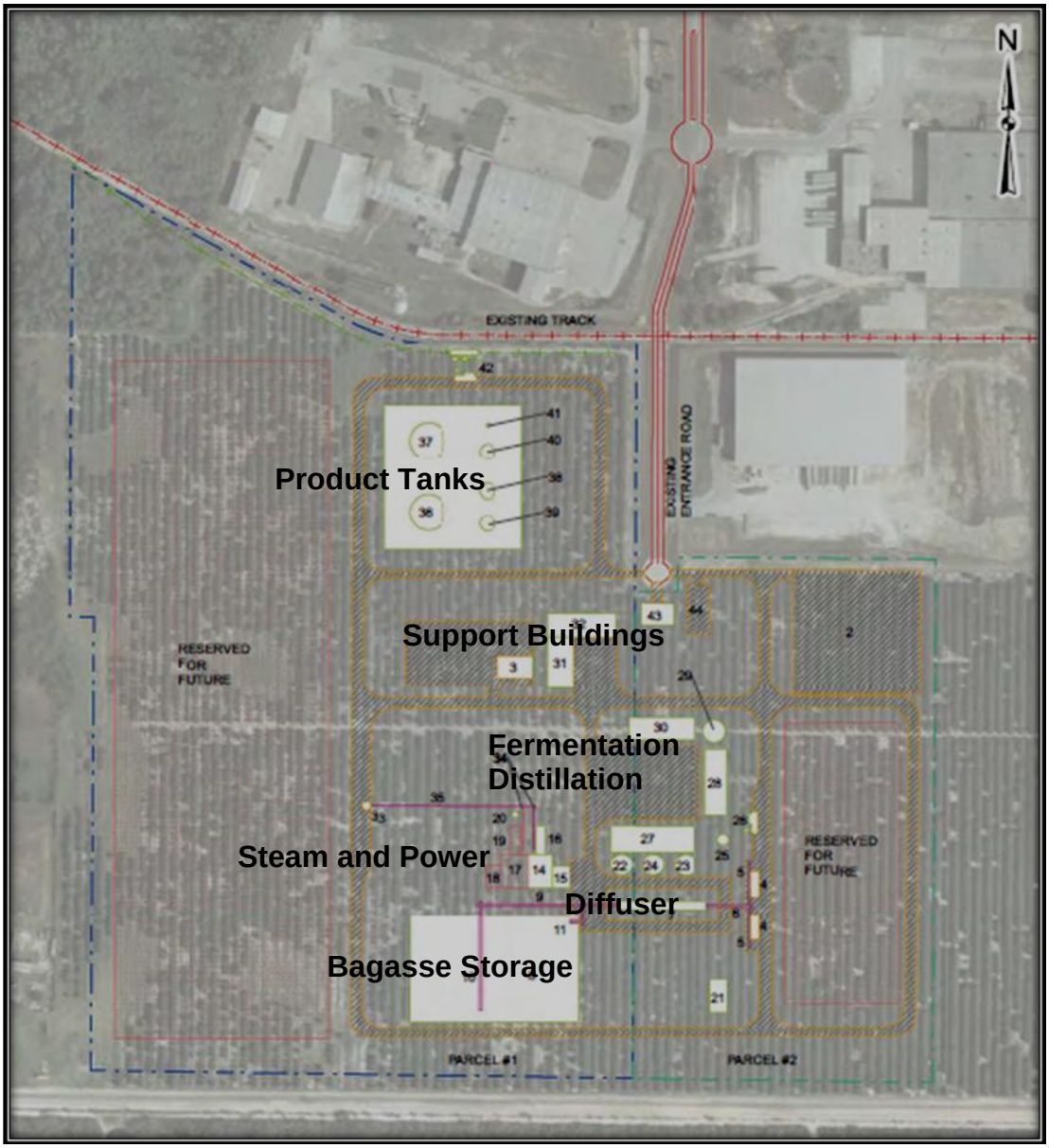


Figure 3 – Preliminary Layout of Future HEF Facility

Figure 4 – Road from SR 70 towards HEF Site

Figure 5 – View from U.S. 27 towards HEF Site

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 approximately 147 km south of the proposed HEF site.

1.4. Project Description

The applicant proposes to construct a sugarcane and sweet sorghum-to-ethanol advanced biorefinery with a maximum annual ethanol (C_2H_5OH) production rate of 36 million gallons per year (MGPY). The cane (i.e. the sugarcane and sorghum) will be grown on nearby farmland. The juice will be squeezed from the feedstock stalks, fermented, distilled and blended to make a range of ethanol/gasoline products, including E-85 (an 85/15 ethanol/gasoline blend). The leftover stalk fiber (bagasse) will be combusted in a cogeneration biomass boiler to make process steam and up to 30 megawatts (MW, gross) of electricity. In addition to bagasse, HEF will use supplemental biomass consisting of energy crops, wood chips and vegetative debris. Natural gas will be used for startup shutdown and flame stabilization and during a disruption in the biomass supply.

The HEF process is akin to conventional sugar production practiced in South Florida, except that the juice is fermented and distilled to produce ethanol rather than evaporated and refined to produce sugar.

The main process steps are:

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

Table 1 indicates the emissions units (EU) associated with this project. Figure 6, provided by HEF, is a simplified process flow diagram for the project with only the key EU indicated.

Table 1 - Process Steps Comprising the HEF by EU.

EU ID No.	Emissions Unit Description
001	Feedstock and Biomass Material Handling and Preparation
002	Biomass Boiler
003	Cooling Towers
004	Ethanol Production Process
005	Product Loadout and Flare
006	Storage Tanks
007	Miscellaneous Storage Silos
008	Emergency Equipment
009	Facility-Wide Fugitive Volatile Organic Compounds (VOC) Equipment Leaks

2. PROCESS DESCRIPTION

2.1. (E.U. 001) Feedstock and Biomass Material Handling and Preparation

Cane receiving. Refer to Figure 6. Harvested cane stalks in the form of 6 to 12 inch billets will arrive via trucks or rail from nearby agricultural fields to the production facility. The trucks and railcars will be weighed on a weighing bridge as they enter the unloading area. The cane in the trucks is then transferred to the feed table via a tipping trailer. Railcars will be bottom dumped into a feed hopper, which feeds the feed table. The feed table is equipped with chains that convey the cane billets toward the main conveyor that feeds the juice extraction system.

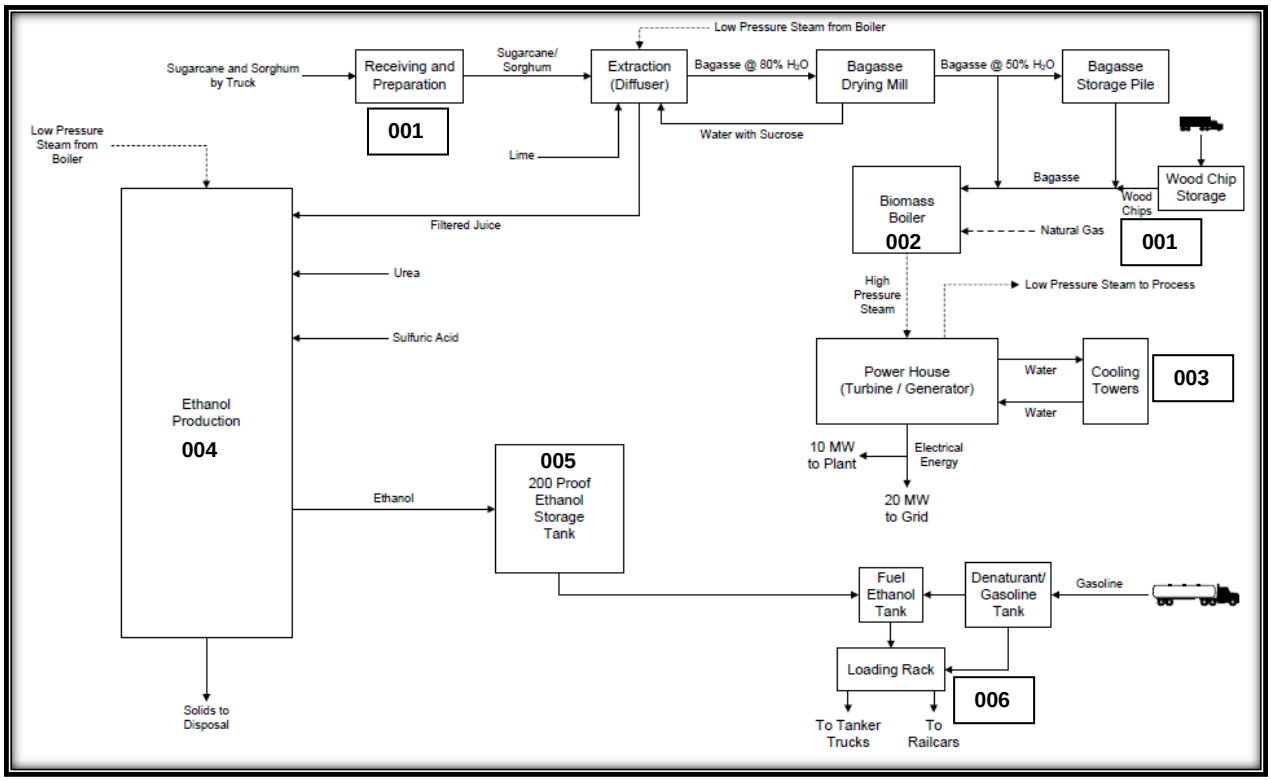


Figure 6 – Simplified Diagram of HEF Sugarcane and Sorghum to Ethanol and Power Facility

Supplemental boiler fuel receiving. Energy crops, wood chips and vegetative debris will be received from local suppliers.

Sorghum cutting, shredding and conveyance. The cane passes through several sets of revolving cane knives and one heavy-duty shredder. From the shredder, the cane passes to a high-speed belt carrier then to the diffuser feed carrier. Any excess cane 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. Imbibition water is fed into the juice trough and falls onto the shredded cane 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 is circulated in a countercurrent manner such that it is progressively concentrated in sucrose in the direction of the incoming shredded cane.

The washed and shredded cane (now bagasse) is pressed in a roller system to approximately 50 percent (%) moisture and is then transferred to the biomass boiler. The juice is pumped to a juice screen which separates fine particles prior to evaporation. The fine particles are recycled to the diffuser. The pH of the filtered juice is adjusted and the product is stored in the juice storage tank.

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

The project will employ one biomass grate stoker boiler with a maximum capacity of 504.3 million Btu per hour (mmBtu/hr on a 4-hr basis) and 485.5 mmBtu/hr on a 24-hr basis. The boiler primary fuel will be sugarcane bagasse and sweet sorghum bagasse. Biomass consisting of energy crops, wood chips and vegetative debris will be used as a supplemental boiler fuel. Natural gas will be used as a startup, shutdown and flame stabilization fuel and during a disruption in the biomass supply.

A simplified process flow diagram for the steam and power operations including proposed pollution control equipment is shown in Figure 7.

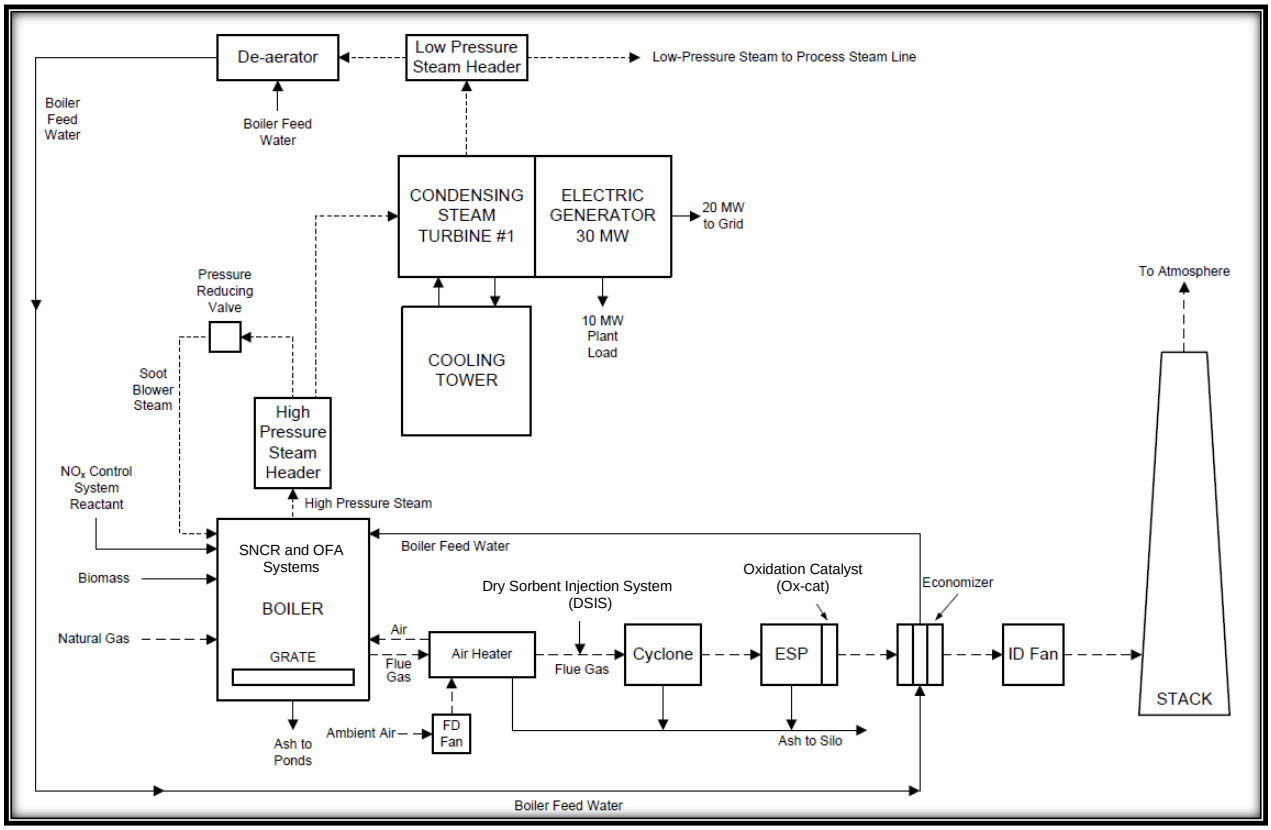


Figure 7 – Simplified Diagram of Applicant's Proposed HEF Steam and Electricity Production Cycles

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

- Selective non-catalytic reduction (SNCR) based on urea [$(NH_2)_2CO$] or ammonia (NH_3) injection and a high performance overfire air (OFA) system for minimizing emissions of nitrogen oxides (NO_X);
- Low-NO_X burners (LNB) for firing natural gas;
- 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 natural gas will also control emissions of mercury (Hg) and lead (Pb);
- The modern OFA system will also control emissions of carbon monoxide (CO) and volatile organic compounds (VOC);
- Oxidation catalyst (Ox-cat) will be used to provide further CO and VOC control as well as control of organic hazardous air pollutants (HAP).

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 and sulfuric acid mist (SAM – H_2SO_4) 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).

2.3. (E.U. 003) Cooling Towers

The proposed HEF facility will utilize up to three mechanical draft cooling towers. The cooling towers will be used for the cooling of miscellaneous machinery, the condensing set and the process equipment used in ethanol production at the HEF facility. The design parameters for the cooling towers are: one cell with a stack height of 35 feet, a combined circulating water flow rate of 34,000 gallons per minute (gpm), a temperature of 77 °F and a design drift rate of 0.001%. Cooling tower make up water will be primarily a suitable recycled process water stream. Cooling tower blowdown will be treated to remove accumulated dissolved solids and then reused for cooling tower makeup.

2.4. (E.U. 004) Ethanol Process

The ethanol process is shown in Figure 8 and consists of juice extraction, evaporation, fermentation, distillation and dehydration. The process description is paraphrased from the application.

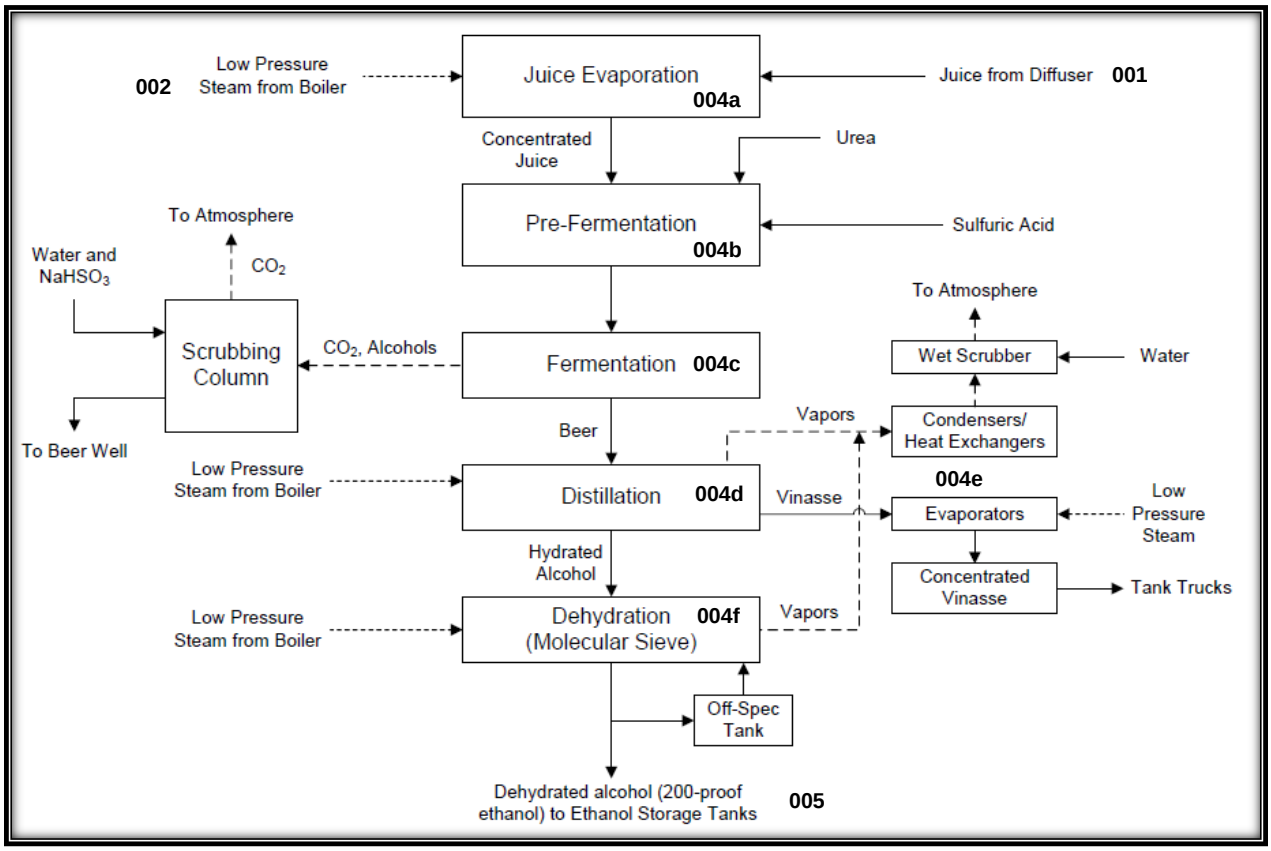


Figure 8 – Simplified Diagram of the HEF Sugarcane and Sorghum to Ethanol Production Process

Juice Evaporation (004a). The evaporation process concentrates the sucrose juices extracted in the diffuser. The extracted juice is pumped from the juice storage tank to a five-effect multiple-effect evaporator, where the juice is concentrated from 14% to 22% total solids. The concentrated juice is stored in the concentrated juice storage tank. The steam condensate is recovered and returned to the boiler feed water system. The condensed vapor condensate is collected and is then pumped to the diffuser as imbibition water for juice extraction.

Pre-fermentation (004b). Concentrated juice from the concentrated juice storage tank is first cooled using the beer feed to distillation followed by a trim heater using cooling water. The cooled, concentrated juice along with the yeast and urea (added as a nutrient) are fed to an agitated pre-fermenter. The pre-fermenter serves as a yeast propagator and initially acclimates the yeast to the fermentation conditions. Sulfuric acid is used to adjust the pH. The pre-fermenter continuously recirculates the ferment through a heat exchanger to keep the temperature in the optimum range for fermentation.

Fermentation (004c). During fermentation, sugars contained in the concentrated juice are transformed to ethyl alcohol, carbon dioxide (CO_2) and various secondary products. Secondary products include other alcohols, aldehydes, glycerin, etc. There are a total of four agitated fermenters in series, each having controlled temperature and controlled additions of urea and yeast to maintain optimum fermentation conditions. The ferment is continuously transferred from the pre-fermenter to the first fermenter based on level. Flow is maintained from one fermenter to another based on level.

The product of fermentation, called "beer," is a weak ethanol solution and contains the residue of fermentation components. The beer is pumped to a holding tank, designated as the beer well. The alcohol concentration in the clean beer is generally 8%. Solid substances include yeast, bacteria, non-fermentable solids, mineral salts, albuminoidal substances and other miscellaneous substances. Dissolved gases include CO_2 and SO_2.

The off-gases from the fermentation vessels are collected and sent to a packed scrubbing column, called the CO_2 scrubber. The CO_2 scrubber uses water, fortified with sodium bisulfite ($NaHSO_3$), to remove water soluble components, such as ethanol, and to chemically remove acetaldehyde. The off-gases, which are composed primarily of CO_2 with minor traces of ethanol and other organic compounds, are released to the atmosphere. The CO_2 scrubber effluent is sent to the stripper column for removal of ethanol and related compounds.

The following equipment will be used in steps 004b and 004c: rotary screens; juice evaporator; clean and foul condensate tanks; a sulfuric acid tank; a urea tank; yeast mixing tank; pre-fermenter; pre-fermenter cooler; fermenters; fermenter coolers; beer well tank; beer/sucrose heat exchanger; and CO_2 scrubbing column.

Distillation (004d). From the beer storage, the beer is sent to a pre-heater and then to a beer/stillage heat exchanger. The gas removed in the degassing column is cooled, scrubbed in the distillation scrubber and then released to atmosphere. The beer column overhead is transferred in the vapor phase to the rectifier column.

The alcohol stream is increased to 91% by weight ethanol concentration in the rectifier column. Rectifier overhead vapor is sent to the molecular sieve units to further remove water to less than 0.7% by weight in the ethanol product. Propanol and fusel oils are removed from the lower section of the rectifier column and combined with the 91% ethanol vapor which goes to the molecular sieves.

Rectifier bottoms are sent to a stripper column to strip remaining traces of ethanol from the rectifier bottoms. The bottoms from the stripper column are comprised of almost pure water, and are reused in the process. The stripper column overhead vapor is sent back to the rectifying column.

The following equipment will be used in step 004d: beer distillation column; degassing column; degassing condenser; stripping column; rectification column; heat exchangers; fusel oil decanter; hydrated alcohol tank; CO_2 washing column; and scrubber water degasser.

Vinasse Evaporation (004e). The beer column bottom stillage, called vinasse, is cooled using the incoming beer as the heat sink and sent to storage. From the storage, the vinasse is evaporated to 40% solids using a combination of several waste heat sources and live steam in three sets of multiple effect evaporators. The concentrated vinasse is stored and then loaded onto trucks for shipment to be utilized for animal feed.

Vinasse evaporator vapor condensates will normally be less than 3,000 parts per million (ppm) chemical oxygen demand (COD) with 70 pounds per hour (lb/hr) dissolved solids, 26 lb/hr alcohol and 44 lb/hr liquid fermentation byproducts. The condensed vinasse vapor condensate stream will be processed as necessary for reuse as cooling tower make-up.

The zeolite beds must be regenerated periodically by vacuum. The molecular sieve bed being regenerated is first isolated from the incoming hydrated ethanol steam and the inlet of this bed is valved to a regeneration condenser. A purge stream consisting of a portion of the dehydrated product from the on-

line molecular sieve is fed into the outlet of the regenerating molecular sieve. The non-condensable vapors from the regeneration condenser are removed via a two-stage steam ejector or a liquid ring vacuum pump. The cooled non-condensable vapors are then fed to the distillation vent scrubber. The condensed liquid from the regeneration condenser is reclaimed by sending it back to the rectifier column.

The following equipment will be used in step 004e: multiple effect evaporators; raw and concentrated vinasse storage vessels; and a load out system.

Dehydration (004f): The final stage in the ethanol production process is dehydration. Hydrated alcohol from the distillation process, at about 96% by volume alcohol, undergoes dehydration with a molecular sieve to produce ethanol at 99.3% by weight purity. The process is performed in a continuous operation where the hydrated alcohol is superheated by steam in a shell and tube heat exchanger to ensure that the ethanol stream is always in the vapor phase as it passes through molecular sieve zeolite beds. The final ethanol product is condensed, cooled, and sent to the 200-proof storage tank.

The following equipment will be used in step 004f: hydrated alcohol heater; zeolite absorber (molecular sieve); condensers and coolers; filter; dehydrated alcohol holding tank; and tie-in to CO_2 washing column.

Air Pollution Control Equipment. Two wet scrubbers will be used in the ethanol production area to control emissions of ethanol, other VOC and organic HAP. One will be incorporated into the fermentation step (with $NaHSO_4$) and the other will be incorporated into the distillation and dehydration steps. According to the applicant, the two scrubbers will have ethanol/VOC removal efficiencies of 98%.

2.5. (E.U. 005) 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 and are subject to Title 40 of the Code of Federal Regulations (CFR), Part 60, Subpart Kb (40 CFR 60, Subpart Kb):

- One fuel ethanol storage tank with a capacity of 1,000,000 gallons (gal);
- One 200 proof ethanol storage tank with a capacity of 100,000 gal;
- One off-specification (off-spec) tank with a capacity of 100,000; and
- One denaturant/gasoline tank with a capacity of 100,000 gal.

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

- One corrosion inhibitor tank with a capacity of 2,500 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.

2.6. (E.U. 006) Truck and Rail Loadout and Flare

Loading racks will be used to load out denatured fuel ethanol from the product storage tank to trucks and railcars. In-line blending for gasoline and ethanol to produce a denatured product may also take place at the loading rack. One loading rack will be provided for trucks, and one for railcars. The maximum truck loading rate of each rack will be 600 gpm. During ethanol loadout, ethanol and gasoline vapors can be generated. The vapors are sent to the loading racks flare for destruction. The loading racks and the flare will be permitted to operate up to 3,120 hr/yr. A truck loading rack will be used to load ethanol and ethanol blends from the product storage tank to trucks. 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.

2.7. (E.U. 007) Miscellaneous Materials Storage Silos

Materials storage silos will be installed to store material for the DSIS and to store ash, as well as lime for the water treatment system. Each silo will be controlled by a baghouse or a bin vent filter.

2.8. (E.U. 008) Emergency Equipment

There will be one diesel or natural gas-fired electric generator of 2,000 kilowatt (kW) capacity, for purposes of supplying electric power to the facility during a black start or a power failure. The generator will be limited to 500 hr/yr of operation during emergencies and 100 hr/yr for maintenance and testing. There will be one diesel or natural gas-fueled 600 horsepower (hp) diesel fire pump will also be installed to provide firewater during emergencies. This engine will be limited to 500 hr/yr of operation during emergencies and 100 hr/yr for maintenance and testing.

2.9. (E.U. 009) 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.

2.10. 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, F.A.C., a facility is considered a "major stationary source" if it emits or has the potential to emit (PTE) 250 tons per year (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 HEF 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*), *"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 HEF to be a major stationary source if it emits or has the potential to emit 250 TPY or more of any PSD pollutant. On July 27, 2011 the Department held a workshop for the purpose of initiating rulemaking to revise Rule 62-210.200(189) consistent with the federal definition. See link to Ethanol Rule Project .

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, 4]

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 and NO_X).
3. Ozone (O_3) is regulated by its precursors (VOC and NO_X).
4. There is a federal SER of 75,000 TPY for Greenhouse Gases (GHG) as carbon dioxide equivalent (CO_2e) that has not been incorporated into Department rules. However, the applicability to the CO_2 component of GHG emissions from bioenergy and biogenic stationary sources was recently deferred by EPA until the second half of 2014. Refer to: Link to Final CO2 PSD Deferral .

$PM_{2.5}$ is also a Federal PSD pollutant and the Department is in the process of adopting a SER of 10 TPY. Refer to Link to $PM_{2.5}$ Rule . Until the rule is finalized, projects in Florida are not subject to a SER for $PM_{2.5}$.

Table 4 summarizes the applicant's estimates of key PSD pollutants from the proposed HEF 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 85% of all PSD-pollutants to be emitted from the HEF facility. The facility will also emit approximately 32.3 TPY of NH_3 (not a PSD-pollutant) largely due to injection of urea to control NO_X emissions.

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

Operation/EU	CO	NO_X	PM/PM_{10} [1]	$PM_{2.5}$ [1]	SO_2 [4]	SAM[5]	VOC	Hg[3]	Pb
Biomass Material Handling (001)			7.9/1.8	0.3					
Boiler (002)	552.9	184.3	27.6/27.6	18.0	200.4	9.8	31.3	0.025	0.18
Cooling Towers (003)			0.37/0.19	0.19			0		
Ethanol Production (004)							87.6		
Storage Tanks (005)							3.9		
Product Loadout and Flare (006)	5.64	1.04	0.052	0.052	0.009		7.0		
Miscellaneous Storage Silos (007)			0.85	0.85			0		
Emergency Equipment (008)	1.29	8.84	0.087	0.087	0.0063		0.26		
Fugitive Equipment Leaks (009)							6.5		
Totals	559.8	194.2	36.9/30.6	19.5	200.4[4]	9.8[5]	136.6	0.025[3]	0.18
SER	100	40	25/15	(10) [2]	40	7	40	0.1	0.6
PSD Applies? (Yes/No)	Yes	Yes	Yes	No [2]	Yes	Yes	Yes	No	No

1. Estimates based on filterable (front-half sampling train) material and do not include condensable (back-half) material.
2. 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.
3. Uncontrolled estimate equals 50 pounds Hg per year (lb/yr). Applicant expects much lower emissions.
4. SO_2 emissions will be approximately 109.3 TPY pursuant to the Department Draft BACT determination.
5. SAM emissions will be approximately 6.8 TPY pursuant to enforceable limit in Draft permit that avoids PSD.

In summary, the HEF project will emit at least 100 TPY of at least three PSD pollutants (SO_2, NO_X and VOC) and at least 250 TPY of CO. 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 HEF 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 [e.g. NO_X, SO_2 and VOC].

For reference, the applicant has requested a federally enforceable limit on natural gas consumption to insure that the project will not trigger the 75,000 TPY CO_2e SER for GHG even after exclusion of the CO_2 component of bioenergy/biogenic emissions from bagasse use in the boiler.

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 HEF facility will be a Title V source based on emissions of regulated air pollutants regardless of HAP emissions.

3.5. HAP Major Source Non-Applicability 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 HEF facility. The main source of HAP is the boiler. The greatest single HAP emitted from the biomass boiler is HCl at 6.85 TPY followed by chlorine (Cl_2) at 3.03, formaldehyde at 2.69 TPY and benzene at 2.17 TPY. The other key HAP emission (> 1 TPY) is acetaldehyde from the ethanol process at 2.87 TPY.

According to the applicant's estimate, the facility (boiler and other processes) does not constitute a major source. 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 were to equal or exceed the 10 or 25 TPY HAP thresholds, then the boiler would ultimately be subject to the Boiler NESHAP pursuant to 40 CFR 63, Subpart DDDDD, which was revised on March 21, 2011. See Revision to Subpart DDDDD . The rule (for which implementation has been delayed) includes very stringent PM limits as well as specific limits for Hg, HCl and D/F.

Table 5 – Applicant's Initial Estimates of PTE of HAP from the HEF Project in TPY

Pollutant	HCl	HF	Cl_2	Key Metal HAP [1]	Key Organic HAP [2,3]	Other HAP	Total
Boiler	6.85	0.04	3.03	1.05	7.11	0.18	18.26
Ethanol Process					4.24		4.24
Other Sources						0.67 [4]	0.67
Total	6.85	0.04	3.03	1.05	11.35	0.85	23.17

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 acetaldehyde (C_2H_4O), acrolein (C_3H_4O), benzene (C_6H_6), Bis(2-ethylhexyl) phthalate ($C_{24}H_{38}O_4$), formaldehyde (CH_2O), styrene (C_8H_8), toluene (C_7H_8) and 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.

On May 18, 2011 EPA delayed the effective date of Subpart DDDDD until proceedings for judicial review of this rule are completed or the EPA completes its reconsideration of this rule, whichever is earlier. See Delay of Subpart DDDDD .

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

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 HEF 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 HEF 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.

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);
- 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 008); and
- 40 CFR 60, Subpart VVa – VOC Equipment Leaks from SOCMI Processes (EU 002, 003,004, 005, 006, 007 and 009).

The boiler (EU 002) will combust a fuel feed stream containing approximately 10% (much less than 30%) of materials (e.g. vegetative waste) that could be construed to be municipal solid waste (MSW). Therefore the HEF 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 Vercipia Ethanol project (and by extension to the HEF) that processes 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);
- 40 CFR 63, Subpart JJJJJJ – Industrial, Commercial, and Institutional Boilers Area Sources; 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.

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 applicant-proposed and 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 (applicable to major sources of HAP); 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 (until completion of ongoing Department rulemaking) 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 primarily cane bagasse, which is clearly fuel and not a waste in this industry. Only the wood chips and vegetative debris (which will comprise no more than approximately 10% of the fuel) could be construed to be waste. 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". The furnace is not specifically designed to burn wastes though it is capable of burning some waste as supplementary fuel. The Department concludes that neither he term the term "incinerator" nor the incinerator rule applies to this project. Furthermore, this rule contains less stringent requirements than the applicable NSPS, NESHAP and case-by-case BACT.

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. The facility will typically burn 90% (or more) 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.

- Cane bagasse 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 HEF facility is not subject to CAIR. On July 6, 2011, EPA announced, but has not yet published in the Federal Register a rule known as the Cross-State Air Pollution Rule (CSAPR) that will replace CAIR. The HEF facility is not subject to the Cross-State Air Pollution Rule (CSAPR), because its biomass boiler is a cogeneration unit that will sell less than 219,000 megawatt hours (MWh) per year of electricity to the grid. Details are available at the following link: Pre-publication CSAPR .

4. BACT REVIEW

Based on the applicant's emission estimates, 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 because 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, and NO_X).

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 feedstock and Biomass Handling (EU 001)

PM/PM_{10} Emissions

Discussion. PM/PM_{10} represent 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 9 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.

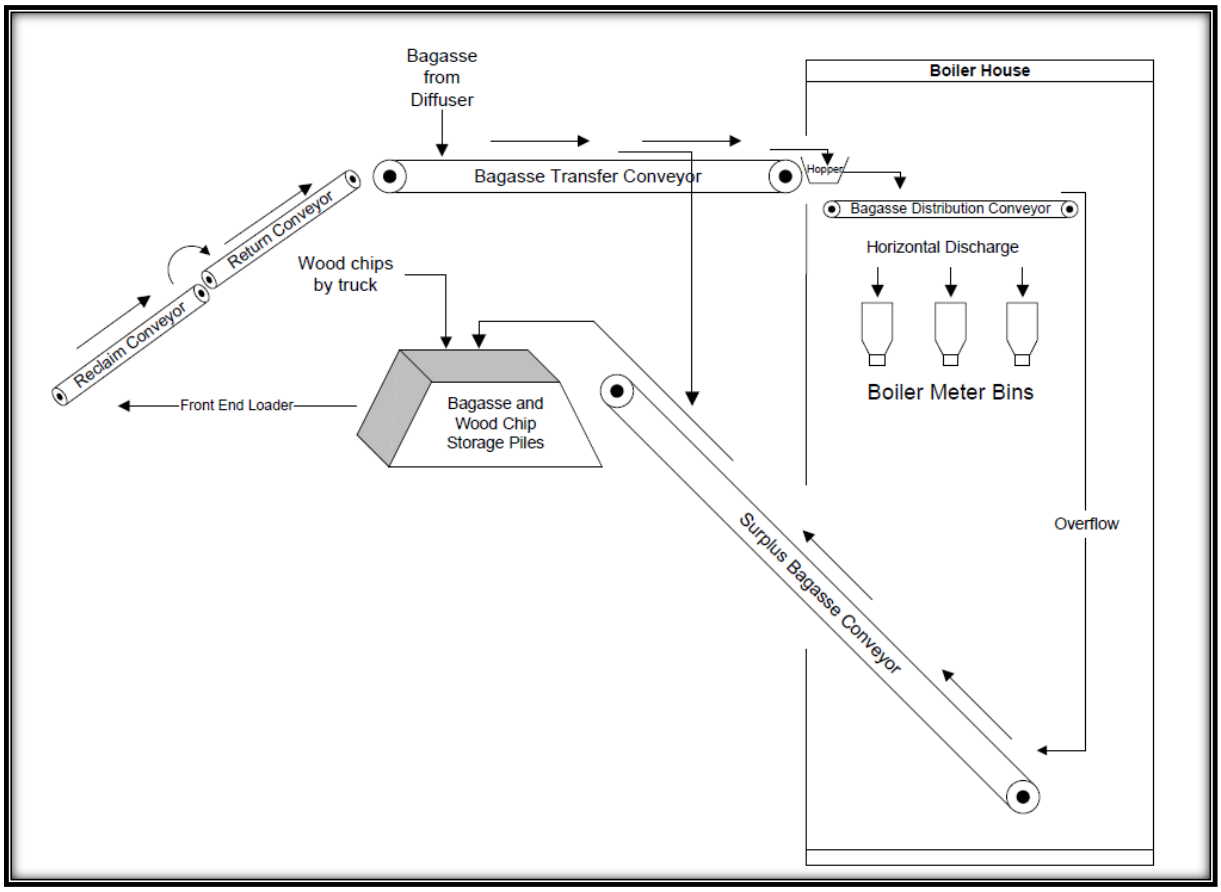


Figure 9 - Boiler Biomass Feed System

The boiler biomass (bagasse and supplemental) will be stored in piles located in the biomass yard in the southwestern quadrant of the HEF site as shown in Figure 3. 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. HEF 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 as needed to prevent fugitive dust emissions.

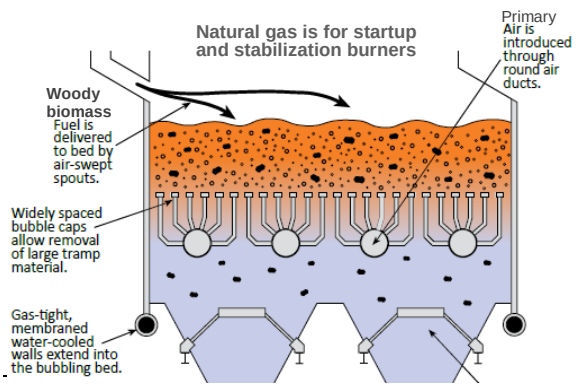
4.2. BACT Review for Biomass-Fueled Boiler (EU 002)

NO_X Emissions

NO_X Formation and Primary Control.

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

Bubbling Fluidized bed (BFB) Boiler Principles. The applicant proposes to install a grate stoker boiler and not a BFB boiler. However, it is useful to discuss the alternative design of a BFB boiler due to its inherently lower emission characteristics. Details of the bed portion of a Babcock and Wilcox (B&W) BFB are provided in Figure 10. Figure 11 is an internal diagram for the typical furnace configuration of a HYBEX BFB biomass boiler such as offered by METSO Power.



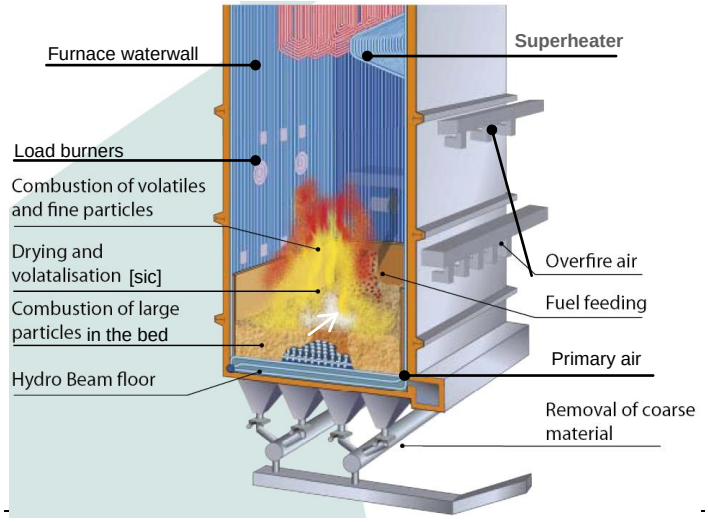


Figure 10 – Bed Description for B&W BFB Boiler **Figure 11 – Typical METSO HYBEX BFB Boiler**

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

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

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:

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

Where:

i = 1, 2, 3

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

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

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

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

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:

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

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

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.

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

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

$$CharC + O_2 \rightarrow NO + ...$$ 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 12 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.

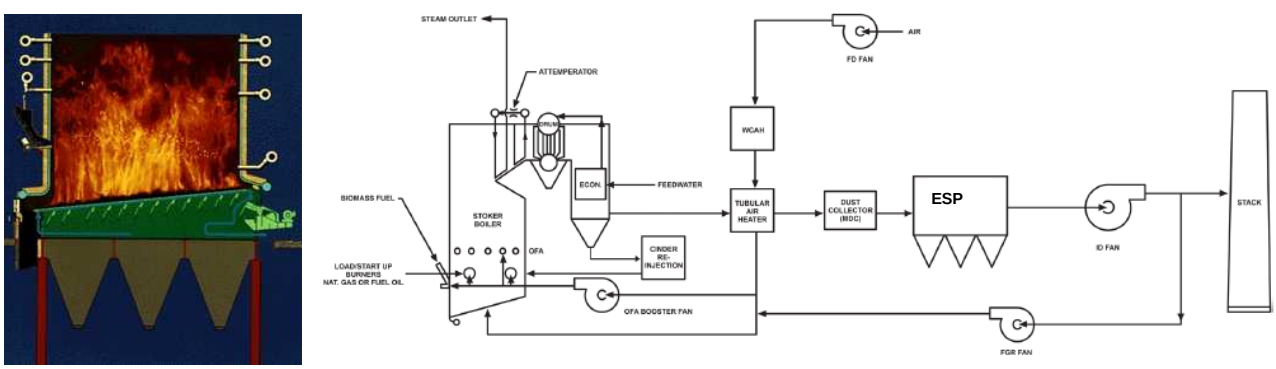


Figure 12 – Detroit Hydro-Grate and Typical Stoker-based Process Schematic

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 BFB.[1]

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

[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 a previous applicant (Southeast Renewals Fuels), "the spreader stoker technology results in inherently higher uncontrolled NO_X emissions compared to the fluidized bed boiler".[2] The Department agrees with the stated B&W and HEF 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™) [3].

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

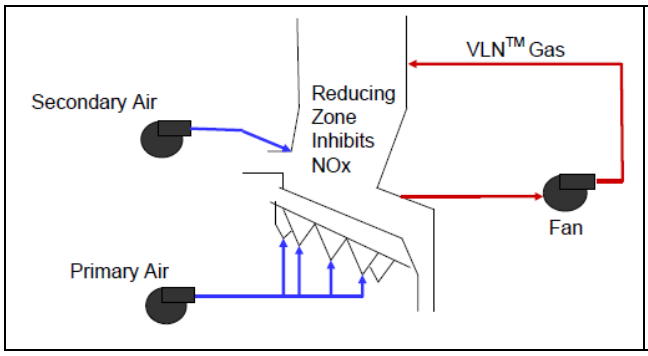


Figure 13 – Diagram of the VLN™ Process

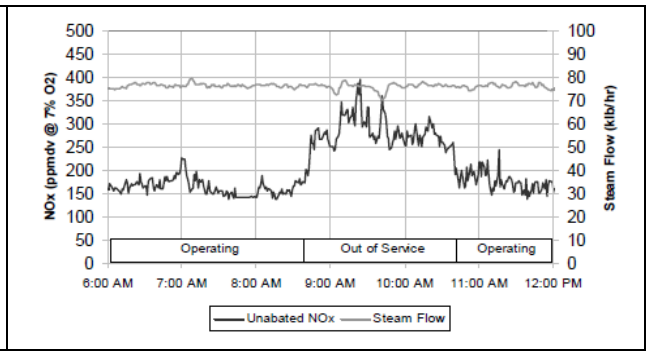


Figure 14 – Operation with/without/with VLN™ System

[2] 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.

[3] 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.

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.

HEF has proposed to build a stoker boiler but with volatilization, drying and partial combustion occurring above the grate in a manner analogous to that shown in the BFB diagram in Figure 11.

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.[4] The Department estimates that this equates to 300 coal-fueled units each of 400 MW capacity or nearly 5,000 HEF-sized (30 MW) units.

Refer to Figure 15 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.

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

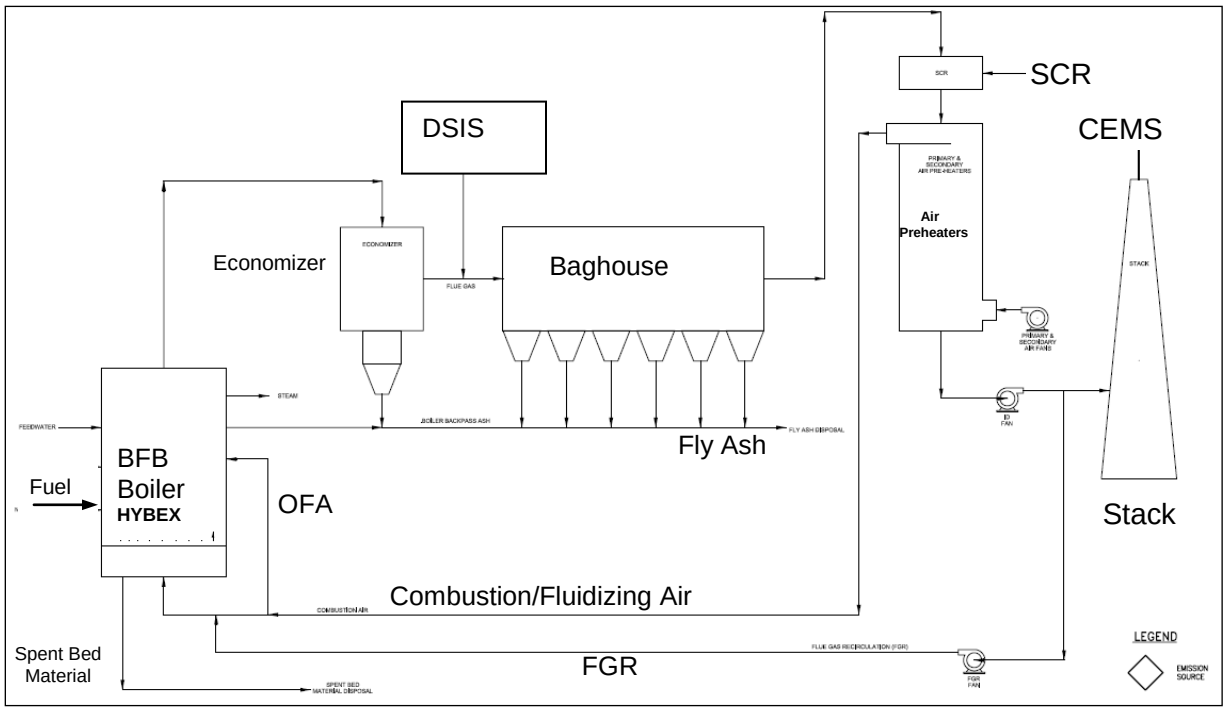


Figure 15 – Gainesville Renewable Energy Center (GREC) BFB Pollution Control Technologies

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 16, reheat is incorporated into the clean-side SCR system at an existing 36 MW poultry litter and feathers-to-energy facility in Holland.

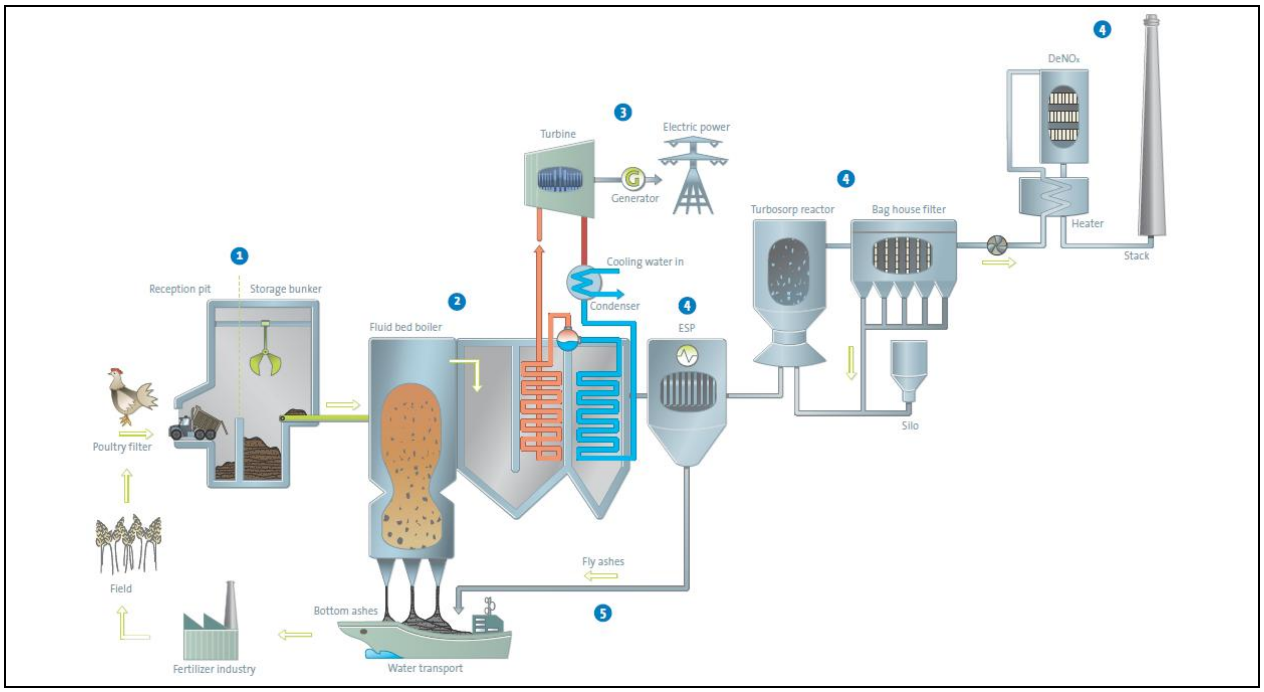


Figure 16 – Basic Process and Air Pollution Control Equipment Diagram for Moerdijk BFB Boiler

Refer to Figure 17.[5] 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.

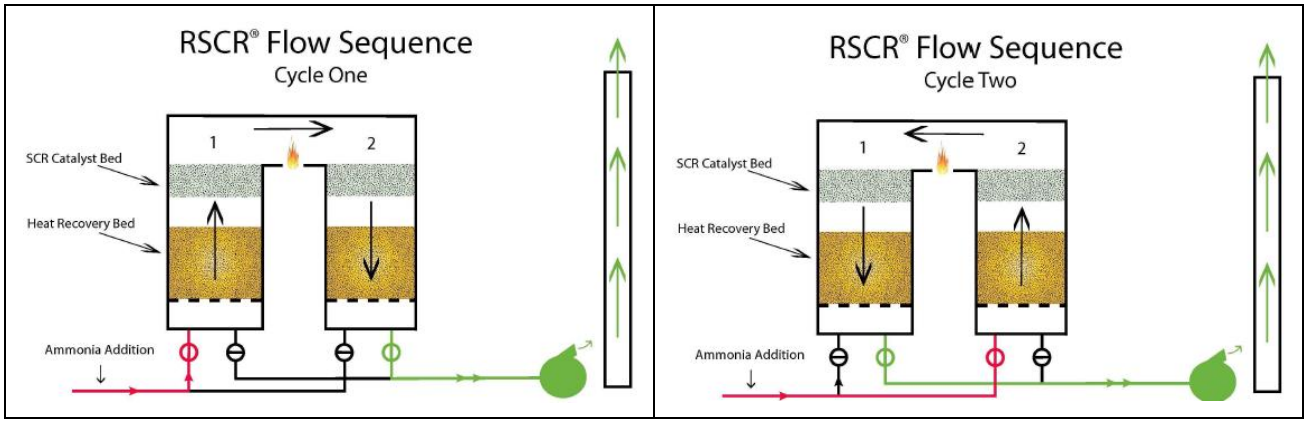


Figure 17 - Principle of RSCR incorporating Duct Burner and Thermal Media (Ox-cat not shown).

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.

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 15 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 (Boralex Stratton and Boralex Fort Fairfield) and New Hampshire (Whitefield Power and Bridgewater Power).[6]

RSCR was also installed at a facility in Vermont (McNeil Burlington).[7] 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.[8, 9] 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.[10]

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

6 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.

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

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

9 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.

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

In addition to CRI, Haldor Topsoe (HT) supplies low temperature SCR catalyst without requirement for exhaust gas reheating.[11] CRI claims the SCR catalyst as an effective system to reduce dioxin and furan (D/F).[12]

Control of D/F is corroborated in the literature as well as destruction of VOC.[13, 14] 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:[15]

"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".*[16] 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 Department conducted a BACT determination for NO_X and D/F at the Palm Beach Renewable Energy facility and required SCR to control both pollutants.

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.[17] 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:

"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."[18]

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.

<u>Applicant's Proposal for NO_X.</u> Refer to Table 6. The applicant's BACT proposal is 0.10 lb/mmBtu on a 30-day rolling basis based on selection of a stoker boiler and incorporation of GCP and SNCR.

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[11] Baviro Roosendaal Web Link. www.baviro.nl/SCR_nl.html .

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

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

[14] 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

[15] 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

[16] 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

[17] Telecom. Heron, T., Florida DEP and York, D., Whitefield Power. August 2, 2010.

[18] 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} [f,c]	SO_2
HEF, Highlands County [h] ethanol and power grate stoker - cane bagasse, energy crops, wood chips, vegetative debris 504/486 (4/24-hr) mmBtu/hr (2011)	**0.30** 30-day GCP + Ox-cat	**0.017** stack test GCP + Ox-cat	**0.10** 30-day SNCR	**0.015 (f)** stack test ESP	**0.11**[h] 12-month DSIS
SRF, Hendry County Ethanol and Power, BFB or grate Sorghum bagasse, wood, biogas, VLSD fuel oil, propane, yard waste < 30%. 488 mmBtu/hr (2010)	0.10 (grate) 0.10 (BFB) 30-day GCP or Ox-cat	0.010 (grate) 0.010 (BFB) stack test GCP or Oxcat	0.10 (grate) 0.08 (BFB) 30-day SNCR or SCR	0.015 (f) (grate) 0.015 (f) (BFB) stack test ESP	0.060 30-day DSIS
Vercipia, 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	0.060 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) [e] 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 (2010)	0.12/0.08 [a] 30-day GCP	~0.010/0.009 [a] 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
NSPS Subpart Db Propane, wood, ULSD fuel oil ≤250 mmBtu/hr	No standard	No standard	~0.020	0.030 (f) or 20% opacity [b]	~0.020
40 CFR 63, Subpart DDDDD (major)	~1.57 (eq)	No standard	No standard	0.0011 (f)	No standard
40 CFR 63, Subpart JJJJJJ (area)	No Standard	No standard	No standard	0.03 (f)	No standard

a. The lower CO and VOC values for the Gainesville Renewable Energy Center (GREC) apply after one year of operation.
b. 20% opacity except for one 6 minute period per hour of 27% opacity.
c. "c" denotes condensable fraction.
d. The high Subpart DDDDD CO values are for the hybrid suspension grate category. Rule also includes Hg, HCl, D/F limits.
e. "eq" values in lb/mmBtu denote cases where the enforceable limits are actually in other units such as ppm, lb/hr or TPY.
f. "f" denotes filterable fraction.
g. Subpart JJJJJJ includes only a PM limit and no Hg, HCl, D/F limits.
h. Limits proposed by HEF. All were accepted except for SO_2, which will be limited to 0.06 lb/mmBtu on a 30-day basis.

One of the key statements in support of their proposal is the claim that "lending institutions are not willing to lend significant amounts of capital for unproven (presumably SCR) technology configurations".

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. Furthermore the key feature of the stoker grate designs for bagasse stokers is drying, volatilization and partial combustion in suspension (prior to falling on the grate). The suspension feature is clearly part of the BFB design as shown in Figure 11 above.

Consideration of a BFB boiler versus a grate stoker with suspension drying, volatilization and partial combustion (combustion technique) is within the scope of a BACT definition and review. BACT also includes treatment techniques and a combination of such techniques can improve the emission profile of a stoker to a level where is equals that of a BFB boiler. Therefore it is allowable to specify a BFB boiler as the basis of BACT emission limits while allowing installation of a stoker boiler.

The Department accepts the applicant's BACT proposal for this project of 0.10 lb NO_X/mmBtu (30-day average) on the basis of incorporating GCP and SNCR in a stoker boiler. Compliance will be demonstrated by a NO_X-Continuous Emission Monitoring System (CEMS). Inclusion of Ox-cat to control CO, VOC and HAP will provide flexibility to achieve the NO_X BACT by GCP and SNCR. The Department does not reject BFB and SCR and these remain options for consideration in future projects.

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 likely to be controlled (after installation of Ox-cat as discussed below) to levels less than the federal PSD SER of 250 TPY for this particular industry (ethanol production facilities that produce ethanol by natural fermentation).

SO_2 and SAM Emissions

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 application, the biomass boiler is expected to emit approximately 200 TPY of SO_2 and 10 TPY of SAM.

According to the applicant, biomass entering the ethanol process (e.g. sugarcane and sweet sorghum bagasse) at HEF will be typically low in S content. Values of 0.12% and 0.22% S (dry basis) were provided as design values for sugarcane and sweet sorghum respectively. The contribution from natural gas is negligible (<0.002%) compared with bagasse.

Applicant's Proposal for SO_2 and SAM:

The applicant's proposed SO_2 BACT limit for the bagasse boiler for biomass firing is 0.11 lb/mmBtu on a 12-month rolling average. According to the applicant, this limit is somewhat higher than other bagasse boilers (i.e., 0.06 lb/mmBtu), but this is due to the potentially higher sulfur content of sweet sorghum bagasse.

The proposed BACT limit for SO_2 is based on: the DSIS using sodium bicarbonate (SBC or $NaHCO_3$) or a proprietary chemical; the low sulfur content of bagasse, wood, and natural gas; and some inherent SO_2 removal via fly ash collected in the ESP. According to the applicant, the inherent control (i.e. without DSIS) via the fly ash and ESP is estimated to be at least 75%.

The applicant did not propose a specific BACT limit for SAM but proposes the SO_2 controls discussed above for control of SAM.

Department's BACT Determination for SO_2. The proposed value of 0.11 lb/mmBtu on a 12-month basis, rolled monthly is high compared with all of the other projects listed in Table 6. For example, the two sorghum-to-ethanol projects listed in the table are each limited to 0.060 lb/mmBtu. The SRF project, e.g., will use *more* sorghum than intended by HEF thus contradicting the claim that the *"somewhat higher (limit) …… is due to the potentially higher sulfur content of sweet sorghum bagasse (vs. sugarcane)"*.

U.S. Sugar Unit 8 burns sugarcane bagasse in a grate boiler, is equipped with an ESP and has no add-on SO_2 control such as a DSIS. Unit 8 was limited to and achieves less than 0.06 lb SO_2/mmBtu based on annual testing. Similarly, the New Hope Power Okeelanta facility permitted in the early 1990's has three grate boilers that burn sugarcane bagasse and woody wastes. These are also equipped with ESP and no add-on control equipment for SO_2. All of the New Hope Okeelanta boilers achieve less than 0.060 lb SO_2/mmBtu on a 30-day basis as measured by SO_2-CEMS. The following figure contains the 30-operating day rolling values for the three units over the past year. Flat zones are periods when a unit or CEMS is down.

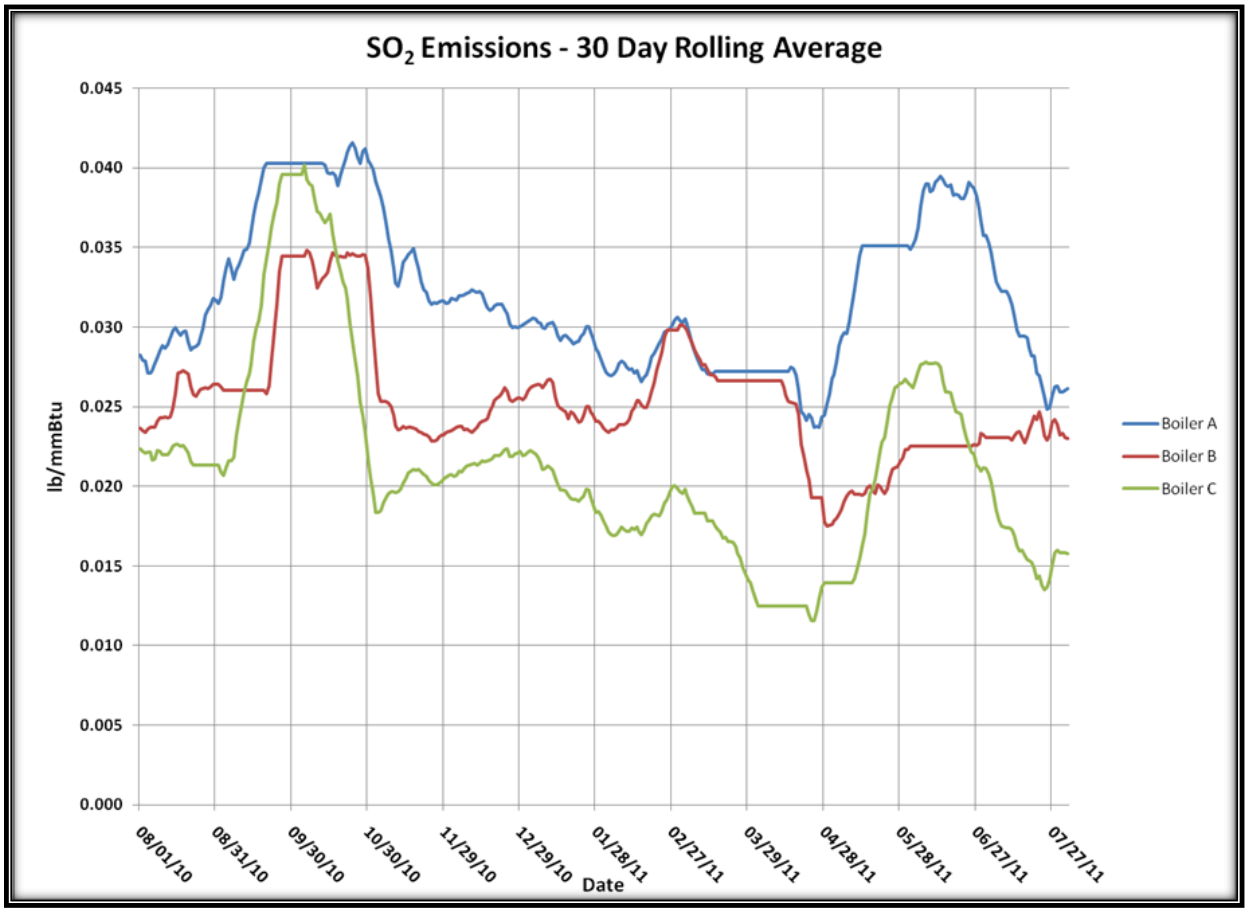

Figure 18 – SO_2 Emissions on a 30-Operating Day Basis at Okeelanta Units 1, 2 and 3

According to the University of Florida study cited by the applicant as a source of chloride (Cl) content, washed sorghum bagasse had a content of only 0.01% S. It is reasonable, given the presence of the DSIS, to expect HEF to comfortably achieve a value of 0.06 lb/mmBtu on a 30-day basis like U.S. Sugar Unit 8, Okeelanta Units 1, 2 and 3 as well as the proposed Vercipia and SRF projects. Also given the expectation by the applicant that a reduction of 95% in HCl emissions will be achieved by use of the DSIS, it is also reasonable to expect a relatively high efficiency for SO_2 as well.

The Department will set the BACT limit at 0.060 lb SO_2/mmBtu on a 30-operating day basis as measured by SO_2-CEMS. The control technology (low sulfur biomass, partial control via fly ash and the ESP, and the DSIS) proposed by HEF is acceptable. In addition to $NaHCO_3$, the permit will also indicate slaked

lime [$Ca(OH)_2$], trona [$Na_3(CO_3)(HCO_3)\bullet 2H_2O$] or other proprietary solid chemicals as possible sorbents for use in the DSIS.

Department's non-BACT determination for SAM.

Generally speaking, the DSIS will be as efficient in removing SAM as it is in removing HCl and more efficient in removing SAM than in removing SO_2. The following consolidated table is reproduced from a very recent paper on DSIS when used as a multi-pollutant control technique in conjunction with types of PM control devices to meet the boiler and utility MACT rules. [19]

Table 7 Pollutant Removal with DSIS in an ESP or a Pulsed Jet Fabric Filter Baghouse (PJFFB)

Pollutant	Typical % Removal		Sorbent	Comments
	ESP[1]	PJFFB[2]		
SO_2	70+	80+	Milled SBC Milled trona	If higher removal rates required, sorbent loading to ESP (or PJFFB) must be evaluated as well as PM loading leaving ESP (if selected).
HCl	90+	95+	Milled SBC Milled trona Unmilled trona Hydrated lime	High removal achieved when combined with SO_2 control.
SAM	90+	95+	Unmilled trona, Hydrated lime	Unmilled reagent is typical – SBC could be used, but significantly more expensive

1. Depends upon system residence time, hot or cold ESP, flue gas temperature, sorbent, sorbent coverage and sorbent particle size/reactivity.
2. Depends upon system residence time, flue gas temperature, sorbent, sorbent coverage and sorbent particle size/reactivity.

The SNCR system will require excess NH_3 to achieve the targeted NO_X removal efficiency of approximately 60% and will convert some of the SAM to ammoniated sulfates.

The Department will set a value equivalent to 0.0037 lb SAM/mmBtu (equal to 6.82 TPY) to insure PSD is not triggered. This value is equal to the limit recently set for the SRF project. 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 lower furnace occurs in substoichiometric conditions. Also, there often exist localized substoichiometric pockets or cells even if overall excess oxygen conditions are maintained in the lower furnace.

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.

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.

[19] Campobenedetto, E.J. and Silva, A.A., Babcock and Wilcox. Low Cost Multi-Pollutant Control Solution Demonstrations .Air & Waste Management Association Annual Conference. June 21, 2011.

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.

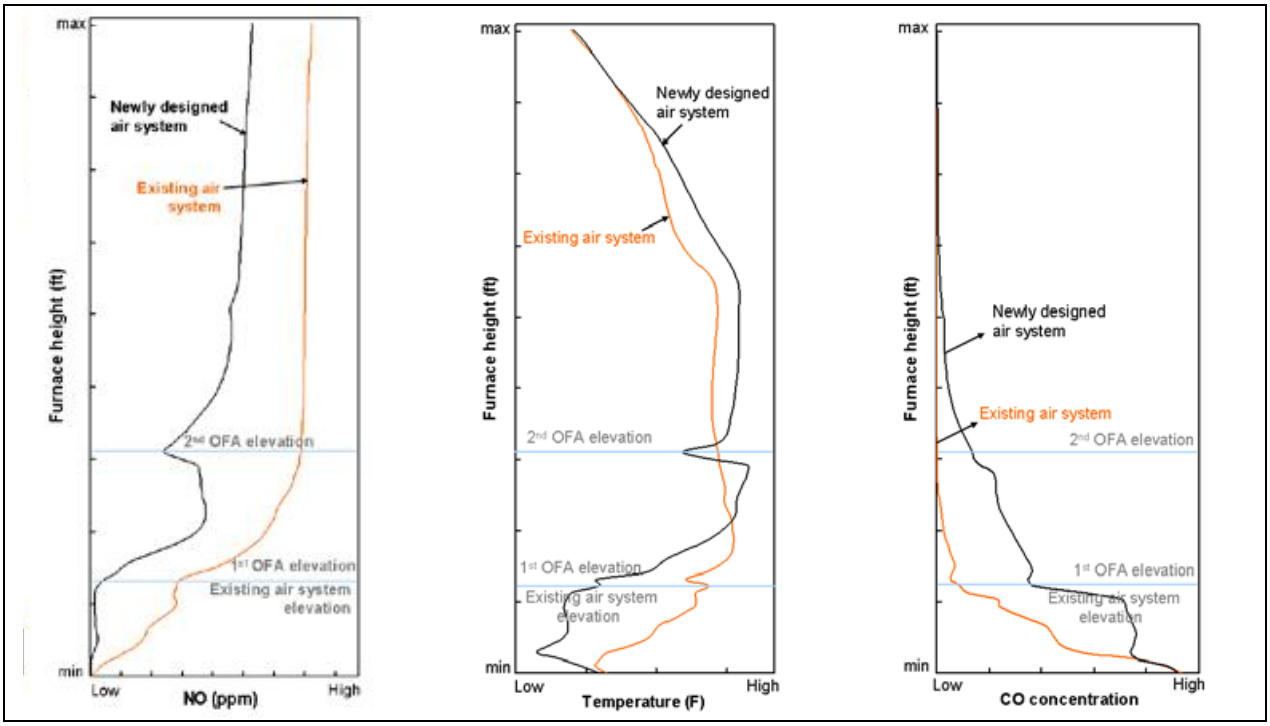

Figure 19 - Modeled NO_X, Temperature and CO a BFB Boiler after Switching to Low NO_X strategy.

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"*.[20]

If GCP are geared primarily to control NO_X (such as in the example above) then there is less freedom when also controlling CO and VOC by the same GCP. If GCP as discussed above 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 (e.g. ESP).

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.[21] Moreover, Ox-cat is even more effective in destroying formaldehyde (CH_2O - the HAP emitted in the greatest amount from the HEF boiler) than its effectiveness in destroying CO. Ox-cat is also effective in destroying D/F. Furans will oxidize quite easily. Dioxins will also be oxidized, but an accurate prediction of reduction is difficult to provide since its measurement is very specialized and expensive.[22]

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

The applicant's BACT proposal is 0.30 lb CO/mmBtu (30-day) and 0.010 lb VOC/mmBtu for by GCP within a hybrid suspension grate stoker. The applicant proposes a modern OFA combustion design and controls for boiler CO controls.

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[20] 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.

[21] Brochures. Süd-Chemie and Johnson-Matthey.

[22] Electronic Communication. Pope, M., Süd-Chemie to Linero, A., Florida DEP. Application of Ox-cat to Crop Biomass CO Emissions. August 9, 2010.

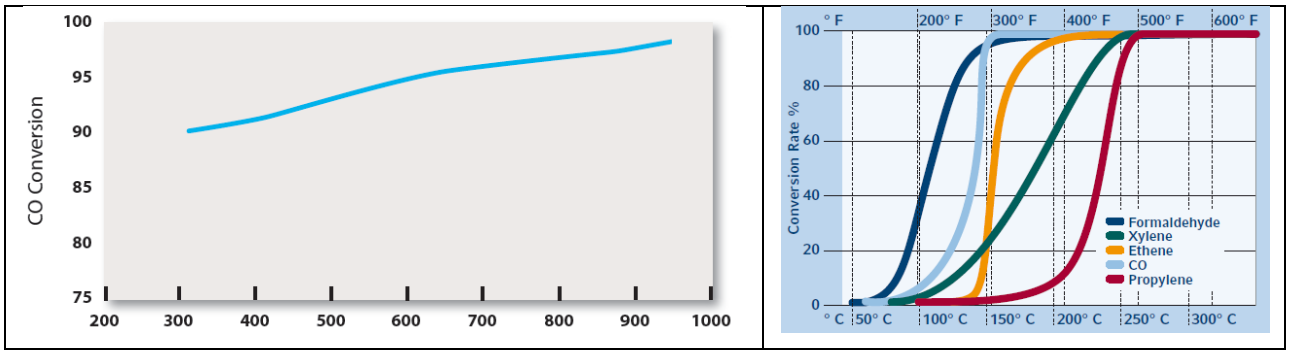


Figure 20 - Ox-cat Performance vs. Temperature (^{o}F) **Ox-cat Performance vs. Temperature (^{o}C)**

An enhanced OFA system (i.e. beyond the proposed modern OFA system) was evaluated and according to the applicant is not cost-effective at $3,400 per ton of CO removed and $3.1 million in capital costs.

According to the applicant, Ox-cat would reduce CO and VOC emissions by an estimated 60 percent, from 584.3 TPY to 239.6 TPY, for a 345 TPY reduction. The cost effectiveness of oxidation catalyst for CO and VOC control is $1,044 per ton of (CO + VOC) reduced. The cost of oxidation catalyst is therefore comparatively low.

According to the applicant, catalyst vendors are not willing to guarantee the catalyst for more than one year of operation. One key supplier (Süd-Chemie) provided the following assessment to HEF regarding their product:[23]

"Our recent wood gas installations have been operational (24/7) for over 3 years now with annual water wash cleaning. Generally we expect a full rejuvenation (chemical) will be needed within 3 - 4 years on these applications. On this application the flue gas derived from sugar cane waste at an ethanol plant is not in our realm of experience. Consequently, while we have absolute confidence in our catalyst coating, the potential of catalyst masking agents and poisons within the gas are unknown. The agents and poisons would reduce the life and performance of the catalyst. Of course this affects all catalysts in the same way.

"At this point we could not realistically guarantee performance beyond 12 months (8760 hours) and even then the presence of unknowns could reduce this further. Consequently the emissions level would need to be adjusted for this fuel type."

<u>Department's Review.</u> A comparison of the proposed CO and VOC values for the HEF project with other biomass projects is given in Table 6 above. With an SNCR system it is necessary to simultaneously pursue a furnace low NO_X strategy using GCP such that CO and VOC emissions can substantially increase. With SNCR (without SCR), the Department concludes that Ox-cat would be cost-effective to reduce CO and VOC emissions as concluded by the applicant (see discussion above).

By destroying organic HAP such as CH_2O, Ox-cat would provide further reasonable assurance that the facility is an area source of HAP as discussed in Section 3.5 above and yield BACT level CO and VOC emissions.

<u>Department's BACT Determinations for CO and VOC.</u> 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. 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).

[23] Letter. Pope, M., Süd-Chemie to Landers, L., PPC Industries. Application of Ox-cat to flue gas from sugarcane waste. June 22, 2011.

The Department has determined that BACT for this project is the requirement to install Ox-cat with a final permit CO and VOC limits to be set in the future. It is very likely that such an installation will reduce emissions of CO to the point that it is not a major stationary (PSD) source by the present federal regulations and the pending state rule. The initial permit limits will be 0.30 lb CO/mmBtu (30-day average) and 0.017 lb VOC/mmBtu. Although several projects listed in Table 6 have lower CO and VOC limits, the applicant's updated proposal is adequate given that the emissions are will actually be controlled to a level less than the federal PSD threshold of 250 TPY for this particular industry.

The Ox-cat system will be installed and tested for a 24 month test period to determine if catalyst poisoning occurs due to the bagasse fuels. At the end of the 24 month test period, a test report will be submitted to the Compliance Authority and the Department. The report will include:

- Daily averages of boiler operating parameters to include heat input, steam generation, fuel mixtures (cane bagasse, sorghum bagasse, supplemental biomass fuel and natural gas) and corresponding weights of each biomass and mmscf of natural gas burned as fuel used including each supplemental fuel (energy crops, wood chips and vegetative debris);
- Daily NO_X and CO CEMS data in lb/mmBtu and lb/hr, daily HCl CEMS data in lb/hr and lb/mmBtu, all HAP and VOC stack test results from both the boiler stack and ethanol process scrubber stacks in lb/mmBtu and lb/hr, all maintenance actions performed on the Ox-cat system; and
- If necessary, a recommendation for the Ox-cat system removal with supporting justification or any requested permit modification to allow the continued use of the Ox-cat system.

Based on all the data (boiler parameters, pollutant and HAP emissions and maintenance actions) in the test report, the Department will either adjust the CO and VOC emission limits downward to reflect the actual CO and VOC emission rates or allow removal of the Ox-cat system. If the Ox-cat system is removed, the CO emission limit will remain 0.30 lb/mmBtu on a 30 day rolling average basis and the VOC limit will remain at 0.017 lb/mmBtu.

Compliance with the CO limit shall be demonstrated by a CO-CEMS. Initial and annual VOC compliance tests will be required.

While the supplier and applicant have expressed some doubts regarding the lifetime of the catalyst, the Department notes that the biomass fired will be fairly consistent and there should be few unknown or unexpected species that will get past the ESP and poison the catalyst.

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

<u>Discussion</u>. $PM/PM_{10}/PM_{2.5}$ 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.

<u>Applicant's Proposal for $PM/PM_{10}/PM_{2.5}$ and VE Limits.</u> The applicant's BACT proposal for PM/PM_{10} is 0.015 lb/mmBtu for <u>filterable</u> (f) PM/PM_{10} based on an ESP (following a wet sand cyclone). According to HEF:

"Fabric filters are considered technically infeasible for application to the proposed bagasse boiler. There are only few known applications of a fabric filter to a grate-type biomass-fired boiler and the fabric filter was used due to the use of a spray dryer for SO_2 control.

"No hybrid suspension/grate bagasse-fired boiler is known to utilize a fabric filter. Further, serious concerns exist over the ability of a baghouse to operate long-term in a harsh environment with a flue gas containing significant moisture and light, stringy bagasse particles. There are also serious concerns with potential fire hazards due to burning particles being carried out of the boiler. This is the nature of bagasse-fired boilers, where the bagasse fuel is light and stringy. As a result, fabric filter technology was not further considered for the HEF."

HEF 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 of 0.015 lb(f)/mmBtu is less than the NSPS, Subpart Db limit of 0.03 lb(f)/mmBtu applicable to units that (like HEF) burn less than 250 mmBtu/hr of fossil fuel. The applicable PM limit in the area source NESHAP Subpart JJJJJJ is also 0.03 lb(f)/mmBtu.

The capacity of the HEF boiler is 504 mmBtu/hr (4-hr) for all fuels combined. For reference, the proposed PM/PM_{10} limit is equal to the limit of 0.015 lb(f)/mmBtu applicable to boilers (those subject the NSPS, Subpart Da) burning a variety of fuels including at least 250 mmBtu/hr of fossil fuels.

As discussed above, major source NESHAP, Subpart DDDDD is not applicable to this project and its applicability to major sources has been delayed while it is reconsidered. For reference, the PM limit given in Subpart DDDDD is 0.0011 lb(f)/mmBtu.

The Department reviewed the initial and annual compliance tests conducted at the USS Bagasse Boiler No. 8 (controlled by an ESP) from 2005 to 2009 inclusive and found that the range of emissions was 0.004 to 0.015 lb(f) /mmBtu with an average of 0.0089 lb/mmBtu.

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).[24]

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.[25]

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 HEF 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;[26]
- The moisture content of the exhaust gas at the stack is in the range of 25-30%;
- The projected stack temperature at the HEF stack is 340 ^{o}F at 25% moisture;

[24] 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

[25] 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.

[26] 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;[27]
- 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; [28]
- 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.[29]

The Department concludes that any steam plume would form outside the stack if it 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} and VE. The Department will specify a filterable PM/PM_{10} limit of 0.015 lbmmBtu on the basis of an ESP. The Department's determination is equal to the BACT determination for the recently approved SRF sorghum to ethanol and steam project.

The Department has not yet finalized adoption of the SER threshold for $PM_{2.5}$ an SER.

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.

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 23.17 TPY from the project (18.26 TPY from the boiler) including 6.85 TPY of HCl (assuming 95% control). With the use of an ESP rather than a fabric filter baghouse, the HCl emissions can approach 10 TPY, which is the single HAP major source threshold. On the other hand, installation of Ox-cat will provide a margin of safety and it is likely that emissions of organic HAP will be less than the estimated value of 7.11 TPY from the boiler.

Because the PTE of HCl will be close to 10 TPY and the aggregate PTE of all HAP will be close to 25 TPY, it is necessary to establish enforceable HAP emission limits.

HCl Emissions

Although the applicant estimated 6.85 TPY, the Department will set a limit of 9.0 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). Compliance shall be demonstrated by an HCl-CEMS.

The 12-month limit equates to approximately 2.24 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.

Other HAP Emissions from the Boiler

The applicant estimates emissions of 1.05 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 7.29 and 3.03 TPY, respectively.

According to Table 5 in Section 3.5 above the applicant initially estimated Hg emissions of 0.025 TPY (50 lb/yr). According to the applicant, they made a very conservative (high) assumption and it is likely

[27] VE Test. Horton, Chuck. Record of Visual Determination of Opacity. USS Boiler No. 8. December 2, 2009.
[28] Telecom. Linero, A. and Tingleburg, K. Stack Plume Behavior for USS Boiler No. 8. August 31, 2010.
[29] Telecom. Linero, A., Heron, T. and Lewis, W. Stack Plume behavior for USS Boiler No. 8. September 7, 2010.

that annual emissions will be less than 20 lb/yr. There is no requirement to limit Hg from the project as long as it remains an area source of HAP and does not trigger the BACT SER of 200 lb/yr.

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 19.61 TPY. This limit is expressed as $\sum$ (HCl, HF, Cl_2, metal HAP, organic HAP) = 19.61 TPY. This limit will complement the individual enforceable limit of 9.0 TPY for HCl emissions.

The demonstration of compliance with 19.61 TPY limitation will be determined on a fiscal year basis, based on the initial and annual stack tests (organic HAP tested quarterly during first 24 months of HEF facility operation) conducted for the identified Cl_2, metal, HF and organic HAP stack tests coupled with the totalized HCl-CEMS data for the given fiscal year. The quarterly organic HAP test (if Ox-cat system removed, annual otherwise) will be averaged for each fiscal year. The HAP limit of 19.61 TPY from the boiler takes into consideration the applicant's separate estimate of 4.24 TPY of organic HAP from the ethanol process and 0.85 TPY of HAP as fugitive emissions and other HAP emissions from the boiler. Further details regarding the ethanol process are given further below.

The total HAP estimate for the facility is 24.7 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 will control acid gases and metal HAP;
- HCl emissions are limited to 9.0 TPY respectively by enforceable conditions and required CEMS;
- Good combustion practices will minimize formation of organic HAP;
- An Ox-cat system is required by the permit for the purpose of controlling CO and VOC and will reduce organic HAP including D/F;
- There will be an annual HAP cap of 19.61 TPY from the boiler based on the HCl-CEMS, and the required initial, quarterly and annual HF, 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:
- Chemical reagents will be incorporated into the fermentation scrubber to control HAP such as acetaldehyde.
- 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. Ammonia (NH_3) Slip

The applicant will comply with the NO_X limit given in the draft permit of 0.10 lb/mmBtu based on the installation of a hybrid suspension grate stoker boiler. There are no regulations that directly limit NH_3 emissions; however NH_3 can contribute to PM/PM_{10} and $PM_{2.5}$ emissions.

Low NH_3 emissions are easy to achieve when relying on SCR technology, but more difficult when relying on SNCR to achieve BACT-level NO_X emissions. The applicant for the previously permitted SRF project advised that FuelTech, a well-known supplier of SNCR systems, will guarantee NH_3 slip of 35 ppmvd for a grate stoker boiler. For the present project, HEF proposes a NH_3 limit of 30 ppmvd.

The Department will include the NH_3 slip requested by HEF and notes the following:

- Some of the NH_3 slip will tend to reduce HCl emissions because it will react with HCl to form ammonium chloride (NH_4Cl);

- Some of the NH_3 slip will tend to react with small amounts of SO_2, sulfur trioxide (SO_3) and SAM present in the exhaust to form ammoniated sulfates and sulfites; and
- Ammoniated chlorides and sulfates/sulfites will contribute to particulate matter (PM/PM_{10}) and visible emissions (opacity).

Installation of Ox-cat to control CO, VOC and organic HAP will allow HEF to tilt the GCP towards NO_X control. This will help make it possible for HEF to minimize NO_X without excessive use of NH_3 and thus also reduce the effects of NH_3 slip on PM/PM_{10} and opacity.

4.5. BACT Review for Cooling Towers (EU 003)

Discussion. Up to three cooling towers will be used for machine cooling, cooling the condensing set in the power block, and process cooling. The design parameters for the cooling towers are: one cell with a stack height of 35 feet, a combined circulating water flow rate of 34,000 gallons per minute (gpm), a temperature of 77 °F and a design drift rate of 0.001%.

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 0.37/0.19/0.19 TPY.

If not properly maintained and operated, heat exchangers in the ethanol process and machines may leak thereby contaminating the water of the associated cooling tower with VOC. The VOC will subsequently be stripped from the water stream by the air flow thus emitting the VOC to the atmosphere. HEF did not estimate VOC or organic HAP from the cooling tower 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, 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.

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 500 ppmw on an annual basis, the Department accepts the applicant's BACT proposal for the cooling towers.

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 machine cooling and process cooling towers. The applicant will be required to collect a sample of cooling water from each tower 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 cooling tower to the Compliance Authority 90 days before the HEF facility becomes operational.

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

Discussion. The ethanol production process will result in the emissions of ethanol (C_2H_5OH) 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. Properly designed scrubbers and thermal oxidizers (TO) can effectively control VOC and HAP emissions from ethanol production processes.

Wet scrubbers (water as solvent) can achieve good VOC reduction objectives when used on ethanol plants. Ethanol (C_2H_5OH), which comprises the bulk of the VOC emissions, is completely miscible in water. A properly designed scrubber could achieve a level of removal 99% or greater. Organic acids and strongly polarized molecules such as acetic acid (CH_3COOH) and methanol (CH_3OH – a HAP) can also be removed in a properly designed scrubber due to their strong interaction with water. A wet scrubber using water as a solvent can therefore be designed to accomplish excellent removal of VOC, especially from the distillation/dehydration steps.

Non-polar VOC such as ethyl acetate ($C_4H_8O_2$) and HAP such as acetaldehyde (C_2H_4O) and acrolein (C_3H_4O) are not as efficiently removed as C_2H_5OH when using a wet scrubber that uses only water as a solvent. Refer to Figure 21 from an equipment supplier presentation that suggests very good overall VOC removal efficiency (exceeding 99%) from a fermentation step scrubber (large carbon dioxide emitter), but poor performance for some of the miscellaneous VOC and HAP mentioned above.

Compound	Formula	Conc. Ppm	Inlet Lb/Hr	Removal Efficiency	Outlet Lb/hr
Water	H_2O	1,100	400	-	-
Carbon Dioxide	CO_2	970,000	8,300	-	-
Ethanol	C_2H_6O	2,200	2,000	99.8%	4.0
Methanol	CH_4O	16.0	1.0	99.7%	0.0
Formic acid	CH_2O_2	1.1	0.1	99.0%	0.0
Lactic acid	$C_3H_6O_3$	6.9	1.0	99.0%	0.0
Acetid acid	$C_2H_4O_2$	21.0	2.5	99.9%	0.0
Amyl alcohol	$C_5H_{12}O$	29.0	5.0	90.0%	0.5
Formaldehyde	CH_2O	3.4	0.2	99.9%	0.0
Acetone	C_3H_6O	0.4	0.1	35.9%	0.0
Acrolein	C_3H_4O	0.2	0.0	0.0%	0.0
Acetaldehyde	C_2H_4O	35.0	3.0	1.0%	3.0
Ethyl acetate	$C_4H_8O_2$	23.0	4.0	1.0%	4.0
Total TOC's			2,017	99.4%	11.5

Difficult to Remove with Water Solvent

Figure 21 – Typical Plant Performance Using Water as Solvent (source: Envitech. 2009)

According to Table 2-10 of the application, the HEF pre-control emission levels of the VOC ethyl acetate ($C_4H_8O_2$) and C_2H_4O (a HAP) are 568.2 and 144.3 TPY, respectively. Emissions of these two species would be very substantial if controlled by conventional wet scrubbers using water as the only solvent. Without additives in the water scrubber, the HEF project would emit more than 10 TPY of C_2H_4O even with 98% VOC control.

Reagents such as sodium bisulfite ($NaHSO_3$ - a food preservative) can be added to the scrubber water that will react with aldehydes to form an "adduct" that precipitates, thus allowing removal of at least the key HAP.

It is also possible to use other solvents, e.g. ethanol, as the scrubbing medium as well as inclusion of several stages to insure the required removal efficiency to meet the VOC reduction objective and to insure the source (when considering boiler and ethanol process emissions) does not emit 10 TPY of any HAP or 25 TPY of aggregate HAP.

While a TO can be used to treat emissions from the fermentation and distillation/dehydration scrubbers, these are typically used to control emissions from the drying of solid residue such as Dried Distillers Grains with Solubles (DDGS), which is a byproduct of the more traditional grain-to-ethanol production process.

Applicant's proposal. HEF proposes to use two wet scrubbers to control VOC and HAP emissions from the ethanol production process. One scrubber will be used to control VOC emissions from the fermentation system while the other scrubber will be used to control VOC emissions from the distillation/dehydration systems.

The exhaust gases from the fermentation scrubber will exit to the atmosphere through a stack which will have a design height of 25 feet (ft), a design diameter of 4.9 ft with a flow rate of 4,223 actual cubic feet per minute (acfm) and a temperature of 70 °F. The scrubbing liquor (water) will be fortified with $NaHSO_3$ to reduce C_2H_4O. The distillation/dehydration scrubber will use water for scrubbing and exit to the atmosphere through a vent with a flow rate of 120 acfm.

Each scrubber will be designed to achieve a minimum control efficiency of 98% control efficiency for VOC and HAP emissions. After control, VOC emissions are estimated at 76.41 TPY from the fermentation scrubber and 11.19 TPY from distillation/dehydration scrubber. Total HAP emissions from the two scrubbers combined are estimated to be 4.24 TPY.

According to the application, a TO would destroy 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 and GHG.

Department's Review. The Department believes that a TO can provide greater control than a wet scrubber. However, if a wet scrubber with additives is used to effectively control $C_4H_8O_2$ and C_2H_4O emissions, reducing VOC emissions by another 5-15 TPY and HAP emissions by several TPY, then utilizing a TO 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 and GHG.

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 fermentation scrubber stack shall not exceed 19.01 lb/hr (76.41 TPY); VOC emissions through the distillation/dehydration scrubber vent shall not exceed 2.78 lb/hr (11.19 TPY); and total combined organic HAP emissions through the wet scrubber stack and distillation/dehydration scrubber vent shall not exceed 1.05 lb/hr (4.24 TPY).

The Department notes that some of the traditional grain to ethanol projects have had difficulties in controlling VOC and HAP emissions.[30] The applicant will need to insure that the selected scrubber vendor has a full understanding and appreciation of the need to insure minimization of HAP emissions given the area HAP source determination made for this project. Also, the vendor will need to insure that the appropriate scrubber liquids or additives are used to remove $C_4H_8O_2$ (the key VOC other than ethanol) in order to comply with the VOC emission limit.

Initial and annual VOC stack tests on the ethanol process scrubbers will be required. Quarterly HAP tests will also be required except for those quarters when the Ox-cat system is available to control boiler CO/VOC emissions. 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.

4.7. BACT Review Storage Tanks (EU-005)

Discussion. The facility includes five volatile organic liquids (VOL) storage tanks subject to NSPS Subpart Kb: a fuel ethanol tank; a 200 proof ethanol tank; an off-specification ethanol tank; a denatured/gasoline product storage tank denaturant/gasoline tank; and ethanol process tanks. Tank capacities are typically 100,000 gallons. Ethanol and gasoline vapors will be the primary VOC emitted from these tanks.

[30] Air Quality and Ethanol Production – Nebraska's Experience, Nebraska Department of Environmental Quality, publication 07-004, September 2007.

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

- A tank to store anhydrous ammonia or urea for the SNCR system. 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 5,000 gallon tank to store ULSD fuel oil for emergency equipment.
- A tank to store sulfuric acid for use in the ethanol production process to adjust pH. 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.
- A 2,300 gallon tank to store methanol, xylene and ethylbenzene that will be used as a corrosion inhibitor at the HEF facility.

Applicant's proposal. The applicant proposes to design the tanks subject to NSPS Subpart Kb 40 CFR per 60.110b(a)(2) with internal floating roofs or the equivalent 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. In lieu of internal floating roofs in the Blending and Storage tanks, HEF may use pressure relief valves provided that these meet the equivalency requirements of NSPS, Subpart Kb.

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. If HEF decides to use pressure relief valves in lieu of internal floating roofs, it must provide to the Compliance Authority before construction of the Blending and Storage VOL tanks commences, proof of the valves equivalency as defined in the NSPS.

4.8. BACT Review for Truck Rack Product Loadout and Flare (EU-006)

Discussion. The denaturant ethanol product (ethanol blended with gasoline) will be loaded onto tanker trucks at a maximum rate of 600 gallons per minute using submerged fill. The maximum throughput product rate is 36,000,000 gal/yr of ethanol blended with 1.620,000 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; 5.64 TPY CO; 0.052 $PM/PM_{10}/PM_{2.5}$ and 7.0 TPY of VOC. Total HAP emissions from the flare and the loadout process were estimated by the applicant to be 0.22 TPY.

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 007)

Discussion. The materials stored in these silos include one limestone, hydrated lime or trona storage silo for the DSIS; one lime storage silo for the water treatment system; if used in SNCR system, one urea storage silo; and one fly ash storage silo. The silos will emit small amounts of $PM/PM_{10}/PM_{2.5}$ with the applicant estimating the total to be 0.85 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 Equipment (EU 008)

Discussion. One emergency generator rated at 2,000 kW will be installed to provide backup electrical power in the event of a power outage at the HEF facility. The engine will fire ULSD fuel oil or natural gas and will be limited to 500 hours per year of operation during emergencies. The 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 2006 or later.

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

Table 9 - 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.

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 natural gas 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 natural gas and to comply with the requirements of NSPS Subpart IIII. By complying with Subpart IIII, compliance is attained for Subpart ZZZZ.

Table 10 - 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.

4.11. BACT Review for VOC Fugitive Equipment Leaks (EU 009)

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 HEF 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 HEF facility also fall under EU-012:

- EU-003: Cooling Towers;
- EU-004: Ethanol Production Process;
- EU-005: Storage Tanks; and
- EU-006: 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 HEF facility becoming operational. The applicant estimates that VOC emissions from fugitive equipment leaks will 6.52 TPY. Total organic HAP emissions from the equipment leaks were estimated by the applicant to be 0.33 TPY.

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 HEF 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 list submitted to the Compliance Authority no later than 90 days before the HEF facility becomes operational. Finally, per Subpart VVa, HEF must demonstrate compliance with NSPS, Subpart VVA no later than 180 days after the initial startup of the HEF facility.

4.12. 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 HEF 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;
- A Flare to control emissions from product load out;
- 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, HEF 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 HEF 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 HEF 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 HEF commencing operation.

5. BIOMASS BOILER HEAT INPUT MONITORING

Monitoring of heat input is difficult when using biomass as fuel. Sugarcane and sweet sorghum bagasse can have high moisture contents (50%) and boiler energy will be expended to evaporate that moisture thus reducing the boiler efficiency.

To accurately calculate heat input, the Department will include in the permit a requirement to conduct a boiler thermal efficiency test in accordance with American Society of Mechanical Engineers (ASME) methods (refer to Appendix ASME of the draft permit). The boiler heat input rate calculations must then be performed using ASME methods or those provided in 40 CFR 75, Appendix F (refer to Appendix F of the draft permit.

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 SER: PM/PM_{10}, $PM_{2.5}$ (Federal SER only), 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 formally 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 HEF Advanced Biofuel Ethanol Biorefinery

The following tables list the largest existing stationary sources, by pollutant, in Highlands and nearby Counties. The maximum expected future emissions in TPY from the proposed project are also shown for comparison.

Table 11 - Largest Sources of SO_2 (2010) Nearest to the Proposed HEF Site (TPY)

Owner/Company Name	Site Name	County	Emissions
HEF (future)	**HEF (future)**	**Highlands**	**200**
Mosaic Fertilizer	Mosaic Fertilizer – South Pierce	Polk	7,899
Florida Power and Light (FP&L)	Manatee Power Plant	Manatee	7,491
FP&L	Martin Power Plant	Martin	5,295
Lakeland Electric	C.D. McIntosh, Jr. Power Plant	Polk	4,240
Mosaic Fertilizer	Mosaic Fertilizer – South Pierce	Polk	4,088
Indiantown Cogen	Indiantown Cogen Plant	Martin	2,040
Tampa Electric Company (TECO)	Polk Power Station	Polk	1,386
Mosaic Fertilizer	Mosaic Fertilizer – South Pierce	Polk	547
FP&L	Cape Canaveral Plant	Brevard	459
Waste Management	Okeechobee Landfill	Okeechobee	396
Waste Management	Gulf Coast Sanitary Landfill	Lee	369
Genon Florida	Indian River Power Plant	Brevard	351
TECO	Phillips Station	Highlands	530
Solid Waste Authority of Palm Beach County (SWAPBC)	SWAPBC	Palm Beach	140
Sugar Cane Growers Co-Op (SCGC)	SCGC	Palm Beach	213
New Hope Power	Okeelanta Cogeneration Plant	Palm Beach	202

Table 12 - Largest Sources of NO_X (2010) Nearest to the Proposed HEF Site (TPY)

Owner/Company Name	Site Name	County	Emissions
HEF	**HEF**	**Highlands**	**194**
FP&L	Martin Power Plant	Martin	4,034
FP&L	Manatee Power Plant	Manatee	2,161
Lakeland Electric	C.D. McIntosh, Jr. Power Plant	Polk	1,544
Indiantown Cogen	Indiantown Cogen Plant	Martin	1,533
SWAPBC	SWAPBC	Palm Beach	1,330
FP&L	Fort Myers Power Plant	Lee	1,263
U.S. Sugar Corp.	Clewiston Mill and Refinery	Hendry	887
New Hope Power	Okeelanta Cogeneration Plant	Palm Beach	800
Progress Energy	Hines Energy Complex	Polk	711
Lee County	Lee County Waste to Energy	Lee	702
FP&L	Cape Canaveral Plant	Brevard	612
SCGC	SCGC	Palm Beach	573
TECO	Polk Power Station	Polk	472
Osceola Farms	Osceola Farms	Palm Beach	460
TECO	Phillips Station	Highlands	442

Table 13 - Largest Sources of CO (2010) Nearest to the Proposed HEF Site (TPY)

Owner/Company Name	Site Name	County	Emission
HEF	**HEF**	**Highlands**	**560**
U.S. Sugar Corp	Clewiston Mill and Refinery	Hendry	14,919
Osceola Farms	Osceola Farms	Palm Beach	11,647
SCGC	SCGC	Palm Beach	11,563
New Hope Power	Okeelanta Cogeneration Plant	Palm Beach	1,947
FP&L	Martin Power Plant	Martin	1,446
Cutrale Citrus Juices USA	Cutrale Citrus	Polk	984
FP&L	Manatee Power Plant	Manatee	890
SWAPBC	SWAPBC	Palm Beach	655
Lakeland Electric	C.D. McIntosh, Jr. Power Plant	Polk	642
Progress Energy	Hines Energy Complex	Polk	446
Calpine	Osprey Energy Center	Polk	442
Southern Gardens Citrus	Southern Gardens Citrus	Hendry	401

Table 14 - Largest Sources of PM_{10} (2009) Nearest to the Proposed HEF Site (TPY)

Owner/Company Name	Site Name	County	Emission
HEF	**HEF**	**Highlands**	**31**
FP&L	Martin Power Plant	Martin	641
FP&L	Manatee Power Plant	Manatee	629
FP&L	West County Energy Center	Palm Beach	336
U.S. Sugar Corp	Clewiston Mill and Refinery	Hendry	309
SCGC	SCGC	Palm Beach	293
Osceola Farms	Osceola Farms	Palm Beach	285
FP&L	Fort Myers Power Plant	Lee	216
Lakeland Electric	CD McIntosh, Jr. Power Plant	Polk	195
Mosaic Fertilizer	Mosaic Fertilizer – South Pierce	Polk	113
FP&L	Cape Canaveral Plant	Brevard	43

Table 15 - Largest Sources of VOC (2010) Nearest to the Proposed HEF Site (TPY)

Owner/Company Name	Site Name	County	Emissions
Highlands EnviroFuels	**Highlands EnviroFuels (future)**	**Highlands**	**137**
US Sugar Corp	Clewiston Mill and Refinery	Hendry	2,001
Osceola Farms	Osceola Farms	Palm Beach	737
Cutrale Citrus Juices USA	Cutrale Citrus	Polk	561
Citrus World, Inc	Citrus World, Inc	Polk	516
SCGC	SCGC	Palm Beach	496
Tropicana Manufacturing Co.	Tropicana, Fort Pierce	St. Lucie	441
Citrosuco North America	Citrosuco North America	Polk	430
Southern Gardens Citrus	Southern Gardens Citrus	Hendry	279
Louis Dreyfus Citrus	Louis Dreyfus Citrus, Indiantown	Martin	258
Tropicana Manufacturing Co.	Tropicana, Bradenton	Manatee	250
Peace River Citrus Products	Peace River Citrus	De Soto	234
FP&L	Manatee Power Plant	Manatee	202
Genpak	Genpak	Highlands	197 (2009)

To further illustrate the major emission sources nearest to this proposed project, refer to Figure 22. All facilities within a 100 km radius of HEF that produce emissions of at least 100 TPY or greater in PM_{10}, SO_2, VOC, CO, or NO_X have been depicted. It should be noted that very few facilities with emissions greater than 100 TPY of a primary pollutant are located within a 50 km radius of the proposed HEF site.

There are regional efforts underway through the Federal Acid Rain Program and the CAIR to reduce emissions of NO_X and SO_2. Regional SO_2 emissions from existing power plants in the Southeast U.S. in 1995, 2007 and 2010 are listed in Table 16.

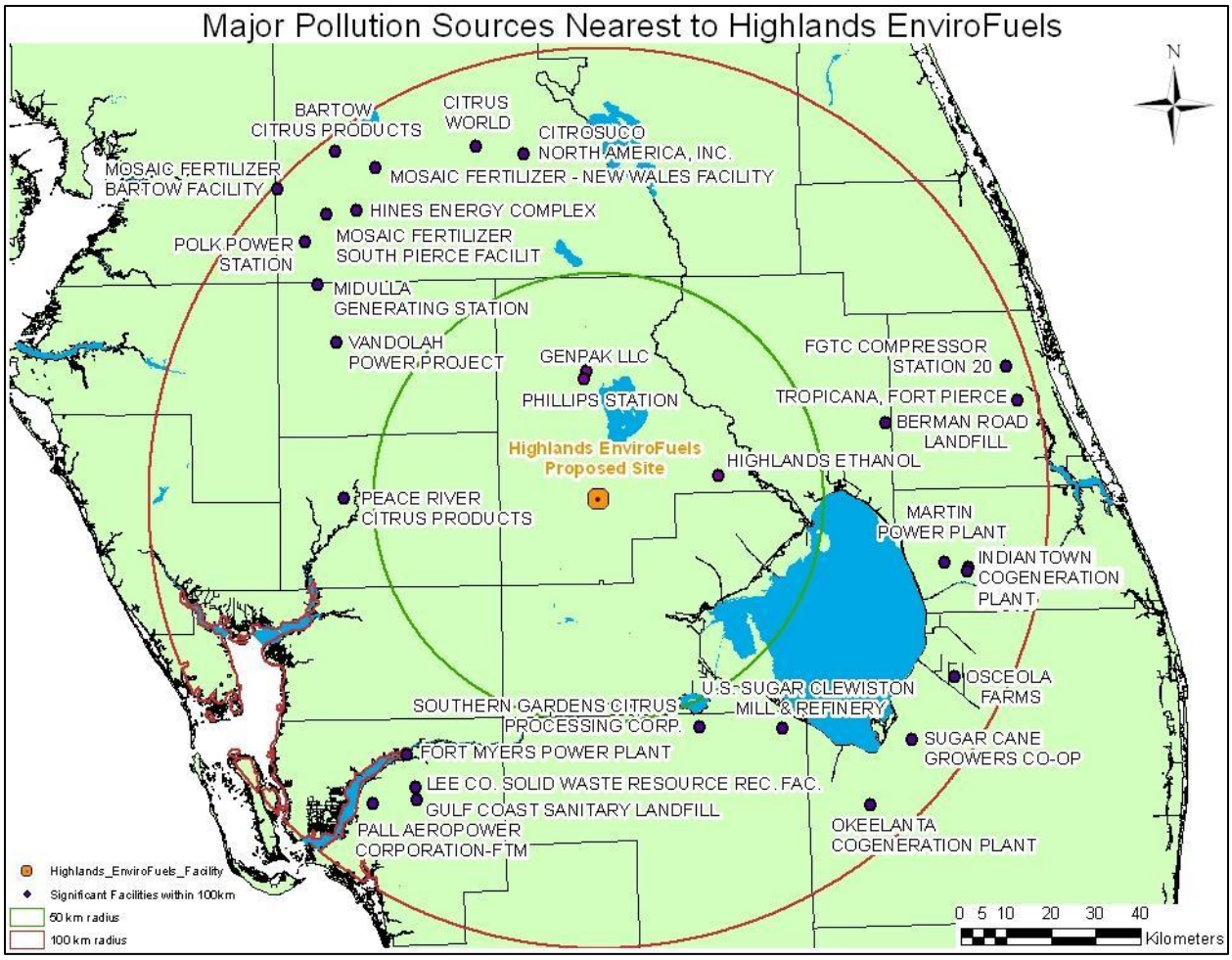


Figure 22 - Major Pollution Sources Nearest to Highlands EnviroFuels

Table 16. SO_2 Emission from Power Plants in the Southeast in 1995, 2007 and 2010 (TPY).

State	1995	2007	2010	Δ Since 1995 (%)	Δ Since 2007 (%)
Alabama	532,485	447,189	204,197	328,288 (62%)	242,992 (54%)
Florida	**598,262**	**317,582**	**144,552**	**453,710 (76%)**	**173,030 (54%)**
Georgia	478,904	635,484	218,911	259,993 (54%)	416,573 (66%)
Kentucky	676,263	379,837	271,514	404,749 (60%)	108,323 (29%)
Mississippi	83,869	69,796	54,696	29,173 (35%)	15,100 (22%)
North Carolina	385,737	370,826	120,387	265,350 (69%)	250,439 (68%)
South Carolina	177,855	172,726	94,656	83,199 (47%)	78,070 (45%)
Tennessee	493,472	237,231	118,723	374,749 (76%)	118,508 (50%)
Total	**3,426,847**	**2,630,671**	**1,227,636**	**2,199,211 (64%)**	**1,403,035 (53%)**

SO_2 emissions from power plants in the Southeast U.S. were reduced by nearly 2,200,000 TPY and 64% referenced to emissions in 1995. Over 1,200,000 TPY of those reductions occurred during the past three years alone. The state and regional SO_2 reduction trends will continue as coal fueled power plants continue to install scrubbers to control SO_2 emissions and in anticipation of additional regulations to control HAP and cross state pollution transport.

SO_2 emissions from power plants in Florida have declined by 453,710 TPY and 76% referenced to 1995. These reductions are the largest in the entire Southeast U.S. This is more than 2,200 times the future contribution of 200 TPY from the HEF project.

Regional NO_X emissions from existing power plants in the Southeast U.S. in 1995, 2007 and 2010 are listed in Table 17. NO_X emissions from power plants in the Southeast U.S. were reduced by nearly 1,300,000 TPY and 74% referenced to emissions in 1995. Almost 400,000 TPY of those reductions occurred during the past three years alone.

Table 17. NO_X Emission from Power Plants in the Southeast in 1995, 2007 and 2010 (TPY).

State	1995	2007	2010	Δ Since 1995 (%)	Δ Since 2007 (%)
Alabama	202,776	122,374	66,049	136,727 (67%)	56,325 (46%)
Florida	**297,056**	**184,171**	**79,493**	**217,263 (73%)**	**104,678 (57%)**
Georgia	169,999	107,471	60,588	109,411 (64%)	46,883 (44%)
Kentucky	365,532	174,840	91,979	273,553 (75%)	82,861 (47%)
Mississippi	47,243	48,546	29,774	17,469 (37%)	18,772 (39%)
North Carolina	258,469	59,417	57,305	201,164 (78%)	2,112 (4%)
South Carolina	93,480	46,062	28,833	64,647 (69%)	17,229 (37%)
Tennessee	309,237	102,886	35,056	274,181 (89%)	67,830 (66%)
Total	**1,743,792**	**845,767**	**449,077**	**1,294,415 (74%)**	**396,690 (47%)**

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 and in anticipation of additional regulations to control HAP and cross state pollution transport.

NO_X emissions from power plants in Florida were reduced by more than 217,000 TPY (73%) with half of the reduction occurring in the past three years alone. This is about 1,100 times the future contribution of 184 TPY from the HEF project.

6.3. SO_2 and NO_X Emission Trends from Power Plants in Florida

The Department graphed the SO_2 and NO_X emission trends during the period 1998-2010 from power plants in Florida that report their emissions to the EPA Clean Air Markets database. The results are summarized in Figure 23.

Per Tables 11 and 12 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 HEF site. To put emissions from the existing FP&L facilities and the future HEF 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 results are summarized in Figure 24.

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 HEF will emit 200 TPY of SO_2 and 184 TPY of NO_X.

The contribution of 200 TPY of SO_2 and 184 TPY of NO_X from the HEF 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.

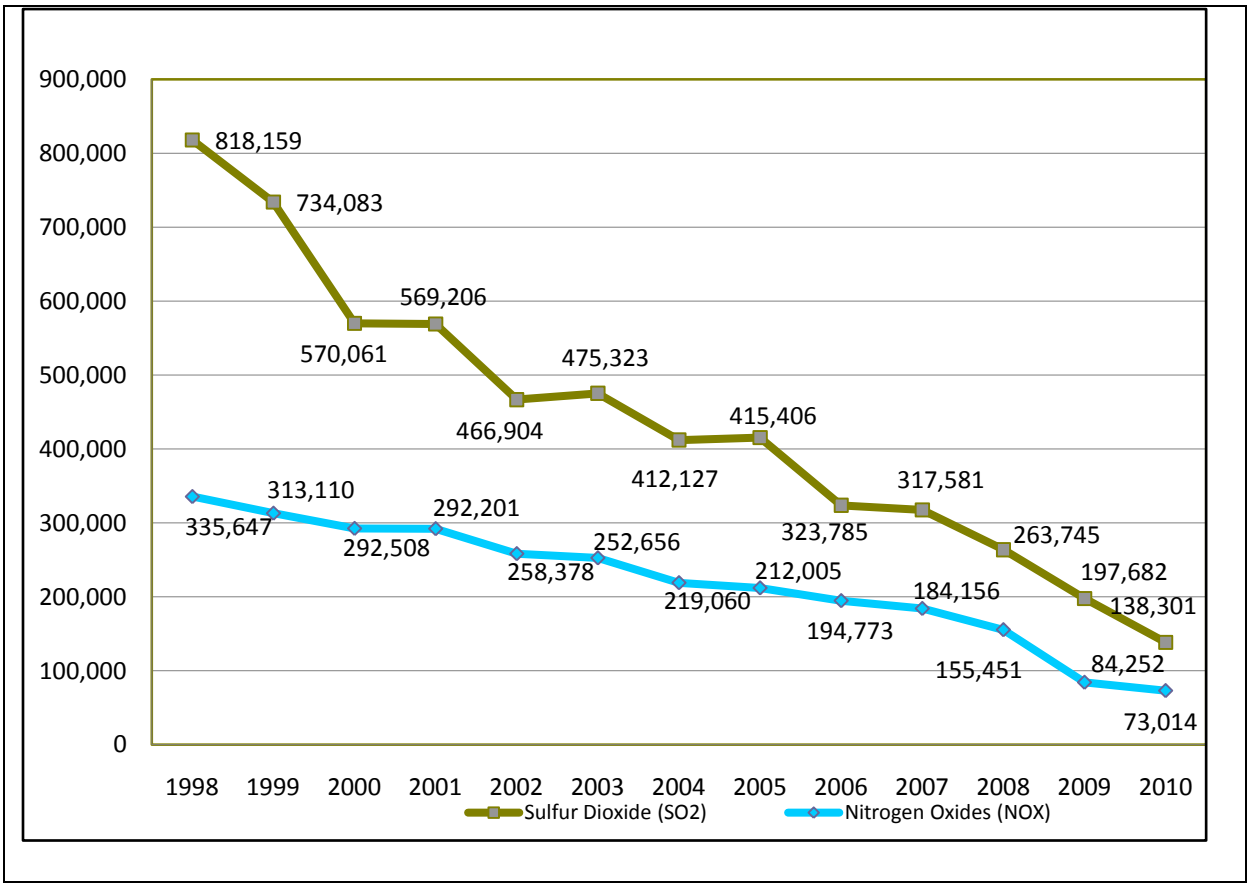


Figure 23 – SO_2 and NO_X reductions in TPY at Florida Power Plants (1998-2010)

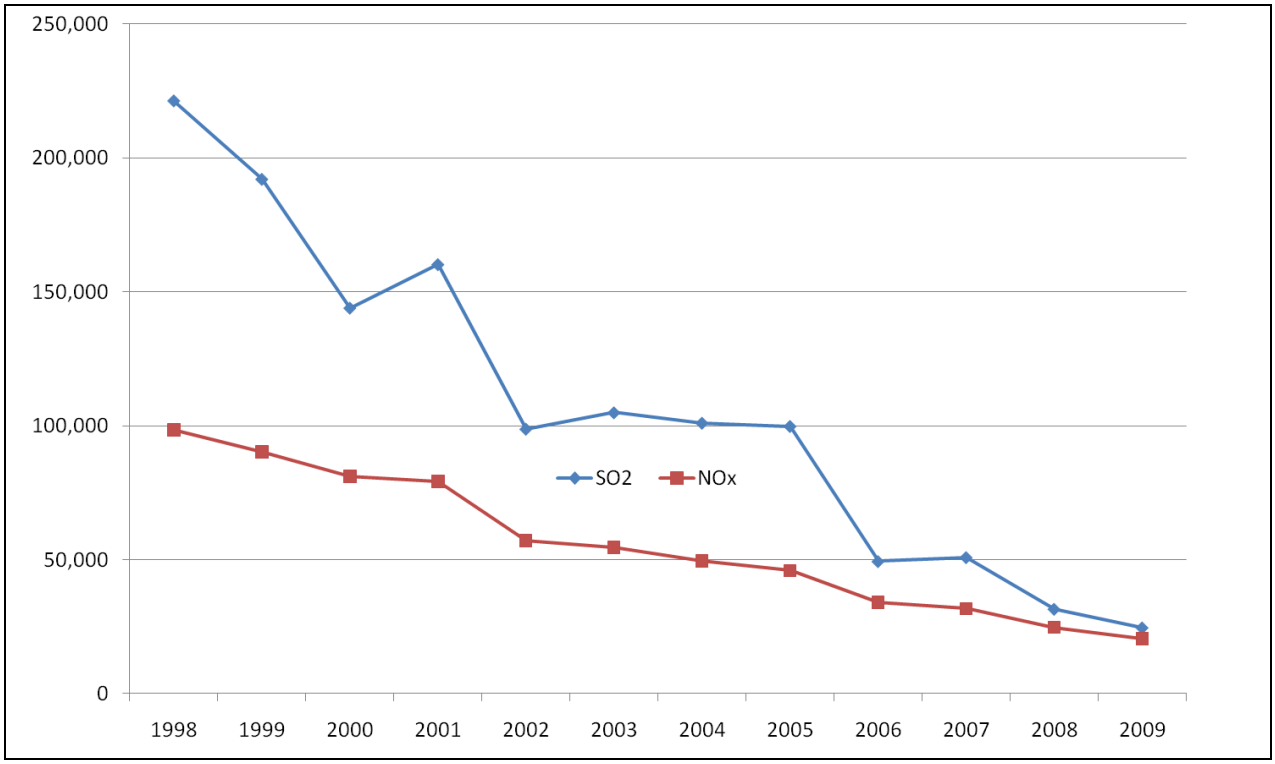
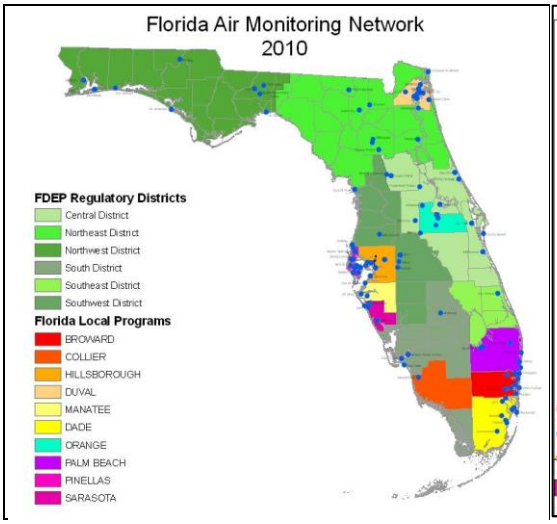


Figure 24 – SO_2 and NO_X reductions in TPY at FPL Peninsular Facilities (1998-2009)

6.4. 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 Figures 25 and 26 indicate, 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.



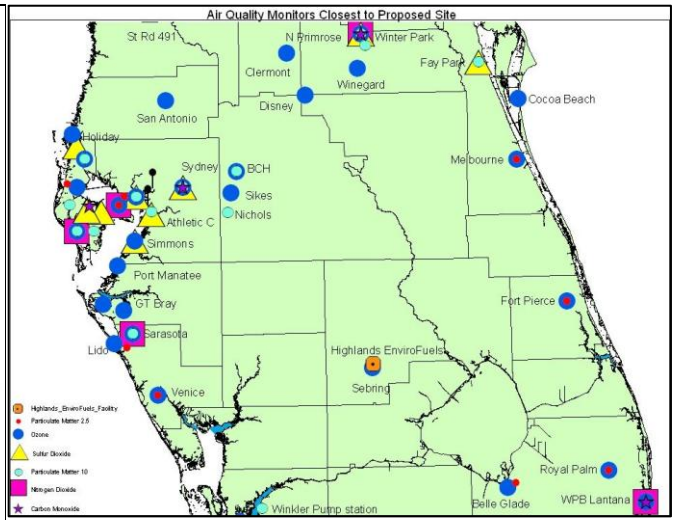


Figure 25 – Air Monitoring Network **Figure 26. Monitors Closest to proposed HEF site**

These monitors are used to estimate the existing air quality in the area of the proposed facility. The monitors in Belle Glade are most representative of the proposed site for PM_{10} and $PM_{2.5}$ due to their close proximity and rural setting. The Winter Park monitor is most representative of background SO_2 due to its similar rural setting, and was chosen over the Plant City station because the Plant City monitor is heavily influenced by CF Industries, a large SO_2 source. The NO_2 monitor located in Sarasota was also chosen due to its close proximity and similar rural setting, though it is still not quite as rural as the HEF site. Furthermore, the Sebring (Archbold) monitor was chosen to represent the background ozone concentration because it is located only 2 km from the proposed HEF site.

Air quality measurements from these monitors are summarized in Table 18. The ambient air measurements listed in the table are values that still contain 'exceptional events'. An 'exceptional event' is defined by EPA in accordance with 40CFR 50.14 as an event that affects air quality, is not reasonably controlled or preventable, is an event caused by human activity that is unlikely to recur at a particular location or natural event. Such events include complex wildfires, driven by prolonged drought conditions and other large-scale meteorological patterns. The department has evaluated several $PM_{2.5}$ episodes and found that they occur in conjunction with certain meteorological conditions, combined with very high SO_2 emissions and sulfate deposition.

The applicant had the option of excluding exceptional events from the dataset, but opted not to do so with the intention of erring on the conservative side. Therefore, for these reasons in combination with the fact that the above monitoring stations are generally located in slightly more urbanized areas than the proposed HEF project site, the background concentrations used in this modeling analysis are actually slightly higher than what is actually experienced at HEF site.

6.5. 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.

Table 18 - 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}	Sarasota (1151006)	24-hour [b]	2008	59	150	$\mu g/m^3$
		Annual [c]	2008	18.7	50	$\mu g/m^3$
$PM_{2.5}$	Belle Glade (0990008)	24-hour [d]	2008-2010	14	35	$\mu g/m^3$
		Annual [e]	2006-2008	6.2	15	$\mu g/m^3$
SO_2	Winter Park (0952002)	1-hour [i]	2010	9	75	ppb
		3-hour [f]	2008	13.1	1300	$\mu g/m^3$
		24-hour [f]	2010	5.2	260	$\mu g/m^3$
		Annual [c]	2007-2009	2.6	60	$\mu g/m^3$
NO_2	Sarasota (1511006)	Annual [c]	2010	4	53	ppb
		1-hour [h]	2008-2010	23	100	ppb
CO	WPB Lantana (0991004)	1-hour [f]	2007	1	35	ppm
		8-hour [g]	2009	0.9	9	ppm
Ozone	Sebring (0550003)	8-hour [g]	2009	0.066	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.
e. Three year average of the arithmetic annual means.
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

Ozone limits and measurements in Table 18 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 18 and Figure 27.

$PM_{2.5}$ (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 NH_3 naturally present in the air or added by other industrial sources.

$PM_{2.5}$ limits and measurements are summarized on three-year blocks, rolled annually. The reported 24-hour compliance value for $PM_{2.5}$ is 15 $\mu g/m^3$ as indicated in Table 18 for the Belle Glade site, and was calculated by taking the average 24-hour readings recorded each day during the three years (2008-2010). The value for each year that exceeds 98% of all daily measurements within each given year was identified and then the average of those three numbers was reported as the 24-hour compliance value and compared with the standard of 35 $\mu g/m^3$.

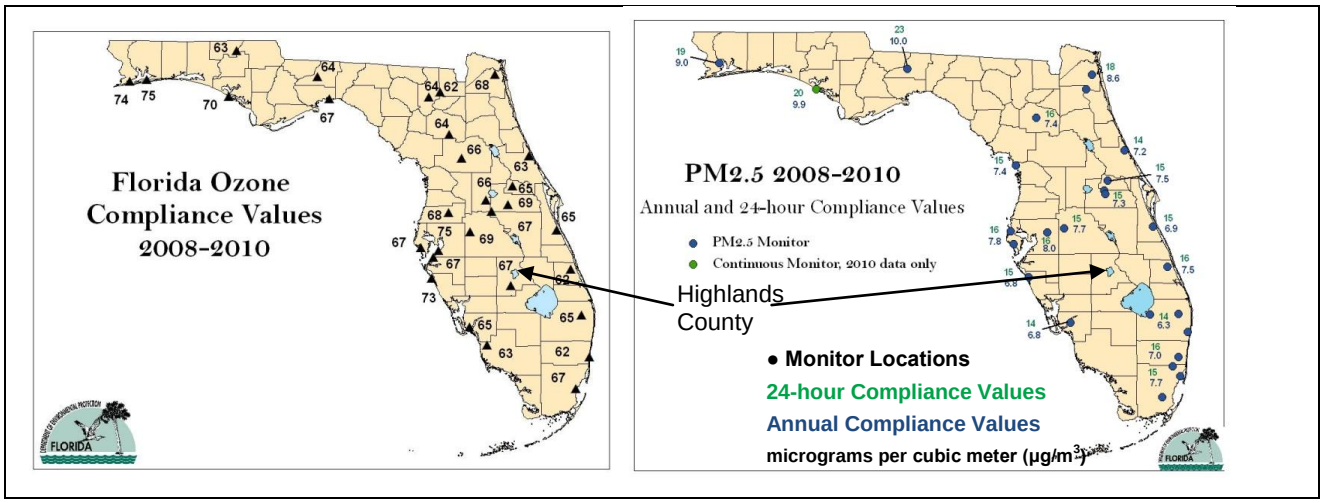


Figure 27 – Florida Ozone Compliance Values **Figure 28 – Florida $PM_{2.5}$ Compliance Values**

The simple average of all $PM_{2.5}$ measurements within each three years (2008-2010) 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 28 along with compliance values for the rest of the state.

The results indicate that Highlands County is in attainment with the applicable ozone and $PM_{2.5}$ AAQS. The results compiled from Highlands County (ozone) and Palm Beach County ($PM_{2.5}$) shown in Figures 27 and 28 support the conclusion that Highlands County is in attainment for both pollutants.

6.6. 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 29.

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. The harvesting associated with the HEF project will not be preceded by burning.

6.7. 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 AERMOD 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, but has provided an interim SIL equal to 4% of the NAAQS. The applicant agrees with this interim SIL and applied it for analysis of 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.];

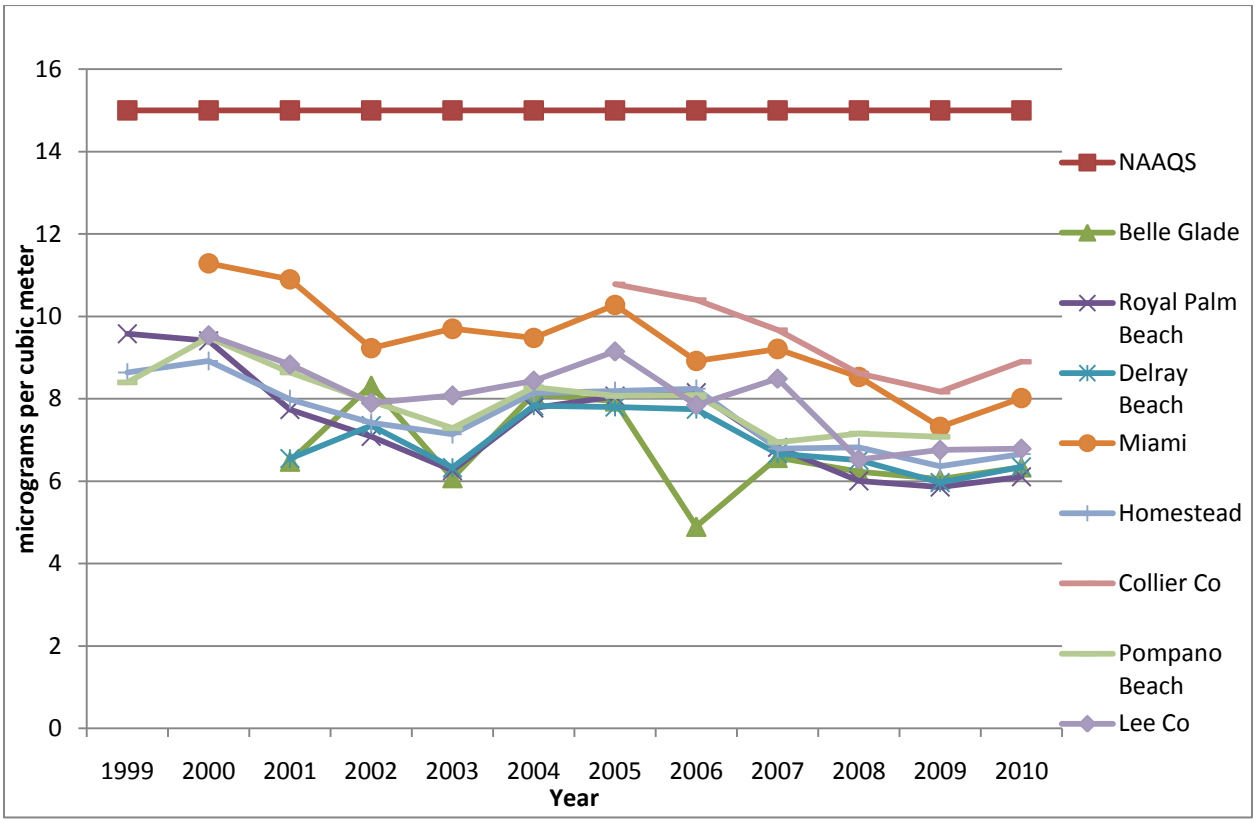


Figure 29 - South Florida Annual Average $PM_{2.5}$ Trends (1999 – 2010)

- The 4% SIL will capture all sources (regardless of size) within 2 km of HEF;
- The applicant also included all sources greater than 1,000 TPY beyond 10 km of HEF.

The applicant believes this approach encompasses all meaningful SO_2 and NO_X sources capable of interacting with HEF 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.

For the Class II analysis, a combination of fence line, near-field and far-field receptors were chosen for predicting maximum concentrations in the vicinity of the project. The fence line receptors consisted of discrete Cartesian receptors spaced at 50-meter intervals around the facility fence line. The remaining receptor grid consisted of densely spaced Cartesian receptors at 100 meters apart extending to 2 kilometers. From 2 to 7 kilometers, Cartesian receptors with a spacing of 250 meters were used from the facility. For addressing the 1-hour NO_2 NAAQS, the modeling grid was extended out to 15 km with additional receptors located every 500 meters, from 7 to 10 km, and every 1000 meters from 10 km to 15 km. The heights for all receptors were extracted using seamless National Elevation Data (NED) from USGS. For the Class I analysis, project impacts were predicted at 68 receptors located at 50 and 100 km in the direction of Everglades National Park (ENP).

The results of the applicant's significant impact analysis are shown below in Tables 19 and 20.

Table 19 - Maximum Predicted Air Quality Impacts from the HEF 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 24-Hour	1.5 11.2	1 5	50 150	Yes Yes	0.4 1.4
$PM_{2.5}$	Annual 24-Hour	0.43 5.2	0.3 [d] 1.2 [d]	15 35	Yes Yes	0.4 2.9
SO_2	Annual 24-Hour 3-hour 1-hour	0.58 8.1 23.7 29.7	1 5 25 7.9 [b]	60 260 1300 196	No Yes No Yes	- 0.9 - 4.8
NO_2 [c]	Annual 1-Hour	0.47 53	1 7.6 [b]	100 189	No Yes	- 12
CO	1-hour 8-hour	562.1 296.8	2,000 500	40,000 10,000	No 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 80% conversion of NO_X to NO_2, i.e., the tier 2 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 HEF Project for Comparison to the PSD Class I SIL for 2001 - 2005

Pollutant	Averaging Time	Max. Predicted Impact ($\mu g/m^3$)	Class I SIL ($\mu g/m^3$)	Significant Impact?
PM_{10}	Annual 24-hour	0.0019 0.10	0.2 0.3	No No
$PM_{2.5}$	Annual 24-hour	0.001 0.061	0.04 [a] 0.07 [a]	No No
NO_2 [b]	Annual	0.0064	0.1	No
SO_2	Annual 24-hour 3-hour	0.0091 0.25 (at 50 km), 0.13(at 100 km) 0.92	0.1 0.2 1	No No (at 100 km) No

a. Based on the lowest proposed concentration level from options in the proposed EPA rules for $PM_{2.5}$ SIL.
b. Assumes 80% conversion of NO_X to NO_2, i.e., the tier 2 modeling approach.

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 147 km from the project site, the maximum predicted impacts of due to the HEF project are all predicted to be less than the proposed PSD Class I significant impact levels for most pollutants and averaging periods at a 50km distance, except for the 24-hour SO_2 However, at a 100 km distance, the maximum impacts due to the HEF project are predicted to be less than the significant impact levels for all pollutants and averaging periods. Thus, no cumulative impact analyses were performed at Everglades National Park (ENP) since the project's impacts are expected to be well below the Class I SIL.

Preconstruction Ambient Monitoring Requirements

A preconstruction monitoring analysis is performed for those pollutants with listed significant monitoring concentrations (de minimis levels). These are levels, which, if exceeded, would potentially require pre-construction ambient monitoring. Refer to Table 21.

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

Pollutant	Averaging Time	Max Predicted Impact ($\mu g/m^3$)	De Minimis Level ($\mu g/m^3$)	Impact Greater Than De Minimis?
PM_{10}	24-hour	33.7	10	Yes
$PM_{2.5}$	24-hour	23.4	4	Yes
NO_2	Annual	0.6 [a]	14	No
SO_2	24-hour	8.1	13	No
CO	8-hour	297	575	No
Ozone	8-hour	124 [b]	100	Yes

a. Assumes 75% conversion of NO_X to NO_2, i.e., the tier 2 modeling approach (annual).
b. Values shown are VOC. There is no explicit de minimus concentration for ozone, but an increase in 100 TPY or more requires a monitoring analysis for ozone.

The maximum predicted impacts due to the proposed project are predicted to be below the PSD de minimis concentration levels for NO_2, SO_2 and CO, but above the de minimis concentration levels for ozone, PM_{10}, and $PM_{2.5}$. Because the predicted maximum 24-hour $PM_{2.5}$ and PM_{10} concentrations are greater than the de minimis levels, a pre-construction ambient monitoring analysis is required for both $PM_{2.5}$ and PM_{10} as part of the application.

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

The EPA-approved AERMOD modeling system was used to evaluate the pollutant emissions from the proposed project in the surrounding Class I & II Areas. 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 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 (reduced by 15%) and 1-hour (reduced by 20%) NO_2

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 85 km north-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. Because the area of the approximate 75-acre HEF site will be cleared and the trees will be removed, the surface roughness, shown based on existing land use, will be lower when the project is constructed and operated. As a result, the difference in land use values between the two sites, particularly for surface roughness, will be less and not expected to be a significant factor in evaluating impacts. 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?	Percentage of Increment Consumed
PM_{10}	24-hour	9.6	30	No	32%
	Annual	2.4	17	No	14%
SO_2	24-hour	27.9	91	No	31%
$PM_{2.5}$	24-hour	7.6	9	No	84%
	Annual	1.1	4	No	28%

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.

An evaluation of the NO_2 and SO_2 emission inventories for background sources considered in the PSD application for the HEF facility was performed to determine whether the method used to eliminate background sources from the 1-hour NO_2 and SO_2 NAAQS compliance modeling demonstration was reasonable. Background sources were included in the modeling demonstration if they were located within the significant impact area (SIA) of the project, or if they were located beyond the SIA but less than 50 kilometers (km) from the SIA and had potential 1-hour emissions of 1000 TPY or more.

In general, for the 1-hour averaging time, background sources are most likely to interact with a project if they are located near the project site, have source characteristics that are favorable to produce impacts under similar meteorological conditions as those for the project, and whose emissions (plume) can be realistically transported within 1 hour over distances to interact with other sources. As stated in EPA's memorandum of March 1, 2011, regarding modeling for the 1-hour NO_2 NAAQS, "the emphasis on determining which nearby sources to include in the modeling analysis should focus on the area within about 10 km of the project location in most cases. The routine inclusion of all sources within 50 km of the project location, the nominal distance for which AERMOD is applicable, is likely to produce an overly conservative result in most cases."

The locations of the NO_2 and SO_2 sources considered for the modeling analysis were presented in the application. For the 1-hour SO_2 and NO_2 concentrations, the project's SIA extended out to 4.75 and 12 km from the project location. The information also compares the emissions included in the modeling analysis within each distance range to the total emissions from all facilities located within that range.

Only one background source was located within 25 km from the project. Since it was located within the project's SIA, it was modeled. Beyond 25 km, there were only two sources with maximum 1-hour emissions greater than 1000 TPY. One source was located about 26 km and the other source located about 44 km from the project. Most of the other background sources had maximum 1-hour emissions of less than 25 lb/hr. Both of these sources were modeled. Based on this information, 100 percent of the SO_2 and 99 percent of the NO_2 emissions from all background sources located within 25 km and 45 km from the project were modeled.

To understand the meteorological conditions that produced the maximum 1-hour concentrations, modeling was performed for each year that produced the highest 5-year average of the 8th highest maximum daily 1-hour NO_2 concentration of 40.6 $\mu g/m^3$. Source contributions to that maximum value were also identified.

The proposed HEF project and a nearby facility, Lake Placid Asphalt Plant, were the only sources that contributed to the maximum 1-hour concentrations for each year. Background sources located more than 25 km from the project did not contribute. The maximum hourly concentrations were predicted to occur with wind speeds that ranged from 4.1 to 10.3 meters per second (m/s) during daytime hours, indicative of neutral and unstable stability conditions. With these wind speeds, the plumes from both sources can be transported to the receptor during the 1-hour period.

Maximum 1-hour NO_2 impacts were also predicted for a large emission source, Tampa Electric Phillips Station, located about 26 km from the project. Impacts were predicted at the same receptor that the maximum 1-hour concentrations were predicted from all sources. The maximum hourly concentrations were predicted to occur with wind speeds that ranged from 1.5 to 4.1 m/s during early morning hours,

indicative of stable stability conditions. With these wind speeds, the plume from this source is not likely to be transported to the receptor during a 1-hour time period.

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.

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	12.9	59	71.9	No	150
	Annual	2.4	18.7	21.1	No	50
$PM_{2.5}$	24-hour	4.5	14	18.5	No	35
	Annual	1.0	6.2	7.2	No	15
SO_2	1-hour	76.4	23.6	100	No	196
	24-hour	27.9	5.2	33.1	No	260
NO_2	1-hour	32.4	43.3	75.7	No	189

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 HEF 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 137 and 194 TPY respectively.

The ozone monitoring data at Sebring is only 2 km south of HEF and is sufficient for the purposes of background values at the HEF 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 that 194 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 HEF 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.

6.8. Additional Impacts Analysis

General Description with Regard to Growth and Air Quality Impacts

Highlands County experienced a 123-percent increase in population for the years 1978 through 2009. During this period, there was an increase in population of 55,013. Similarly, the number of households in the county increased since 1977 by 24,128, or 127 percent.

Growth-Related Impacts Due to the Proposed Project

According to the application, construction of the HEF facility will occur over approximately 12 to 18 months and will require an average of approximately 500 to 1,000 workers during that time. It is anticipated that many of these construction personnel will commute to the site. A total of about 60 additional permanent workers will be employed for the operation of the facility. Both the construction and permanent jobs are all new jobs created within Highlands County. However, the workforce needed to construct and operate the facility represents a small fraction of the population already present in the immediate area. Therefore, while there would be a small increase in vehicular traffic in the area, the effect on air quality levels would be minimal. There are also expected to be no air quality impacts due to associated commercial and industrial growth, given the location of the HEF site. The existing commercial and industrial infrastructure is adequate to provide any support services that facility might require and would not increase with the operation of the facility. The addition of the HEF project will have a small positive effect on the increase of growth in the area. However, the surrounding area will certainly remain agricultural in the future. The air quality data measured in the region of the HEF site indicates that the maximum air quality concentrations are well below the AAQS. Based on the trends presented of these maximum concentrations, the air quality has generally improved in the region since the PSD baseline date of August 7, 1977. As demonstrated above, the maximum air quality impacts resulting from the HEF facility are predicted to be low and for some pollutants and averaging times, below the significant impact levels. The cumulative 24-hour and annual average PM_{10}, 24-hour and annual $PM_{2.5}$, and 1-hour and 24-hour average SO_2, and 1-hour NO_2 impacts predicted demonstrate that the HEF facility and background sources will comply with the PSD increments and AAQS. As a result, the air quality concentrations in the region are expected to remain below the AAQS when the HEF facility becomes operational.

Impact on Soils, Vegetation, and Wildlife

The primary vegetation, as well as agricultural crop, in the vicinity of the HEF is orange trees in citrus groves. The site is surrounded by orange groves for a large distance in all directions. Exotic species will colonize portions of the area, most notably melaleuca (Melaleuca quinquenervia) and Brazilian pepper (Schinus terebinthifolius), particularly within drainage features associated with the agricultural operations. Soils in the area are primarily sandy soils. According to the modeling results presented in Section 6.0, the maximum air quality impacts due to the proposed HEF project are predicted to be below the AAQS and PSD increments. The AAQS were established to protect both public health and welfare. Public welfare is protected by the secondary AAQS, which Florida has adopted. Secondary standards set limits to protect public welfare, including protection against visibility impairment, damage to animals, crops, vegetation, and buildings. Since the project's impacts on the local air quality are predicted to be less than the AAQS and less than the effect levels on soils and vegetation, the project's impacts on soils, vegetation, and wildlife in the vicinity of the site are expected to be negligible.

The major air quality risk to wildlife in the U.S. is from continuous exposure to pollutants above the NAAQS. This occurs in non-attainment areas. Risks to wildlife also may occur for wildlife living in the vicinity of an emission source that experiences frequent upsets or episodic conditions resulting from malfunctioning equipment, unique meteorological conditions, or startup operations. Under these conditions, chronic effects (e.g., particulate contamination) and acute effects (e.g., injury to health) have been observed. Although air pollution impacts to wildlife have been reported in the literature, many of the incidents involved acute exposures to pollutants, usually caused by unusual or highly concentrated releases or unique weather conditions.

Compared to the AAQS, it is highly unlikely that emissions from HEF facility will cause adverse effects to wildlife due to the project's low impacts, which are predicted to be below the AAQS based on worst-case operation. Coupled with the mobility of wildlife, the potential for exposure of wildlife to the project's impacts is extremely unlikely.

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

An AQRV analysis was conducted to assess the potential risk to AQRV at the Everglades National Park (ENP), due to the proposed emissions from the HEF facility. Everglades National Park is the closest Class I area to the proposed project and is located 147 km to the south.

In October 2010, the Federal Land Managers (FLMs), consisting of the National Park Service, U.S. Forest Service, and U.S. Fish and Wildlife Service, issued the Federal Land Managers' Air Quality Related Values Work Group (FLAG), Phase I Report- Revised (2010). Based on the report, the FLMs recommended initial screening criteria that would exempt a source from AQRV impact review based on a source's annual emissions and distance from a Class I areas. The FLMs will consider a source located greater than 50 km from a Class I area to have negligible impacts with respect to Class I AQRVs if its total SO_2, NO_X, PM_{10}, and H_2SO_2 annual emissions (in TPY based on 24-hour maximum allowable emissions), divided by the distance (km) from the Class I area (Q/D) is 10 or less. The FLMs would not request any further Class I AQRV impact analyses from such sources.

From HEF emissions presented in Table 24, the maximum potential emissions are estimated to be as follows using the highest emission rate for the short-term period and assuming 8,760 hours/year operation:

With Q as 917.4 TPY and D as 147 km, Q/D (917.4 / 147) Q/D is equal to 6.2. This result is well below the FLM criteria of 10. As a result, an AQRV impact analyses is not required.

Table 24 – Maximum Potential Emissions for Short-Term Period

Pollutant	Averaging Period	Maximum Emission Rate (lb/hr)	
		Units	Value
SO_2	1-hour	lb/hr	70.6
PM_{10}	24-hour	lb/hr	8.94
NO_X	1-hour	lb/hr	126.76
H_2SO_4	24-hour	lb/hr	3.15
Total		lb/hr	209.4
		TPY	917.4

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.