TECHNICAL EVALUATION

&

PRELIMINARY DETERMINATION

APPLICANT

Highlands Ethanol, LLC
55 Cambridge Parkway, 8th Floor
Cambridge, Massachusetts 02142

Highlands Ethanol Facility
ARMS Facility ID No. 0550061

PROJECT

Draft Permit No. PSD-FL-406
Project No. 0550061-001-AC

Cellulosic Ethanol Production

COUNTY

Highlands County, Florida

PERMITTING AUTHORITY

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

February 4, 2010

1. GENERAL PROJECT INFORMATION

1.1. Facility Description and Location

The Highlands Ethanol Facility (HEF) will be a cellulosic ethanol production facility with a Standard Industrial Classification (SIC) Code No. 2869-Industrial Organic Chemicals Not Elsewhere Classified. The new facility will be located in Highlands County north of State Road (SR) 70, approximately 3 kilometers (km) east-northeast of Brighton, Florida. The UTM coordinates are Zone 17; 493.2 km East and 3,013.2 km North. The location of Highlands County is shown on the left side of Figure 1. The locations of Brighton and the HEF are shown on the Highlands County map below.

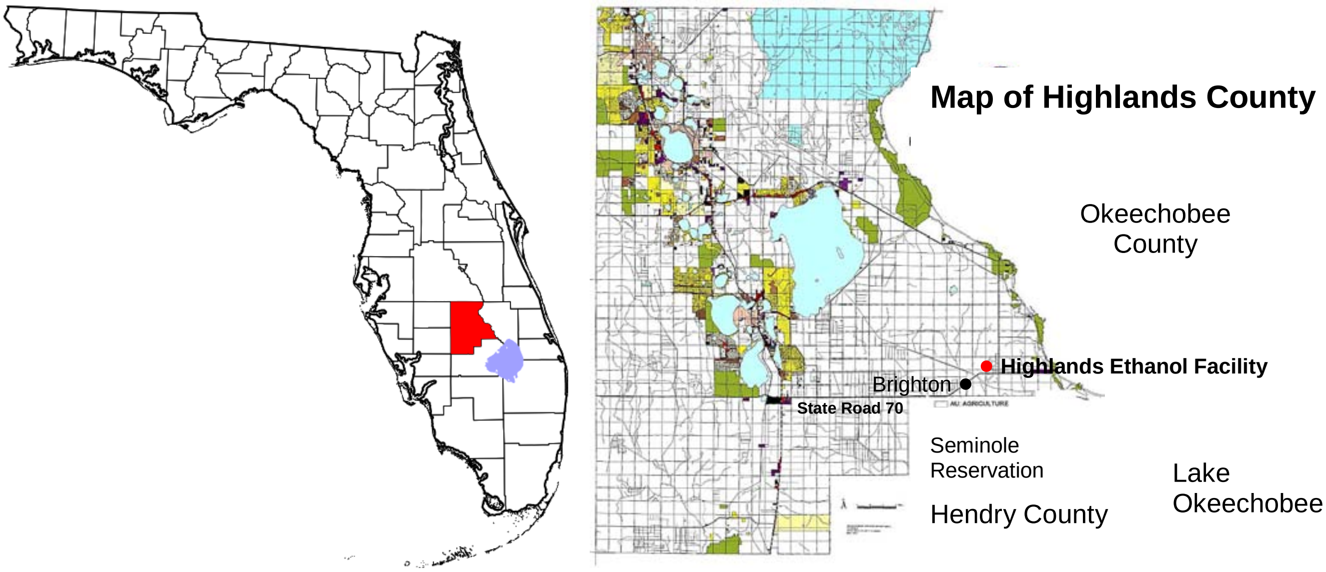

Figure 1 - Highlands County, Florida, Brighton in Highlands County, Proposed Location of HEF.

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 20 km to the southeast. Most of Highlands County is agricultural. Following are several photographs taken at the proposed site.

Figure 2 - Entrance to Proposed HEF Site, View of the Proposed Site, Adjacent Electric Substation.

Figure 3 - View to East and West along SR 70, Cowpen Operation South of the Proposed Site.

The proposed HEF will be located on property currently owned by Lykes Bros., Inc. The 95.7 acre site is surrounded entirely by Lykes Bros. property, with an easement allowing access to the site from State Route 70. The line between Highlands and Glades Counties is approximately 3 km south of the HEF site. The nearest point of the Brighton Seminole Reservation is approximately 8 km south of the site.

The nearest Prevention of Significant Deterioration (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 154 km south of the proposed HEF site.

1.2. Process description and the products made

The feedstocks for the facility will be dedicated energy crops, such as energy cane and forage sorghum, grown on adjacent farmland. The cellulose and hemicellulose in the crops will be converted to sugars that will be fermented to produce beer that will be distilled to produce fuel ethanol. The ethanol will be subsequently denatured with gasoline to produce the final ethanol product. Following is a very simplified diagram of the cellulosic ethanol production process excluding the denaturing step. It is also available at the website of Verenium (the parent company of Highlands Ethanol LLC) at the following link: www.verenium.com/cellulosic-ethanol_process.asp

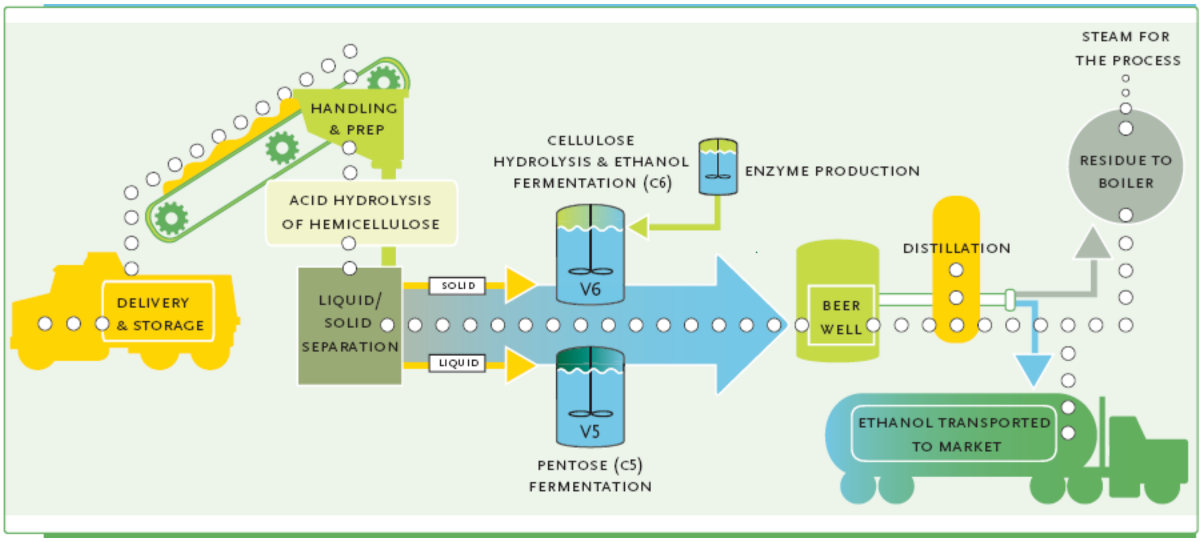

Figure 4 - Simplified Verenium Cellulosic Ethanol Production Process. (Verenium website)

1.3. Primary Regulatory Categories

- The facility is not a major source of hazardous air pollutants (HAP).
- The facility has no units subject to the acid rain provisions of the Clean Air Act.
- The facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.
- The facility is a major stationary source in accordance with Rule 62-212.400, F.A.C.

1.4. Project Description

Highlands Ethanol LLC submitted an application for an air construction permit subject to the preconstruction review requirements of the Prevention of Significant Deterioration (PSD) of Air Quality pursuant to Rule 62-212.400, F.A.C. The applicant proposes to build the first large commercial application of a cellulosic ethanol process. Verenium operates a 0.05 million gallons per year (MGPY) pilot plant in Jennings, Louisiana. A recently constructed 1.4 MGPY demonstration plant in Jennings will be operated to validate and optimize the Verenium process for final commercial scale up.

The feedstocks for the facility will be dedicated energy crops, such as energy cane and forage sorghum, grown on adjacent farmland. The HEF will have a permitted annual capacity 39.4 MGPY of ethanol that will be blended and denatured with gasoline to produce up to 41.5 MGPY of denatured product. The average daily ethanol production capacity is 108,000 gallons per day (gpd) and 118,800 gpd as peak daily capacity. The HEF will generate its own process steam fuel consisting of biomass (stillage cake) from the fermentation and distillation steps and biogas from the on-site wastewater treatment plant. Natural gas (NG-depending on local availability) and ultralow sulfur diesel (ULSD) fuel oil (FO) with a maximum sulfur (S) concentration of 0.0015% or propane will be used as backup fuels. The following table indicates new emissions units (EU) that will be added by this project. Details and a process diagram are provided further below.

Table 1 - Process Steps Comprising the HEF by EU.

EU ID No.	Emissions Unit Description
001	Feedstock delivery, handling and preparation
002	Hydrolysis, liquid/solids separation, neutralization
003	Fermentation, distillation and bacteria/enzyme propagation
004	Solids (stillage and gypsum) separation, dewatering and loadout
005	Denaturing and product storage
006	Product loadout and flare
007	Wastewater treatment system (WWTP), biogas conditioning and flare
008	Bubbling fluidized bed (BFB) combustion biomass-fueled boiler
009	BFB combustion biomass-fueled boiler
010	Backup fossil-fueled boiler primarily fueled by NG, propane or ULSD FO
011	Cooling tower
012	Miscellaneous storage silos
013	Miscellaneous storage tanks
014	Four emergency generators
015	Emergency fire pump engine
016	Facility-wide fugitive VOC equipment leaks

(001) Biomass Delivery and Handling

- Refer to the numbered process steps in the figure below. The facility will be designed to receive 3,600 green tons per day (TPD) of biomass feedstock (001a) for use in ethanol production. Freshly harvested energy cane and forage sorghum from adjacent farmland will be delivered by trucks equipped with a tipper for unloading material. The feedstock will be offloaded to a live bottom bin. The live bottom bin will transfer the feedstock to conveyers, through several washing steps and a screw press prior to the hydrolysis step.
- Prepared (sized and partially dried) supplemental boiler biomass fuel (001b) consisting of tree wood chips, bagasse or energy crop material will be delivered to the plant site in conventional tractor-trailer units or self-unloading trailers with live floors. The trailers will be unloaded to the ground using a hydraulic trailer dump platform and moved using mobile equipment to small storage piles. When required, the material will be reclaimed using a mobile wheel loader, and placed onto the live reclaim area from where it will be conveyed to a scalping screen or shaker screen and then transported to the boiler feed bin and fed into the biomass boilers to supplement stillage from the fermentation step.

(002) Hydrolysis of Hemicellulose, Liquid/Solid Separation and Neutralization

- Steam and a dilute acid solution hydrolyze (002a) the hemicellulose fraction of the biomass feedstock to produce slurry containing cellulose/lignin solids mixed with a liquid fraction containing a variety of pentose (5-carbon) sugars.

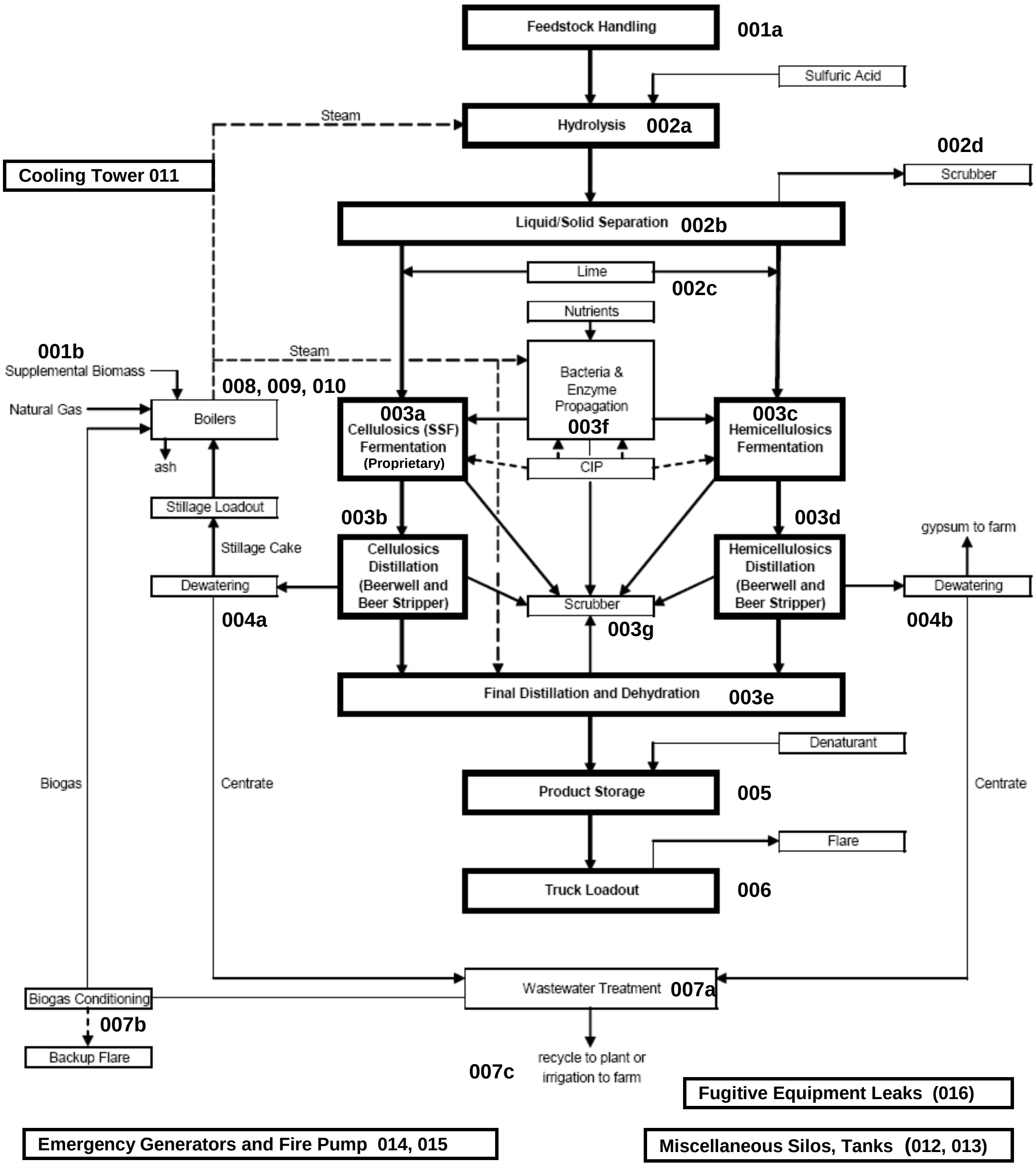

Figure 5 - Cellulosic Ethanol and E95 Production Process Diagram for HEF.

- The liquid pentose sugars are separated (002b) from the fiber solids through mechanical de-watering in a series of screw presses and sent to filtrate tanks to separate liquids and solids.
- The liquid pentose sugars will be neutralized with lime in a neutralization tank (002c). The cellulose/lignin solids stream will be neutralized with lime in a mixer. A vapor capture system will be used to collect the evaporative emissions from each of the enclosed feed tanks and filtrate tanks. The captured emissions will be exhausted to a wet scrubber (002d) dedicated to this step. Scrubbing water will be returned to the neutralization tank as make-up water. Each stream is then stored in a tank until a fermentation vessel becomes available.

(003) Enzymatic Conversion, Fermentation, Distillation and Bacteria/Enzyme Propagation

- The cellulose in the solids' stream will be converted to liquid glucose (six-carbon) sugars using a proprietary enzyme (003a). These sugars will be fermented with an enzyme to produce a dilute ethanol beer. The beer will then be transferred to a stripper that initiates the distillation process (003b).
- The hemicellulosic sugars will be separately fermented (003c) in batch mode with an enzyme to produce dilute ethanol beer. The fermented mash will be passed to a beerwell upon completion of each fermentation batch. The beer will then be transferred to a beer stripper that initiates the distillation process (003d).
- The heads (vapors) from the two beer strippers will be passed to a stripper/rectifier for further distillation (003e) and then a molecular sieve system to remove remaining water (dehydration) from the product.
- Proprietary bacteria and enzymes will be produced on-site (003f). These will be cultured, nourished and propagated under sanitary conditions using a clean-in-place (CIP) system. Nutrients required to produce the enzyme and bacteria will be stored adjacent to the propagation system.
- The vents associated with this equipment will be connected to a wet scrubber (003g) to control volatile organic compounds (VOC). Scrubbing water will be returned to the cellulosic beerwell as make-up water.

Equipment to be used for the fermentation, distillation, and propagation processes include four cellulosic fermentation tanks (003a), four hemicellulosic fermentation tanks (003c), two beerwells (003b and 003d), three cellulosic enzyme propagators (003f), three hemicellulosic enzyme propagators (003f), two beer strippers (003e), a stripper/rectifier (003e), and a molecular sieve system (003e).

The fermentation and propagation vessels will require a (CIP) system to provide sanitary conditions for the enzymes and bacteria. The CIP system will use a disinfectant solution such as caustic soda or sodium hypochlorite.

(004) Solids (stillage and gypsum) separation, dewatering and loadout

- The lignin-rich biomass residue (stillage cake) will be removed from the bottom of the cellulosic beer stripper, partially dewatered, and conveyed to the biomass boilers (004a). Stillage will be generated at a rate of 25 dry tons per hour with moisture content between 35 and 60%. Handling will be performed entirely within a closed system except for the conveyor.
- Gypsum ($CaSO_4$) residue will be removed (004b) from the hemicellulosic beer stripper, dewatered, and conveyed to farms.
- The water fraction from the stillage and gypsum dewatering steps will be conveyed to the wastewater treatment plant (WWTP).

(005) Ethanol, Gasoline Storage and Blending

The purified ethanol and gasoline (denaturant) will be stored in tanks and then blended, resulting in the denatured ethanol product, which will have dedicated storage tanks.

(006) Product Loadout and Flare

The denatured ethanol product will be loaded onto tank trucks at a rate of 600 gallons per minute. Vapors displaced from the trucks will be exhausted to a flare (006). The product loadout flare will have a rated capacity of 9.42 million Btu per hour (mmBtu/hr) to control vapors displaced from the trucks during the loading of denatured ethanol. The trucks are assumed as not in dedicated ethanol service (i.e., some trucks will have returned from delivering gasoline and gasoline vapors will be displaced).

(007) Wastewater Treatment Plant (WWTP), Biogas Conditioning and Flare

The facility will include a WWTP (007a) to treat process wastewaters and to condition the resulting biogas for use as fuel in the boilers or to flare it (007b) when it cannot be used in the boilers. The effluent from the WWTP will be recycled to the plant or reused for irrigation (007c). The flow through the WWTP will be approximately 1,640 gallons per minute (gpm). The WWTP and associated systems will consist of an equalization basin, clarifiers, anaerobic reactors, aeration basin and sand filters.

(008, 009, 010) Steam Production

Two BFB combustion boilers (008, 009), each with a design heat input capacity of 198 mmBtu/hr, will be used to combust the stillage cake augmented by supplementary biomass, NG and the biogas produced by the anaerobic reactors of the WWTP. ULSD FO or propane will be used at least until NG is locally available.

The facility will include a backup boiler (010) with a design heat input rate of 198 mmBtu/hr and the ability to burn biogas, NG, ULSD FO or propane. The ULSD FO storage tank will have a capacity of 110,000 gallons and will be contained in a concrete dike for spill containment.

(011) Cooling Tower

An induced draft evaporative cooling tower (011) will provide cooling of process water for the project. The tower will be of rectangular mechanical-draft design with six cells. Each cell will be equipped with its own fan and a high efficiency drift eliminator to minimize water drift losses. The recirculating flow rate will be approximately 22,500 gpm. Total dissolved solids in the cooling water are expected to be approximately 2,750 milligrams per liter (mg/l).

(012) Miscellaneous Storage Silos

The facility will include equipment and silos (012) for the handling and storage of dry materials. The materials stored in these silos include enzyme propagation nutrients and pebbled lime for the ethanol process and limestone, sand, urea and ash related to the biomass boilers. These materials will be stored in silos, each of which will be equipped with fabric filters to control emissions during material handling.

(013) Miscellaneous Storage Tanks

The facility will include several liquid chemical storage tanks (013) including fermentation nutrients and reaction chemicals. All of these tanks will be of a vertical fixed roof design except for an anhydrous ammonia (NH_3) storage tank, which will be of a horizontal pressurized design.

(014, 015) Emergency Generators and Fire Pump

- Four emergency generators (014), each rated at 2,000 kilowatts (kW), will be installed to provide backup electrical power in the event of a power outage at the facility.
- A backup 360 horsepower (hp) diesel fire pump (015) will also be installed to provide firewater during power outages.

Each of these emission units will fire ULSD FO or propane and will be limited to 500 hours per year of operation during emergencies and 100 hours for maintenance. Each unit will be operated no more than 100 hours per year for testing and maintenance purposes.

(016) Facility-wide Fugitive VOC Equipment Leaks

Fugitive VOC emissions (016) are grouped for the entire process and will be minimized by implementation of a monthly leak detection and repair (LDAR) monitoring program.

1.5. Processing Schedule

February 16, 2009: Department received the application for an air pollution construction permit;

March 16: Department requested additional information;

April 17: Department received additional information (partial response);

April 29:	Department requested additional information regarding truck traffic modeling;
May 22:	Department received additional information regarding biomass handling and storage;
July 21:	Department received additional information regarding truck traffic modeling;
September 17:	Department received additional information clarifying sulfur in fuel, providing a basic leak detection and repair (LDAR) plan, boiler heat input calculation methods and liquid fuel storage tank size;
October 23:	Department distributed Written Intent to Issue Air Permit and posted documents;
November 2	Highlands Ethanol LLC, filed first request for extension of time to file a petition;
January 29, 2010	Third and last extension of time to file a petition expired;
February 1, 2010	Settlement Stipulation signed by the Department and ADAGE; and
February 5	Department issued Revised Draft Permit package and posted documents.

2. APPLICABLE REGULATIONS

2.1. State Regulations

This project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Department of Environmental Protection 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.: 62-4 (Permitting Requirements); 62-204 (Ambient Air Quality Requirements, PSD Increments, and Federal Regulations Adopted by Reference); 62-210 (Permits Required, Public Notice, Reports, Stack Height Policy, Circumvention, Excess Emissions, and Forms); 62-212 (Preconstruction Review including PSD Review and Best Available Control Technology); 62-213 (Title V Air Operation Permits for Major Sources of Air Pollution); 62-296 (Emission Limiting Standards); and 62-297 (Test Methods and Procedures, Continuous Monitoring Specifications, and Alternate Sampling Procedures).

PSD applicability and the preconstruction review requirements of Rule 62-212.400, F.A.C. are discussed in Section 3 of this report. Additional details of the other state regulations are provided in Section 4 of this report.

2.2. Federal Regulations

The U.S. Environmental Protection Agency (EPA) establishes air quality regulations in Title 40 of the Code of Federal Regulations (CFR). Part 60 identifies New Source Performance Standards (NSPS) for a variety of industrial activities. Part 61 specifies National Emissions Standards for Hazardous Air Pollutant (NESHAP) based on specific pollutants. Part 63 specifies NESHAP provisions based on the Maximum Achievable Control Technology (MACT) for given source categories. Federal regulations are adopted in Rule 62-204.800, F.A.C. Additional details of the applicable federal regulations are provided in Section 4 of this report.

3. PSD APPLICABILITY REVIEW

3.1. General PSD Applicability

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 5 tons per year (TPY) of lead, 250 TPY or more of any PSD pollutant, or 100 TPY or more of any PSD pollutant and the facility belongs to one of the 28 listed PSD major facility categories.

PSD pollutants include: carbon monoxide (CO); nitrogen oxides (NO_X); sulfur dioxide (SO_2); particulate matter (PM); PM with a mean particle diameter of 10 and 2.5 microns or less (PM_{10} and $PM_{2.5}$); VOC;

lead (Pb); Fluorides (F); sulfuric acid mist (SAM); hydrogen sulfide (H_2S); total reduced sulfur (TRS), including H_2S; reduced sulfur compounds, including H_2S; municipal waste combustor organics measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans; municipal waste combustor

metals measured as particulate matter; municipal waste combustor acid gases measured as SO_2 and hydrogen chloride (HCl); municipal solid waste landfills emissions measured as nonmethane organic compounds (NMOC); and mercury (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, F.A.C. Emissions of PSD pollutants from the project exceeding these rates are considered "significant" and the Best Available Control Technology (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. 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.

In addition, applicants must provide an Air Quality Analysis that evaluates the predicted air quality impacts resulting from the project for each PSD pollutant.

3.2. PSD Applicability for the Project

The project is located in Highlands County, which is in an area that is currently in attainment with the state and federal AAQS or otherwise designated as unclassifiable. The facility is a chemical process plant, which is one of the 28 listed PSD major facility categories, and emits or has the potential to emit (PTE) 100 TPY or more of at least one PSD pollutant. Therefore, the facility is a major stationary source and the project is subject to a PSD applicability review.

Table 2 is a listing of the applicant's PSD-pollutant emission estimates. As shown in the table, the project is subject to PSD preconstruction review for emissions of: CO, NO_X, $PM/PM_{10}/PM_{2.5}$, SO_2 and VOC.

Table 3 is a list of PSD emissions by operation, i.e. process step. It is clear that the greatest emission source by far is steam production, which accounts for nearly 90% of all PSD-pollutants to be emitted from the HEF. Other meaningful pollutant emissions include: VOC from fermentation and distillation, fugitive VOC from leaks and fugitive particulate emissions from traffic and materials handling.

Table 2 - Summary of the Applicant's PSD Applicability Analysis.

Pollutant	Emissions Increase (TPY)	PSD SER (TPY)	Subject to PSD Review?
CO	192.0	100	Yes
NO_X	156.5	40	Yes
PM/PM_{10}	33.6	25/15	Yes
$PM_{2.5}$	24.7	10	Yes
SAM	< 7	7	No
SO_2	104.1	40	Yes
VOC	71.3	40	Yes
Hg	<< 0.1	0.1	No
Pb	0.1	0.6	No

Table 3 - Breakdown of Emissions by Process Step. (Largest sources are bolded)

Operation	CO	NO_X	PM/PM_{10}	$PM_{2.5}$	SO_2	VOC	HAP
Roadway Fugitives (001)			9.9	1.0			
Liquid/Solid Separation (002)						2.1	
Fermentation/Distillation (003)						18.8	6.4
Stillage Loadout (004)						2.8	
Product/Denaturant Storage (005)						1.7	0.1
Product Loadout (006)	2.3	0.4	0.02	0.02	0.004	5.3	0.4
Wastewater Treatment (007)	0.3	0.1	0.002	0.002	0.001	5.4	
Steam Production (008, 009, 010)	**173.4**	**130.1**	**17.3**	**17.3**	**104.1**	8.7	**9.6**
Cooling Tower (011)			0.7	0.7		4.1	0.2
Miscellaneous Storage Silos (012)			4.7	4.7			
Miscellaneous Storage Tanks (013)						0.0	
Four Emergency Generators (014)	15.6	25.2	0.8	0.8	0.02	2.8	0.1
Emergency Fire Pump Engine (015)	0.5	0.5	0.03	0.03	0.001	0.1	0.004
Fugitive Equipment Leaks (016)						**19.6**	1.0
Totals (small deviations due to rounding)	192.0	156.3	33.5	24.5	104.1	71.4	17.8

According to the application, the HEF will not be a major source of HAP because it will not emit 10 TPY or more of a single HAP or 25 TPY or more of all HAP. The main source of HAP is steam production and is primarily comprised of hydrogen chloride (HCl). The other meaningful HAP emission is acetaldehyde (C_2H_4O) from the fermentation and distillation step.

4. DEPARTMENT'S PROJECT REVIEW

4.1. Applicable State Regulations

There are no EU presently operating at the project site. The project will establish 16 new EU as described above. Following are some of the key state regulations and a statute that are applicable to the project:

- Rule 62-212.400 (PSD), F.A.C., which regulates the entire project;
- Rule 62-296.320, F.A.C. – General Pollutant Emission Limitation Standards;
- Rule 62-296.410, F.A.C. – Carbonaceous Fuel Burning Equipment;
- Rule 62-296.406, F.A.C. – Fossil Fuel Steam Generators with Less than 250 mmBtu Heat Input, New and Existing Units; and
- Section 403.061(18), Florida Statutes (F.S.), which states "the department has the power and the duty to encourage and conduct studies, investigations, and research relating to pollution and its causes, effects, prevention, abatement and control".

4.2. NSPS and NESHAP

For this project, the following NSPS (40 CFR 60) or NESHAP (40 CFR 63) provisions are applicable:

- NSPS Subpart A – General Provisions, which regulates all EU that are subject to a NSPS standard and, in particular, flare pilot flames (EU 006 and 007);
- NSPS Subpart Db – Industrial-Commercial-Institutional Steam Generating Units, which regulates the three boilers (EU 008, 009 and 010);
- NSPS Subpart IIII – Stationary Compression Ignition Internal Combustion Engines (ICE) (EU 014 and 015);
- NSPS Subpart Kb – Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 (regulates EU No. 005);
- NSPS Subpart VVa – Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry (SOCMI), which regulates EU 002 through 006 and EU 016; and
- NESHAP Subpart ZZZZ – Stationary Reciprocating Internal Combustion Engines (RICE) (EU 014).

For reference, certain otherwise applicable NESHAP including MACT requirements do not apply to the project because it is an area source (not a major source) of HAP. They are:

- NESHAP Subpart A – General Provisions (Excluded by reference in Subpart ZZZZ);
- NESHAP Subpart F – Organic HAP from the SOCMI;
- NESHAP Subpart G – Organic HAP from the SOCMI for Process Vents, Storage Vessels, Transfer Operations, and Wastewater;
- NESHAP Subpart H – Organic HAP for Equipment Leaks;
- NESHAP Subpart I – Organic HAP for Certain Processes Subject to the Negotiated Regulation for Equipment Leaks;
- NESHAP Subpart Q – Industrial Process Cooling Towers; and
- NESHAP Subpart DDDDD – Industrial, Commercial, and Institutional Boilers and Process Heaters (promulgated but vacated and now under re-evaluation by U.S. EPA).

4.3. Other Requests

By letter dated February 6, 2009, Highlands Ethanol requested that EPA provide an applicability determination for the following two NSPS:

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

By letter dated March 26, 2009, EPA provided a determination that the subject NSPS do not apply to the project because ethanol produced by biological processes is outside their respective scopes.

5. BACT REVIEW

BACT determinations are required for the pollutants that are subject to PSD review, including CO, NO_X, PM/PM_{10}/$PM_{2.5}$, SO_2 and VOC. These determinations are provided in the following sections and are organized and presented by process step.

In the case of $PM_{2.5}$, the Department relies on precursors and surrogates. The rationale is as follows:

On September 16, 1997, EPA revised the national ambient air quality standards (AAQS) for particulate matter, which includes a new AAQS 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 Clean Air Act, 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 State Implementation Plan to address the new $PM_{2.5}$, AAQS, PSD significant emissions rates and ambient air quality impact thresholds for modeling analyses as required by EPA for approved states by 2011. Until state regulations support PSD preconstruction review for $PM_{2.5}$ emissions, the Department will rely on PM_{10} emission limits and $PM_{2.5}$ precursor limits (e.g., SAM, SO_2, VOC, NH_3, and NO_X). This approach is more robust than the EPA guidance memoranda.

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

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

Discussion. PM/PM_{10}/$PM_{2.5}$ is the only pollution of concern from EU 001. The trucks that will be used to deliver ethanol process biomass and supplemental boiler fuel biomass will generate fugitive dust.

Upon receipt, the process feedstock will be offloaded to a live bottom bin as shown on the left hand side of the following diagram. The feedstock will be transferred from the live bottom bin to conveyors which will pass the feedstock through several washing steps prior to the hydrolysis process.

Figure 6 below is a diagram of the feedstock receiving and handling operation. Because of the feedstock's high moisture content and subsequent washing steps, fugitive emissions are expected to be minimal from this part of the process.

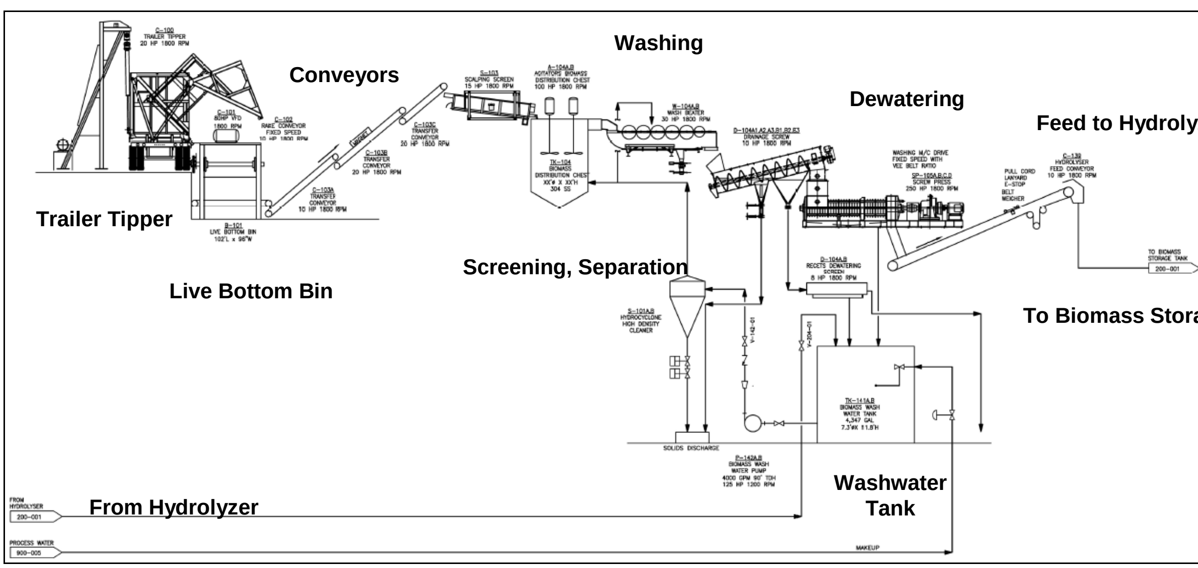

Figure 6 - Ethanol Process Biomass Feedstock Receiving and Handling.

Figure 7 is a diagram of the supplemental fuel receiving and handling operation. Prepared (sized and partially dried) supplemental boiler biomass fuel consisting of tree wood chips, bagasse or energy crop material will be delivered to the plant site in conventional tractor-trailer units or self-unloading trailers with live floors. The trailers will be unloaded to the ground using a hydraulic trailer dump platform and moved using mobile equipment to small storage piles.

When required, the material will be reclaimed using a mobile 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 boilers to supplement stillage from the fermentation step.

Applicant's Proposal. The only practical measures to control fugitive dust from roads is paving the roads or employing other dust control measures such as wetting and maintaining low vehicle speeds. Initially the applicant proposed to use unpaved roadways in the feedstock delivery area. The applicant now proposes to pave the feedstock loop road and all other roads at HEF. Deliveries of supplemental biomass fuel will also be made using paved roads.

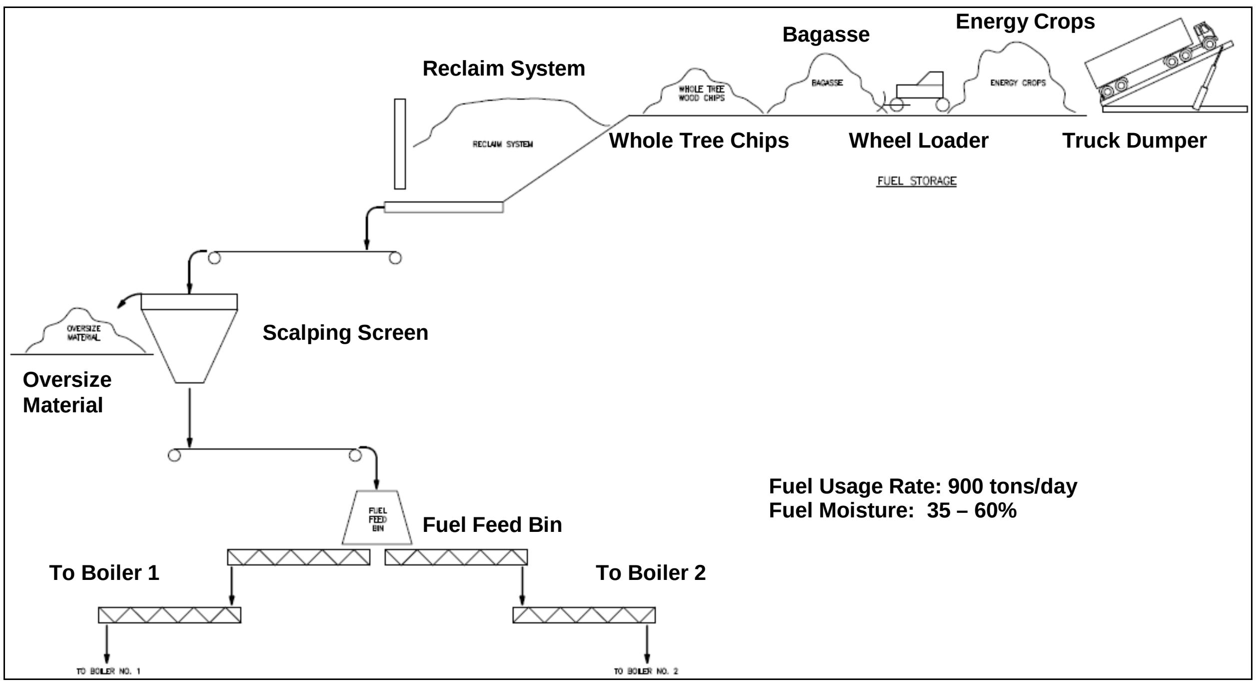

Figure 7 – Supplemental Fuel Receiving and Handling Operation.

As discussed above, the feedstock will be delivered and used on a just-in-time basis and any temporary storage will occur when the trucks are waiting to be unloaded. Supplemental fuel will be used to augment the stillage. The material is moist and will be managed in relatively small piles on gravel surfaces prior to reclaim.

Material transfer points will be enclosed to the extent practical. Conveyer belts will be covered to keep wind and rain away from the material. All conveying will be by mechanical means and no air (such as pneumatic systems) will be used in conveying, thereby reducing potential emission points.

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

5.2. BACT Review for Hydrolysis, Liquid/Solid Separation and Neutralization (EU 002)

Discussion. The stream entering liquid/solid separation (002b) from the hydrolyzer (002a) has trace levels of organics that are highly soluble in water such as acetic acid and furfural. However, some will evaporate in the process. Estimated emissions from liquid/solid separation after control are estimated at 0.6 lb/hr and 2.1 TPY of VOC.

Applicant's proposal. According to the applicant, wet scrubbing of the highly soluble emissions and thermal oxidation (TO) can provide equivalent levels of control. Highlands Ethanol is proposing to use a wet scrubber to control VOC emissions from the liquid/solid separation process. The applicant estimates control efficiency of 98% to yield the emission estimates given above.

Department's Review. The Department believes that TO can provide even greater control than a scrubber, but reducing emissions by another 1 to 2 TPY would not be cost-effective for this step in the process. Furthermore, the combustion of additional fossil fuels as required by a TO would result in additional emissions of criteria pollutants, including VOCs, and greenhouse gases. The Department accepts the applicant's proposal as BACT for this emissions unit.

5.3. BACT Review for Enzymatic Conversion, Fermentation, Distillation and Enzyme Propagation (EU 003)

Discussion. Ethanol will be the primary VOC emitted from fermentation/distillation and propogation. Other VOC such as acetic acid, lactic acid, and methanol (a HAP) will also be emitted. Emissions after control are estimated at 5.1 lb/hr and 18.8 TPY of VOC and 6.4 TPY of HAP.

Applicant's proposal. Highlands Ethanol proposes to connect the fermentation and distillation vents to a single wet scrubber. According to the applicant, cellulosic ethanol production differs from corn ethanol production in that fermenting organism propagation unit operations are more complex and there is an additional enzyme propagation unit operation. These unit operations require sparging of air into the process and also emit different volatile components than corn ethanol production. The applicant states "Highlands Ethanol has determined that 98 percent control is achievable by wet scrubbing. This is equivalent to the control level required for new facilities in Indiana and is as good as or better than all but three (nearly 90 percent) of the identified (traditional corn-based ethanol) facilities".

Department's Review. The Department believes that TO can provide greater control than a scrubber, but reducing emissions by another 5-15 TPY would not likely be cost-effective for this step in the process. Furthermore, the combustion of additional fossil fuels as required by a TO would result in additional emissions of criteria pollutants, including VOCs, and greenhouse gases. The Department accepts the procedures described by the applicant as BACT for this emissions unit.

This operation is the heart of the Verenium cellulosic ethanol process. Verenium is an affiliate of Highlands Ethanol and is the process developer. Verenium is conducting research at a pilot plant and a demonstration plant in Jennings, LA.

Based on their expertise and research regarding the differences between corn and cellulosic-based ethanol production, the Department agrees with their conclusion that a wet scrubber is appropriate as BACT for this project. The Department does not conclude here that a wet scrubber is BACT for grain ethanol projects.

The applicant shall also comply with 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 a wet scrubber, the Department notes that the applicant will have to comply with the Department's objectionable odor regulation and would have to apply for a permit to install additional control equipment or inject reagents to address objectionable odor problems.

5.4. BACT Review for Stillage Loadout (004)

Discussion. Stillage will be generated at a rate of 25 TPH and will consist primarily of lignin fibers and secondarily of unhydrolyzed cellulose fibers with a moisture content between 35 and 60 percent. Handling will be performed entirely within a closed system except for the conveyor. Based on the consistency and moisture content of the material, PM emissions are expected to be negligible. VOC emissions are estimated at 0.6 lb/hr and 2.8 TPY.

Applicant's proposal. According to the applicant, the VOC emissions occur from the evaporation of trace organics dissolved in the water fraction and maintenance of the material at ambient temperature will reduce the potential for fugitive VOC emissions.

According to the applicant, the only control options for this process would be to capture the emissions and vent them to a wet scrubber or TO. However, the potential uncontrolled VOC emissions from the process are calculated to be only 2.8 tons per year and their capture and control would not be cost-effective.

Department's Review. The Department concurs with the applicant's proposal to maintain the stillage cake at ambient temperature as BACT for this emissions unit. Corn-based ethanol plants typically have distiller's grain dryers that rely on energy recuperated from TO that also control VOC and odor. In the present case, use of the stillage in the biomass boiler will destroy much of the VOC and odor. The applicant shall comply with Rule 62-296.320(2), F.A.C. that prohibits objectionable odors.

5.5. BACT Review for Product and Denaturant (Gasoline) Storage Tanks (005)

Discussion. The facility includes two product shift tanks, two denatured ethanol storage tanks, one denaturant tank and one recycle product tank. Ethanol and gasoline vapors will be the primary VOC emitted from these tanks. Emissions after control are estimated at 0.5 lb/hr (1.7 TPY of VOC).

Applicant's proposal. The applicant proposes to design these tanks with internal floating roofs to minimize VOC emissions. The applicant also proposes to incorporate vapor balancing (also called Stage I control) to capture the displaced vapor from the gasoline storage tank and return it to gasoline tanker delivery trucks.

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/vacuum conservation vent, which allows the tanks to operate at a slight internal pressure and 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 floating roofs on the both the product tank and the denaturant tank and vapor balancing control on the denaturant tank as BACT for this emissions unit.

5.6. BACT Review for Product Loadout including Flare (006)

Discussion. Product will be loaded onto tank trucks at a rate of 600 gallons per minute using submerged fill. Vapors displaced from the trucks will be exhausted to a flare. Ethanol and gasoline vapors will be the primary VOC emitted from this operation. Emissions after control are estimated to be 9.3 TPY of VOC and 5.3 TPY of HAP.

Applicant's proposal. The applicant proposes to divert vapors displaced from the tanker trucks to a flare. The Product Loadout Flare will have a rated capacity of 9.4 MMBtu/hr and will provide 98% control efficiency for VOC emissions during the loading of E95 into 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.

5.7. BACT Review for WWTP, Biogas Conditioning and Flare (EU 007)

The facility will include a WWTP (007a) to treat process wastewaters and to condition the resulting biogas for use as fuel in the boilers or to flare it (007b) when it cannot be used in the boilers. The effluent from the WWTP will be recycled to the plant or reused for irrigation (007c). The flow through the WWTP will be approximately 1,640 gallons per minute (gpm). The WWTP and associated systems will consist of an equalization basin, clarifiers, anaerobic reactors, aeration basin and sand filters.

Discussion.

The WWTP will have aerobic (007a) and anaerobic (007b) sections. According to the applicant, the WWTP will emit 5.4 TPY of VOC and less than 1 TPY of any other pollutant as indicated in the following table.

Table 4 – Annual Emissions from WWTP including Flare (TPY)

Operation	CO	NO_X	PM/PM_{10}	$PM_{2.5}$	SO_2	VOC
Wastewater Treatment (007)	0.3	0.1	0.002	0.002	0.001	5.4

Most of the emissions will occur as VOC from the aerobic section. Methane (CH_4), VOC, hydrogen sulfide (H_2S) and NH_3 can be emitted from the anaerobic section. However, most of these gases can be recovered and used as biogas fuel in the biomass boilers and in the backup boiler.

Applicant's Proposal.

The applicant proposes as BACT to combust biogas from the anaerobic section in the biomass boilers and to install a flare for backup purposes. According to the applicant, combustion of the biogas in the boilers and use of a backup flare will provide a VOC control efficiency of 98%.

The applicant will also enclose the aerobic section equalization tank and primary clarifier to function much as a vertical fixed roof storage tanks. The VOC emissions from these tanks are thereby reduced significantly compared to tanks of open top design.

Department's Review.

The use of the biogas in the biomass boilers will provide BACT level treatment of all pollutants. The biogas will provide approximately 44 mmBtu/hr towards the 396 mmBtu/hr heat input required by the two biomass boilers combined. Combustion of the biogas in the boilers or in the flare will control odor from NH_3 and H_2S.

The backup flare will generally not operate and emissions should be relatively low. Use of the biogas in the biomass boilers and operation of the backup flare constitutes BACT for this project. The storage tank design of the equalization tank and primary clarifier is sufficient to minimize VOC emissions and no further control is necessary. The Department accepts the procedures and equipment described by the applicant as BACT for this emissions unit

5.8. BACT Review for Biomass-fueled Boilers (EU 008, 009)

NO_X Emissions

Discussion. The biomass fueled boilers are relatively small at 198 mmBtu/hr. If such boilers were used to efficiently produce electricity by burning fossil fuel, each would produce roughly 20 megawatts (MW) of electric power. The size is on par with medium size waste-to-energy or small sugar cane bagasse boilers. The characteristics of the two biomass-fueled boilers are provided in Table 5.

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. Each biomass boiler is expected to emit 65 TPY of NO_X.

Applicant's Proposal for NO_X. The applicant's BACT proposal is 0.075 lb/mmBtu on a 30-day rolling basis and is included in the top row of Table 6. The proposed NO_X control technology is SNCR whereby NO_X emissions are controlled by reaction with NH_3 or urea at high temperature in the furnace. Some of the projects listed in the table triggered PSD and others took synthetic minor limits to avoid triggering PSD or Non-Attainment New Source Review. All include use of biomass, wood chips or woody debris. Most projects, especially those imbedded within the RACT/BACT/LAER Clearinghouse (RBLC) survey, rely on SNCR.

Table 5 - Characteristics of each Biomass-fueled Boiler

Parameter	Description
Boiler Type	BFB design
Primary Solid Fuel Feed	Stillage and other biomass at maximum rate of 23.6 tons per hour (TPH)
Supplemental Fuel	NG assuming that the Florida Gas Transmission (FGT) expansion is completed in the area. Otherwise will fire ULSD FO or propane
Ash Removal	To ash storage silo and shipment off-site
Heat Input Rate	Nominal 198 mmBtu/hr (maximum 218 mmBtu/hr on a 4-hour basis)
Thermal Efficiency	To be established
Steam Production	100,000 – 130,000 lb/hour (to be determined based on efficiency)
Stack Parameters	6 feet diameter (maximum); 180 feet tall (minimum)
Flue Gas	78,905 actual cubic feet per minute (acfm) at 305 °F and 54,460 dry standard cubic feet per minute (dscfm)
Particulate Control	Fabric filter baghouse greater than 99% efficiency
NO_X Control	Selective non-catalytic reduction (SNCR) based on urea injection in the furnace
SO_2 Control	Dry limestone injection and clean stabilization and backup fuels
VOC and CO Control	Good combustion practices (GCP)

Selective catalytic reduction (SCR) and regenerative SCR (RSCR) involve the same reaction but in the presence of catalyst. The catalyst would be located in the dusty, medium temperature zone (prior to other control equipment) for the former or the clean, low temperature zone (after other controls) for the latter.

The applicant conducted a top/down BACT analysis for NO_X from the biomass boilers and concluded SCR is the top technology. However, the applicant claims:

"Dusty side SCR is not feasible with the fluidized bed combustion (FBC) boiler because of the high particulate matter loading prior to the fabric filter system. In this location, the catalyst is subject to damage from erosion, thermal sintering and fly ash deposition.

"Placement of an SCR system after other air pollution control equipment, termed cold side application, is the only feasible method of incorporating SCR into the FBC boiler system. Cold side applications require flue gas reheat (i.e., fossil fuel is burned to reheat the flue gas) to raise the gas temperature from approximately 270°F to 650°F, the optimum temperature range for effective NO_X reduction across the catalyst bed. Reheating the gas stream also involves heat recovery that adds capital and operating expenses. SCR systems also require reagent storage and management systems and a process control system that monitors reagent usage to minimize ammonia slip."

The applicant calculated the capital costs of SCR at more than $12,000,000 per boiler and the annualized costs at more than $3,000,000 per year per boiler. The cost effectiveness calculated by the applicant is $27,000 per ton of NO_X removed ($/ton). The applicant claims that SCR is not cost-effective.

By electronic communication dated September 17, the application added:

"Highlands Ethanol is proposing to primarily use process stillage solids, which is a new fuel for which there is no current commercial scale operating data available. From laboratory analyses, Highlands Ethanol knows that there can be considerable natural variability in this fuel due to natural variation in the energy crops such as that caused by plant age at harvest and weather conditions. Among the fuel characteristics that are affected by this variability is its nitrogen content, which generally averages from 2 to 3 times (up to 0.49% N) the content of whole tree wood chips.

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

Project Location	CO	VOC	NO_X	PM/PM_{10}	SO_2
HEF, Highlands County, FL BFB - stillage, wood, gas, ULSD FO ~198 mmBtu each (proposed)	**0.10** 30-day GCP	**0.005** stack test GCP	**0.075** 30-day SNCR	**0.01** Stack test fabric filter	**0.06** 30-day BFB limestone
ADAGE, Hamilton County, FL BFB – woody biomass ~760 mmBtu/hr (proposed)	~0.08 12-month GCP	~0.017 stack test GCP	~0.07 12-month SCR	~0.029 stack test fabric filter	~0.045 12-month lime in ducts
Wheelabrator, Auburndale, FL grate boiler – wood and tires ~630 mmBtu/hr (1990s)	0.32 30-day GCP	0.035 stack test GCP	0.14 30-day SNCR	0.02 stack test fabric filter	0.10 30-day lime spray
U.S. Sugar Clewiston, FL grate boiler - bagasse ~1,000 mmBtu/hr (2003)	0.38 12-month GCP	0.05 Stack test GCP	0.14 30-day SNCR	0.26 stack test fabric filter	0.06 30-day no control
RBLC Survey All designs – any biomass ≥ 100 mmBtu/hr	0.1 – 0.63 typical 30-day GCP	0.005 – 0.05 stack test GCP	0.075-0.45 30-day various	0.0125 – 0.8 stack test various	0.02-1.54 typical 30-day various
Whitefield Power & Light, NH whole tree chips (WTC) 15 MW	Not known	Not known	0.075 guarantee RSCR	Not known	Not known
Boralex Stratton, ME WTC 50 MW	Not known	Not known	0.075 guarantee RSCR	Not known	Not known
Bridgewater Power, NH WTC 16MW	Not known	Not known	0.075 guarantee RSCR	Not known	Not known
Burlington Electric, VT WTC 54 MW	Not known	Not known	0.065 guarantee RSCR	Not known	Not known
Palmer Springfield, MA construction/demolition (C&D) debris and WTC. 38 MW	Not known	Not known	0.065 guarantee RSCR	Not known	Not known
NSPS Subpart Db NG, wood, ULSD FO ≥ 100 < 250 mmBtu/hr	No standard	No standard	0.10-0.20 low/high heat release ULSD	0.03 20% opacity wood basis	0.20
NESHAP Subpart DDDDD[a] large solid fuel category ≥ 100 mmBtu/hr	~0.35 400 ppm @ 3% O_2[b] GCP	No standard	No standard	0.025 stack test	No standard

a. Subpart DDDDD was promulgated and then vacated

b. ppm @ 3% O_2 means parts per million by volume at 3 percent oxygen

"Further, variable amounts of nitrogen in Highlands Ethanol's boiler fuel may occur due to nutrient additions to propagate the fermentation organisms. Boiler vendor guarantees of 0.07 lb/mmBtu NO_X could be obtained for biomass fuels that are well known and tightly defined, such as those proposed for Adage. However, because of the higher nitrogen content of the biomass fuels to be used at Highlands Ethanol and the greater variability of the feedstock composition, the biomass fuel to be combusted at Highlands Ethanol does not have a specific fuel definition that would support a limit of 0.07 lb/mmBtu."

Department's Review. The selection of a BFB boiler (a type of fluidized bed boiler) is a primary NO_X control measure by itself. Following are some considerations (in quotes) by Babcock and Wilcox (B&W) when comparing the emission characteristics of a typical stoker furnace with a BFB boiler.

"The combustion zone temperature is typically neither measured nor controlled and can range from 2200 to over 3000 °F." This promotes the formation of thermal NO_X. "The BFB bed temperature is both measured and controlled to an optimum temperature of approximately 1500 °F." This minimizes thermal NO_X formation but not fuel NO_X formation.

"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. 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."

The Department considers the BFB feature as part of the BACT for the boiler. The Department does not concur that SCR is not feasible for further (add-on) control in the dusty medium temperature zone. While there are few SCR applications to-date for biomass projects, the Department notes that such an application for a BFB biomass project (ADAGE) that will incorporate SCR in the dusty medium temperature zone is presently under review by the Department as shown in Table 6.

The Department also disagrees that the cost effectiveness of SCR in the cleaner low temperature zone is as great as claimed by the applicant. The RSCR version of low temperature SCR is a relatively recent innovation wherein ceramic media are employed to heat the exhaust gases sufficiently to achieve a good reaction rate within the catalyst and then recover most of that heat in additional ceramic media after the catalyst. This reduces the heating costs and makes SCR more economical.

The vendor of the RSCR system (Babcock Power) claims a cost-effectiveness on the order of $4,000/ton NO_X removed for a single boiler producing 50 MW of electricity. When corrected for the smaller boilers at HEF, the figure will be somewhat greater. Most likely the cost-effectiveness is somewhere between the $4,000 figure and the $27,000 value estimated by the applicant. The cost-effectiveness will very likely be less than $10,000/ton NO_X removed.

The applicant proposes to achieve its proposed BACT NO_X limit by SNCR with performance that will almost match the guarantees listed for the RSCR system. In that case, the *marginal* cost-effectiveness of RSCR compared with SNCR may be substantial because the additional reduction in emissions of NO_X (on the order of 10-20 TPY per boiler) will be achieved at a relatively high additional capital cost.

The applicant will burn stillage (basically the remaining lignin from the process) rather than woody biomass. Stillage may contain more fuel nitrogen because the crops contain more nitrogen than woody biomass and because nutrients such as urea are introduced to cultivate enzymes and fermentation microorganisms. Thus it may form more fuel NO_X when combusted than typical woody biomass.

The Department notes that there is little information available about grain ethanol stillage (distiller's grain) combustion, let alone cellulosic ethanol stillage combustion. Most distiller's grain is used as animal feed or fertilizer. Combustion optimization of the cellulosic ethanol stillage is one subject of on-going research at the Verenium pilot and demonstration plants in Jennings, Louisiana.

Based on the foregoing discussion, the Department will set a limit of 0.075 lb NO_X/mmBtu on a 30-day rolling basis achievable by combustion in a BFB boiler incorporating SNCR or SCR. Compliance shall be demonstrated by a continuous emission monitoring system (CEMS).

SO_2 Emissions

Discussion. SO_2 is formed from S compounds contained in biomass. According to the application, each biomass boiler is expected to emit 52 TPY of SO_2. According to the application, stillage will comprise up to 12.5 TPH of the 23.6 TPH biomass feed to each BFB boiler. The application states:

"The boiler is designed to burn stillage cake from the distillation process as its primary fuel. The S content of the stillage cake will be a function of the raw materials that are input to the process (energy cane and forage sorghum) and the hydrolysis process which uses sulfuric acid."

Biomass entering the ethanol process (e.g. sorghum) at the HEF will be typically low in S content. A figure of 4.4% S (wet basis) was originally provided in the application (~21 lb/mmBtu) but subsequently corrected to a *maximum* content of 0.08% S (electronic communication dated September 17, 2009). The latter value is included in Table 7 along with heating value, ash and sulfur content of various types of biomass and fossil fuels. The values are on a dry basis except as otherwise noted.

Applicant's Proposal SO_2. The applicant's BACT proposal is 0.06 lb SO_2/mmBtu on a 30-day basis and is included in the top row of Table 6. Additional short term limits (not shown in the table) are 0.12 and 0.14 lb/mmBtu on 24-hour and 3-hour bases respectively. The proposed SO_2 control technology is limestone ($CaCO_3$) injection. The stated control efficiency per the application is 85 to 95%.

According to the applicant:

"The S content of the fuel may be variable and is not under the direct control of Highlands Ethanol. Therefore, use of low S fuel is not technically feasible. The only SO_2 emissions control methods that are technically feasible are combustion zone controls (limestone injection) and post-combustion controls (wet scrubber or spray dryer absorber).

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

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

"Spray dryer absorbers or wet scrubbers are typically understood to provide the highest level of SO_2 control possible in boiler applications. With the BFB design, however, limestone injection can provide SO_2 controls equivalent to that of spray dryer absorbers or wet scrubbers. Therefore, all three technologies are considered equivalent in this application and represent the top level of control.

"Highlands Ethanol proposes to utilize limestone injection to control SO_2 emissions from the biomass boilers, which represents the top level of control. Therefore, an analysis of economic, energy, and environmental impacts is not required."

Consequently, the applicant did not provide a cost analysis for further SO_2 reductions.

Department's Review.

In general, the Department disagrees that limestone injection alone is the top technology for SO_2 control. For example, Jacksonville Electric Authority employs limestone injection on two coal-fueled circulating fluidized bed (CFB) boilers (a type of FBC boiler) and incorporates polishing scrubbers in addition to limestone injection. Similarly, the Virginia City Hybrid Energy Center under construction in Wise County, VA will also combust coal and 20% biomass in a 585 MW CFB-based power plant. The Virginia project will incorporate limestone injection into the fluidized beds and lime injection/dry scrubbing of the exhaust gas to achieve a BACT SO_2 limit of 0.022 lb/mmBtu on a 30-day basis.

According to Table 6, the new grate boiler at U.S. Sugar in Clewiston fires primarily bagasse, supplemented with low S FO and complies with a SO_2 emission limit of 0.06 lb/mmBtu with no additional sulfur control. Some of the SO_2 is removed in the fly ash without the addition of sorbent. The U.S. Sugar bagasse boiler is about 5 times the size of the proposed HEF stillage boilers.

ADAGE proposes a non-BACT, PSD-avoidance limit of 0.045 lb/mmBtu on a 12-month rolling basis from a BFB-based power plant. The ADAGE woody biomass boiler will be about 4 times the size of the proposed stillage biomass boilers to be used at the HEF.

In contrast to ADAGE and U.S. Sugar projects, the stillage biomass to be combusted at the HEF is devoid of much of the cellulosic and hemicellulosic fractions because the latter materials are converted to ash-free and S-free ethanol. Consequently, the HEF stillage biomass contains a relatively greater fraction of the ash and S inherent in the source materials.

For the purpose of further evaluation, the Department will assume that the maximum 0.08% S content stated by the applicant is on a wet basis and that the fuel heat content stated in Table 7 is also on a wet basis. The pre-control SO_2 emission potential is calculated as follows:

(0.08 lb S/100 lb stillage)x(2 lb SO_2/lb S)x(lb stillage/4,200 Btu)x(10^6 Btu/mmBtu) = 0.38 lb SO_2/mmBtu.

Some SO_2 will be removed by interaction with the combustion product fly ash in a manner similar to that of U.S. Sugar. Furthermore, the applicant will supplement the stillage with a substantial amount of ULSD FO or NG or propane that contain practically 0% S. Additionally, the applicant will combust as-needed some biomass other than stillage that will be closer in characteristics to the ADAGE and U.S. Sugar fuel sources and lower in S than the HEF stillage.

Co-firing the stillage with varying amounts of clean fossil fuels and other biomass coupled with inherent removal characteristics of the stillage ash should control emissions to approximately 0.20 lb SO_2/mmBtu. Additional control by limestone injection to 0.06 lb/mmBtu (~70% further reduction) is a reasonable expectation goal on a 30-day basis.

To achieve 0.06 lb/mmBtu, the overall control strategy of supplemental combustion of clean fossil fuels, lower S biomass, the fuel ash absorption/adsorption and limestone injection must reduce pre-control emissions by approximately 85%.

The Department accepts the HEF BACT proposal and notes:

- The project is the first full scale commercial installation of a biologically-based cellulosic ethanol facility using the resultant biomass stillage as fuel;

- The stillage biomass boilers are relatively small and will each emit only 52 TPY each; and
- The determination is strictly for a stillage biomass boiler within a biologically-based ethanol project and is not a BACT determination for biomass boilers in general.

Based on the foregoing discussion, the Department will set a limit of 0.060 lb SO_2/mmBtu on a 30-day rolling basis achievable by combustion in a BFB boiler, supplemental firing of clean fossil fuels and incorporation of limestone injection. Compliance shall be demonstrated by an SO_2-CEMS.

CO and VOC Emissions

Discussion. VOC and CO are products of incomplete combustion. Refer to Table 6 above for a listing of CO and VOC limits from biomass projects.

Applicant's Proposal. The applicant's BACT proposals are 0.10 and 0.005 lb/mmBtu for CO and VOC respectively based on GCP. The proposed limit for CO is on a 30-day rolling basis. The applicant also proposes an 8-hour CO limit of 0.2 lb/mmBtu. According to the applicant, each biomass boiler is expected to emit 86.7 TPY of CO and 4.35 TPY VOC. Refer to Table 6 above for a listing of CO and VOC limits from biomass projects.

The proposed CO and VOC limits are equivalent to the lowest permitted CO and VOC emission rates identified for FBC biomass boilers.

Department's Review. Due to the intimate contact between the bed material and the fuel, improved fuel burnout occurs. This results in very low CO and VOC emissions. The Department agrees that the proposed values represent BACT for CO and VOC.

For reference, the recently vacated NESHAP Subpart DDDDD would have required compliance with a CO limit of 400 ppm @ 3% O_2 as a surrogate for organic HAP. This value is roughly equal to 0.35 lb CO/mmBtu.

The Department will set the CO BACT limit at 0.10 lb/mmBtu on a 30-day rolling average. Compliance shall be demonstrated by a CO-CEMS. The Department will set the VOC BACT limit at 0.005 lb/mmBtu. Compliance shall be demonstrated by initial and annual stack tests.

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

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

Applicant's Proposal. The applicant's BACT proposal is 0.01 lb/mmBtu for PM/PM_{10} based on fabric filter baghouses. According to the applicant, each biomass boiler is expected to emit 8.7 TPY of PM/PM_{10}. Refer to Table 6 above for a listing of PM/PM_{10} limits from biomass projects. Following is the main excerpt from the applicant's BACT analysis:

"*Technically feasible PM control technologies include fabric filters, electrostatic precipitators (ESP), cyclones and wet scrubbers. However, from a top-down perspective, the most effective types of PM control equipment being successfully applied to biomass boilers are fabric filters and ESP. Fabric filters have surpassed ESP as the preferred particulate control device because they provide better control for finer PM.*

"Highlands Ethanol intends to install fabric filters on the biomass boilers, which represents the top level of BACT control and no further analysis is required. The emission rates shown in Table E-12 (incorporated into Table 6 above) range from 0.0125 to 0.8 lb/mmBtu. Highlands Ethanol is proposing a PM/PM_{10} BACT emission limit of 0.01 lb/mmBtu (filterable, based on Method 5), which is more stringent than any of the units listed in the permit database."

Department's Review. Burnout in a BFB boiler is superior to that of a stoker furnace. This reduces the potential for fires in the pollution control equipment and allows for use of a baghouse to meet lower PM/PM_{10} limits and to minimize direct emissions of $PM_{2.5}$.

The Department will set the BACT PM/PM_{10} limit at 0.01 lb/mmBtu by fabric filtration. Compliance shall be demonstrated by initial and annual stack tests. A VE standard of 10% will also be established for the biomass boilers. The Department has reviewed $PM_{2.5}$ and believes that measures have been incorporated into the overall BACT for the project that will adequately address this pollutant. These measures include:

- BACT emission limits and controls for SO_2 and NO_X that tend to form $PM_{2.5}$ in the environment;
- The VE limit that directly controls the fraction of $PM_{2.5}$ that interferes with light transmission; and
- The Department will establish a NH_3 limit of 10 ppm to minimize direct NH_3 emissions that can form ammoniated compounds in the exhaust stream and in the environment.

The BACT determination for $PM_{2.5}$ is adherence to the BACT determinations for NO_X, SO_2, PM/PM_{10}, VE and the NH_3 slip limit.

5.9. BACT Review for Backup Fossil-fueled Boiler (EU 010)

Discussion. The backup boiler is also rated at 198 mmBtu/hr. It will be fueled by NG and biogas. ULSD FO or propane will be used at least until NG is locally available. The backup boiler will be used only when one of the biomass boilers is not available and is limited to 6,000 hours in any consecutive twelve month period with the allowed hours of operation reduced by 2 hours for every hour of fuel oil usage. Therefore, the emissions from the two higher-emitting stillage-fueled boilers represent the total PTE of all three boilers.

If the backup boiler is continuously fired with a combination of NG and ULSD FO (in lieu of a stillage-fueled boiler), its PTE will equal 6.2 TPY of $PM/PM_{10}/PM_{2.5}$, 62.4 TPY of NO_X, 31.8 TPY of CO, 4.8 TPY of SO_2 and 1.3 TPY of VOC. The main difference between NG and ULSD FO is that the PTE NO_X is 30.2 TPY for exclusive use of NG and 62.4 TPY for exclusive use of ULSD FO.

Applicant's Proposal. The applicant's proposals for all of the pollutants in lb/mmBtu from the backup boiler (and biomass boilers) are included in Table 8 with comparison limits from the RBLC survey and other standards.

SO_2 is controlled by specification of NG or other low sulfur fuels. The NG available in Florida generally contains less than 2 grains of S per 100 standard cubic feet (gr/100 SCF). The applicant is specifically proposing ULSD FO with S content equal to or less than 0.0015% (less than NG). These values equate to 0.0056 and 0.0017 lb SO_2/mmBtu for NG and ULSD FO firing, respectively. The characteristics of propane are assumed to be equal to those of NG for the purposes of this discussion.

Overall, the applicant proposes the values listed for the HEF project in the table as BACT and will accomplish these values by use of inherently clean NG and ULSD FO, flue gas recirculation (FGR), Low NO_X burners (LNB) and good combustion practices (GCP).

According to the applicant, *"there are 12 auxiliary boiler entries in the database that were listed in permit records as "auxiliary boilers." Two of these boilers have no controls. One of the boilers is controlled with SCR. The remaining examples are controlled with low NO_X burners, four in conjunction with FGR and three in conjunction with good combustion controls."*

"Proven add-on NO_X control technologies include SCR and SNCR. However, given the fact that the backup boiler will utilize clean fuels and only operate when the biomass boilers are not operational, add-on controls would not be cost effective. Therefore, the base level of control for the backup boiler, low NO_X burners with FGR, is determined to be BACT."

Table 8 - Emissions in lb/mmBtu – Boilers with Uses or Capacities Similar to Proposed Project

Project Location	CO	NO_X	VOC	PM/PM_{10}
HEF, Highlands County NG, propane, ULSD FO ~198 mmBtu/hr	0.035/0.037 (NG/ULSD FO)	0.035/0.072 (NG/ULSD FO)	0.0014/0.0015 (NG/ULSD FO)	0.0071 (ULSD FO) 0.0022 (NG)
Biomass Boilers ~198 mmBtu/hr, stillage[a]	0.10[a]	0.075[a]	0.005[a]	0.01[a]
Recent RBLC Survey	0.035 – 0.08	0.011 – 0.17	0.004 – 0.018	0.0022 – 0.0075
Port Westward, OR	0.08	0.05	0.005	0.002
Sithe Mystic, MA	0.08	0.035	0.008	0.007
Sithe Fore River, MA	0.08 and 100 ppm @ 3% O_2	0.035/0.10 (NG/FO)	0.008/0.004 (NG/FO)	0.08 (FO) 0.007 (NG)
FPL West County, FL 99.8 mmBtu/hr, NG	0.08	0.05	2 gr S/100 SCF NG, 10% opacity	
NSPS Subpart Db NG, ULSD $\geq$ 100 mmBtu/hr	No standard	0.20	No standard	
NSPS Subpart Dc NG, ULSD $\geq$ 10, < 100 mmBtu/hr	Record Keeping Required			
NESHAP Subpart DDDDD[b] large solid fuel category $\geq$ 100 mmBtu/hr	400 ppm @ 3% O_2	No standard		

a. The HEF biomass (stillage) boiler values are included for comparison with those of the backup boiler.

b. For comparison only - Subpart DDDDD was vacated and did not apply to area sources of HAP.

Department's Review. The Department agrees with the applicant's BACT analysis for CO, SO_2, $PM/PM_{10}/PM_{2.5}$ and VOC. The Department agrees that emissions from the backup boiler will be much less than emissions from the biomass boiler and that emissions from the biomass boiler will be avoided when the backup boiler is used.

Although the boiler is for backup use when a biomass boiler is not available, the applicant did not propose to limit the hours of use. The applicant did not conduct a cost-effectiveness evaluation to demonstrate that SCR or SNCR are not cost-effective based on continuous use.

The Department will reduce the allowed hours of operation by 1 hour for every hour that fuel oil is used. This will effectively limit the annual NO_X emissions to approximately 30 TPY or the same value as if the unit used NG exclusively. At a PTE of 30 TPY, add-on control equipment will clearly not be cost-effective.

The proposed controls of LNB and FGR to achieve 0.035 and 0.072 lb/mmBtu when burning natural gas and ULSD FO respectively and limited operation is determined to be BACT for NO_X.

5.10. BACT Review for Cooling Tower (EU 011)

Discussion. The 6-cell induced draft evaporative cooling tower will provide cooling of process water for the project. Cooling towers may emit particulate matter based on the loading in the recirculating water. They may also emit VOC as a result of heat exchanger leaks and their subsequent stripping from the water stream by the air flow. Estimated emissions after control are 0.7 TPY of PM/PM_{10}, 4.1 TPY of VOC and 0.2 TPY of HAP.

Applicant's proposal. The applicant proposes to install a drift eliminator with cooling tower drift limited to 0.0005 percent of the water recirculation rate.

According to the applicant, the most practical method of controlling VOC emissions is to promptly repair any leaking components. Highlands Ethanol proposes to collect a sample of cooling water on a weekly basis and analyze it for VOC. This will enable the early detection of leaking heat exchangers, thereby minimizing VOC emissions and odors.

Department's review. The Department concurs with the applicant's proposal for BACT.

5.11. BACT Review for Miscellaneous Storage Silos (EU 012)

Discussion. The materials stored in these silos include enzyme propagation nutrients and pebbled lime for the ethanol process and limestone, sand, urea and ash related to the biomass boilers. The silos will emit small amounts of $PM/PM_{10}/PM_{2.5}$ estimated at 4.7 TPY total.

Applicant's proposal. The applicant proposes to control $PM/PM_{10}/PM_{2.5}$ emissions from the miscellaneous dry materials storage silos by fabric filter dust collectors achieving a concentration of 0.0005 grains per dry standard cubic foot (gr/dscf).

Department's review. The Department concurs with the applicant's proposal for BACT.

5.12. BACT Review for Miscellaneous Storage Tanks (EU 013)

Discussion. The materials stored in these tanks include aqueous solutions of corn steep, lactose and glucose. According to the applicant, pollutant emissions are minimal to the point of being negligible.

Applicant's proposal. The applicant proposes to install vertical fixed roof design on these tanks that will achieve minimal emissions for the described liquids.

Department's review. The Department concurs with the applicant's proposal for BACT.

5.13. BACT Review for Emergency Generators (EU 014)

Discussion.

Four emergency generators (014), each rated at 2,000 kilowatts (kW), will be installed to provide backup electrical power in the event of a power outage at the facility. They will be used sparingly and limited to 500 hr/yr of operation and 100 hr/yr for testing and maintenance. According to Table 3 above, the emissions from each engine will range from 0.005 TPY of SO_2 to 6.3 TPY of NO_X.

The emergency generators are ICE and RICE. They shall comply with applicable provisions of NSPS Subpart IIII and NESHAP Subpart ZZZZ. Pursuant to 40 CFR 63.6590(c) the engines meet the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII.

Applicant's Proposal.

The applicant proposes to use ULSD FO or propane 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.)
BACT Proposal	3.5	0.64	5.76	0.20	0.0015%
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.

5.14. BACT Review for Emergency Fire Pump Engine (EU 015)

Discussion.

The single 360-horsepower (hp) fire pump engine required for the project will be used sparingly and limited to 500 hr/yr of operation and 100 hr/yr for testing and maintenance. According to Table 3 above, emissions of each PSD-pollutant will be between 0.03 and 0.5 TPY.

This emergency fire pump is an ICE and a RICE. They shall comply with applicable provisions of NSPS Subpart IIII and NESHAP Subpart ZZZZ. Pursuant to 40 CFR 63.6590(c) the engines meet the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII.

Applicant's Proposal.

The applicant proposes to use ULSD FO or propane 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.)
BACT proposal	0.3	2.7	0.15	2.6	0.0015%
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.

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 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.

5.15. BACT Review for VOC Fugitive Equipment Leaks (EU 016)

Discussion. Uncontrolled fugitive equipment leaks 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. Estimated emissions after control are 19.6 TPY of VOC and 1 TPY of HAP.

Applicant's Proposal. It is not feasible to collect such leaks and treat them using the control devices (such as scrubbers and flares) installed in the individual units. The project 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.

According to the applicant, 18 facilities have established such LDAR programs at ethanol production facilities. The applicant proposes development of a LDAR program and compliance with the requirements of Subpart VVa as BACT for this project.

The applicant provided the following LDAR program developed pursuant to Subpart VV (the predecessor of Subpart VVa) for the smaller Verenium pilot and demonstration projects in Jennings, LA. The applicant proposes to rely upon the requirements of Subpart VVa and will provide a more comprehensive version for the larger commercial project at the HEF no later than 90 days before the HEF becomes operational.

Leak Detection and Repair (LDAR) Program

1. PURPOSE

   The objective of this procedure is to establish guidelines for implementing and managing a Leak Detection and Repair (LDAR) program at the HEF located in Jennings, Louisiana. The use of this procedure will assure compliance with federal and state regulations.

2. SCOPE

   This procedure applies to all regulated components used in Volatile Organic Compound (VOC) service at the Verenium Biofuels Louisiana Ethanol Facility.

3. REFERENCES
   a. 40 CFR Part 60 Subpart VV (would be Subpart VVa for HEF)
   b. LAC 33: III. 2121 (would include the analogous Florida Rule 62-204.800, F.A.C)

2. PROJECT TASK
   a. Task 1 - Identification of Components
      - Identify each regulated component on a site plot plan or on a continuously updated equipment log.
      - Assign a unique identification (ID) number to each regulated component.
      - Purchase tags and physically locate each regulated component in the facility, verify its location on the piping and instrumentation diagrams (P&IDs) or process flow diagrams, and tag each component. Update the equipment log if necessary.
      - Record each regulated component and its unique ID number in a log.
      - Promptly note in the equipment log when new and replacement pieces of equipment are added and equipment is taken out of service.

   b. Task 2 - Leak Definition
      - Identify the leak definition for each regulated component. Leak definitions vary by regulation, component type, service (e.g., light liquid, heavy liquid, gas/vapor), and monitoring interval. Many equipment leak regulations also define a leak based on visual inspections and observations (such as fluids dripping, spraying, misting, or clouding from or around components), sound (such as hissing), and smell.

   c. Task 3 - Monitoring Components
      - Identify the monitoring intervals for each regulated component. Monitoring intervals vary according to the applicable regulation but are typically weekly, monthly, quarterly, or annually.

- Monitor all regulated components in accordance with EPA Method 21 (40 CFR Part 60 Appendix A) at the intervals specified by the regulations. Obtain background readings from regulated equipment designated as no detectable emissions initially, annually, and when requested by the Louisiana Department of Environmental Quality (LDEQ).

d. Task 4 - Repairing Components

- Repair all leaking components as soon as practicable, but no later than five days for first attempt at repair and 15 days for final attempt at repair.
- Monitor the repaired component to ensure the component is not leaking above the applicable leak definition.
- Place all leaking components that would require a process unit shutdown on the Delayed Repair List. Record the component ID number and an explanation of why the component cannot be repaired immediately. Also include an estimated date for repairing the equipment.

e. Task 5 - Recordkeeping

- Maintain a list of all ID numbers for all equipment subject to an equipment leak regulation.
- For valves designated as "unsafe to monitor", maintain a list of ID numbers and an explanation/review of conditions for the designation.
- Maintain detailed schematics, equipment design specifications (including dates and descriptions of any changes), and piping and instrumentation diagrams.
- Maintain the results of performance testing and leak detection monitoring, including leak monitoring results per the leak frequency, monitoring leak-less equipment, and non-periodic event monitoring.
- Attach ID tags to all leaking equipment.
- Maintain records of the equipment ID number, the instrument and operator ID numbers, and the date the leak was detected.
- Maintain a list of the dates of each repair attempt and an explanation of the attempted repair method.
- Maintain a list of the dates of successful repairs and include the results of monitoring test to determine the leak was repaired successfully.

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 proposal 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.

6. HYDROGEN CHLORIDE (HCl) TOTAL HAP EMISSIONS

Discussion.

According to the application, the HEF will not be a major source of HAP because it will not emit 10 TPY or more of a single HAP or 25 TPY or more of all HAP. The main source of HAP is steam production and is primarily comprised of HCl. The applicant estimated 4.7 TPY of HCl from each of the biomass boilers or 9.4 TPY of HCl from both boilers combined. The other meaningful HAP emission is acetaldehyde (C_2H_4O) from the fermentation and distillation step. Total facility HAP emissions are estimated by the applicant at 17.7 TPY.

HCl is formed from chloride (Cl) compounds contained in biomass. The cellulosic biomass to be used at the HEF will be typically low in Cl content as will the stillage derived therefrom.

If HCl PTE is equal to or greater than 10 TPY, then the source would be a major source of HAP and a case-by-case determination of Maximum Achievable Control Technology (MACT) is required. Such a determination would result in emission limitations for HCl and at least several other pollutants or surrogates for those pollutants such as PM-metals or organic HAP.

Applicant's HCl Proposal. The applicant estimated that emissions of HCl are less than 10 TPY and that emissions of all HAP are less than 25 TPY. Therefore, the applicant asserts, the facility is not a major source of HAP and is not subject to a case-by-case MACT determination. The applicant did not specifically propose measures to control or limit HAP emissions, including HCl.

Department's Review. According to other sources consulted by the Department, untreated woody biomass will contain less than 0.02% Cl *on a dry basis*. Dry stillage should contain a larger fraction of HCl on a dry basis because much of the feedstock biomass turns into ethanol. However the stillage contains 35 to 60% moisture. A reasonable assumption is that the stillage will contain less than 0.02% Cl by weight *on a wet basis*. The NG, ULSD FO and propane are even lower in Cl content.

The Cl can be released as HCl and or it can be bound to the ash. Cl can also condense in the form of alkali salts (NaCl and KCl) or as NH_4Cl in the presence of NH_3.

If all Cl is converted to HCl, then the pre-control annual HCl emissions from both biomass boilers are calculated as follows:

[(0.02 lb Cl/100 lb biomass)x(2000 lb biomass/ton biomass)x(36.45 lb HCl/35.45 lb Cl)]x
[(ton HCl/2000 lb HCl)x(47 tons stillage biomass/hr)x(8,760 hr/year)] = 84.7 TPY HCl

A conservative estimate is that as much as half of Cl will actually be converted to HCl. To insure that the PTE is limited to a value less than 10 TPY it will be necessary for the limestone injection system described for SO_2 control to also control HCl. The HCl will be converted to a particulate salt depending on the sorbent used. It will be necessary to control HCl emissions by approximately 80%. This should be easily accomplished by the described in-duct sorbent injection system (IDSIS) and fabric filter baghouse.

The Department will set a limit of 9.4 TPY of HCl on a 12-month rolling average, rolled monthly. Compliance shall be demonstrated by an FTIR HCl-CEMS on each BFB biomass boiler and using the procedures described in Performance Specification 15 of Appendix B of 40 CFR part 60. The 12-month limit equates to 2.14 lb/hr HCl. These limits equate to 0.0054 and 0.0049 lb HCl/mmBtu at the nominal heat input rate of 396 mmBtu/hr (2 x 198 mmBtu per boiler) and the maximum heat input rate of 436 mmBtu/hr (2 x 218 mmBtu per boiler), respectively. For each individual boiler, the limits would be 1.07 lb/hr with a nominal heat input limit of 0.0027 lb HCl/mmBtu and a maximum heat input limit of 0.0024 lb HCl/mmBtu.

The applicant can subsequently request an alternative sampling procedure (ASP) from the Department if the applicant is able to find a vendor with a HCl-CEMS operating on a different principle such as Non-dispersive infrared (NDIR) of tunable diode laser (TDL) that can demonstrate with a very high degree of confidence that the hourly emissions of HCl are less than or equal to 2.1 lb/hr and less than 9.4 TPY.

GCP in the BFB boiler, use of a non-gasification process, low Cl source biomass and control and measurement of HCl emissions will insure that organic HAP emissions including D/F will be adequately controlled.

6.1. 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 residual grain material from conventional corn-based ethanol production is a mixture of protein, fat, oils, vitamins and minerals. It can produce significant odors as it breaks down before and during drying. The dried material is typically shipped as distiller's dried grain with solubles (DDGS) and marketed as animal feed.

DDGS drying is usually accomplished by use of a recuperative TO that destroys the VOC, including the odorous species. The energy recovered is used to accomplish the drying and to provide steam elsewhere in the process.

By contrast, the stillage cake at HEF will be comprised largely of unpalatable lignin which will contain much less materials having any food value. It will have significantly less odor potential. The cellulosic ethanol process does have certain steps in common with the corn-based process that can produce odor including fermentation, distillation, product storage and shipping.

<u>Applicant's Proposal</u>.

The applicant proposes the following measures that will control VOC and odors:

- Just-in-time delivery of ethanol process feedstock biomass;
- Wet scrubbers to control water-soluble VOC from hydrolysis, fermentation and distillation steps;
- Floating roofs on product storage tanks;
- Flares to control emissions from product load out and the biogas (if not used as fuel) produced by the anaerobic digestion step in wastewater treatment;
- Use enclosed vessels for the anaerobic digestion step rather than lagoons;
- Maintaining the wet stillage cake at a temperature of 165 °F or less rather than drying;
- Prompt use of the stillage cake as fuel in the BFB biomass boilers to recover the energy and destroy potential VOC and odor emissions;
- Maintaining only small storage piles of supplemental (wood chips, bagasse, energy crops) to minimize odors;
- Prompt repair of any leaking components (such as heat exchangers) within the cooling tower 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.

<u>Department's Review</u>. 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 full odor potential will not likely be fully understood by the applicant until further operation is achieved at the demonstration plants in Jennings, LA. However, some additional common sense measures can be identified that can further reduce the potential for objectionable odors. The Department will require the following:

- The facility shall not store wet stillage cake for more than 3 days (72 hours);

- 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 and will address contingency disposal provisions for stillage that cannot be used in the boilers within 3 days of its generation; and
- The OCP shall also include provisions for storing, disposing of or recycling off-specification enzymes and bacteria that could otherwise contribute to objectionable odors.

7. BIOMASS BOILER HEAT INPUT MONITORING

Monitoring of heat input is difficult when using biomass such as cellulosic stillage as fuel as there is little experience in this practice. Stillage cake has a high moisture content compared to other fuels proposed for the biomass boilers and boiler energy will be expended to evaporate that moisture thus reducing the boiler efficiency. In the case of biogas, the boiler will operate at a higher efficiency.

To accurately calculate heat input, the applicant proposes and the Department accepts the following methodology:

Boiler Performance Test: Within 180 days of first fire on the primary fuels (stillage and biogas with natural gas for flame stabilization); the permittee shall conduct a test to determine the boiler thermal efficiency. The test shall be conducted in general abbreviated accord with ASME PTC 4, 1998. The abbreviated test procedure shall be agreed upon by all parties. The test shall be conducted when firing only the primary fuels with as close of fuel mix and heating values to the boiler design fuel mix and heating value as practical and shall be at least three hours long.

The boiler steam conditions and production rate shall be monitored and recorded during the test. The primary fuels firing rates (tons per hour and cubic feet per minute as appropriate) shall be calculated and recorded based on the steam parameters. A sample of the as-fired stillage shall be analyzed for the heating value (Btu/lb) and moisture content (%). A sample of the as-fired biogas shall be analyzed for the heating value (Btu/ft^3). The actual heat input rate (mmBtu/hour) shall be determined using two methods: (a) steam parameters with enthalpies and the measured thermal efficiency, and (b) steam parameters with enthalpies and the design boiler thermal efficiency. Results of the test shall be submitted to the Compliance Authority within 45 days of completion. The boiler thermal efficiency test shall be repeated during the 12-month period prior to renewal of any operation permit. If the tested boiler thermal efficiency is less than 90% of the design boiler thermal efficiency, then the tested thermal efficiency shall be used in any future calculations of the heat input rate until a new test is conducted.

8. AIR QUALITY IMPACT ANALYSIS

8.1. Introduction

The proposed project will increase emissions of the following PSD-pollutants at levels in excess of the respective SER: $PM/PM_{10}/PM_{2.5}$, SO_2, VOC, CO and NO_X. PM_{10}, SO_2 and NO_X are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, significant impact levels (SIL) and de minimis monitoring levels defined for them. CO is a criteria pollutant and has only AAQS, significant impact levels and de minimis monitoring levels defined for it. There are no applicable PSD increments, AAQS, significant impact or de minimis monitoring levels for VOC.

VOC and NO_X are ozone precursors and any net increase of 100 TPY or greater of either pollutant requires an ozone ambient air impact analysis including the gathering of preconstruction ambient air quality data. $PM_{2.5}$ is also a criteria pollutant and has national and state AAQS, but is not subject to PSD at this time. $PM_{2.5}$ does not have defined PSD increments (i.e. allowable increases in ambient air concentration), SIL and de minimis monitoring levels.

Major Stationary Sources Near the Proposed Highlands Ethanol Site

There are few large emission sources in Highlands County. The following tables are lists of the largest stationary sources, by pollutant, in counties adjacent to Lake Okeechobee including Highlands County. The future emissions from the HEF are also shown.

Table 11 - Largest Sources of NO_X (2008) in Counties Adjacent to Lake Okeechobee.

Owner	Site Name	TPY
Florida Power and Light (FPL)	FPL Martin Plant, Martin County	4,688
FPL	FPL Riviera Plant, Palm Beach County (PBC)	2,245
Indiantown Cogeneration	Indiantown Power Plant, Martin County	2,095
Solid Waste Authority of PBC	North Resource Recovery Facility, PBC	1,401
US Sugar Corporation	Clewiston Mill, Hendry County	886
New Hope Power Company	Okeelanta Cogeneration Plant, PCB	826
Sugar Cane Growers Coop	Sugar Cane Growers Coop, PBC	514
Osceola Farms	Osceola Farms, PBC	392
Tampa Electric Company (TECO)	TECO Phillips Station, Highlands County	353
Florida Gas Transmission (FGT)	FGT Station 20 St. Lucie	308
Verenium/Highlands Ethanol LLC	**HEF, Highlands County**	**156**
Florida Municipal Power Agency	Treasure Coast Energy Center, St. Lucie County	104

Table 12 - Largest Sources of PM/PM_{10} (2008) in Counties Adjacent to Lake Okeechobee

Owner	Site Name	TPY
FPL	FPL Martin Plant, Martin County	844
Osceola Farms	Osceola Farms, PBC	333
US Sugar Corporation	Clewiston Mill, Hendry County	323
Sugar Cane Growers Coop	Sugar Cane Growers Coop, PBC	257
FPL	FPL Riviera Plant, PBC	173
New Hope Power Company	Okeelanta Cogeneration Plant, PBC	124
Solid Waste Authority (SWA) PBC	North County Resource Recovery Facility, PBC	102
Verenium/Highlands Ethanol LLC	**HEF, Highlands County**	**34**
Okeelanta Corporation	Okeelanta Sugar Refinery, PBC	21
TECO	TECO Phillips Station, Highlands County	10

Table 13 - Largest Sources of SO_2 (2008) in Counties Adjacent to Lake Okeechobee

Owner	Site Name	TPY
FPL	FPL Martin Plant, Martin County	7,734
FPL	FPL Riviera Plant, PBC	2,643
Indiantown Cogeneration	Indiantown Power Plant, Martin County	2,018
Waste Management	Berman Landfill, Okeechobee County	1,080
Sugar Cane Growers Coop	Sugar Cane Growers Coop, PBC	426
New Hope Power Company	Okeelanta Cogeneration Plant, PBC	250
SWA of PBC	North County Resource Recovery Facility, PBC	248
TECO	TECO Phillips Station, Highlands County	245
U.S. Sugar Corporation	Clewiston Mill, Hendry County	151
Verenium/Highlands Ethanol LLC	**HEF, Highlands County**	**104**
PBC Water Utilities	PBC Water Utilities	72

Table 14 - Largest Sources of CO (2008) in Counties Adjacent to Lake Okeechobee

Owner	Site Name	TPY
U.S. Sugar Corporation	Clewiston Mill, Hendry County	11,774
Osceola Farms	Osceola Farms, PBC	11,456
Sugar Cane Growers Coop	Sugar Cane Growers Coop, PBC	10,655
New Hope Power Company	Okeelanta Cogeneration Plant, PBC	2,254
FPL	Martin Plant, Martin County	1,451
SWA of PBC	North County Resource Recovery Facility, PBC	772
Southern Gardens Citrus Processing	Southern Gardens Clewiston, Hendry County	622
FPL	Riviera Plant, PBC	443
Louis Dreyfus Citrus	Indiantown Plant, Martin County	370
Waste Management	Berman Landfill, Okeechobee County	250
Verenium/Highlands Ethanol LLC	**HEF, Highlands County**	**192**
Indiantown Cogeneration	Indiantown Power Plant, Martin County	158

Table 15 - Largest Sources of VOC (2008) in Counties Adjacent to Lake Okeechobee

Owner	Site Name	TPY
Southern Gardens Citrus Processing	Southern Gardens Clewiston, Hendry County	1,066
Osceola Farms	Osceola Farms, PBC	635
Sugar Cane Growers Coop	Sugar Cane Growers Coop, PBC	570
Tropicana Manufacturing	Tropicana Ft. Pierce, St. Lucie County	551
U.S. Sugar Corporation	Clewiston Mill, Hendry County	451
Louis Dreyfus Citrus	Indiantown Plant, Martin County	366
FPL	Martin Plant, Martin County	195
Genpak, LLC	Genpak Plastics, Highlands County	151
S2 Yachts	S2 Yachts, St. Lucie County	98
Verenium/Highlands Ethanol LLC	**HEF, Highlands County**	**71**
FPL	Riviera Plant, PBC	37

The information is from annual operating reports submitted to the Department. The largest stationary sources of air pollution in Highlands County including the future HEF project are small when compared to emissions from industries within some of the nearby counties, including: sugar mills in Hendry and Palm Beach Counties; power plants in Martin and Palm Beach Counties; and several citrus processing plants. They are also small compared with emissions (not shown) from industries in counties to the north such as fertilizer, citrus and power plants in Polk and Osceola Counties.

8.2. Ambient Air Monitoring Surrounding Lake Okeechobee

The Department and the PBC Health Department Local Program operate monitors at seven sites measuring NO_X, SO_2, ozone, PM_{10}, or $PM_{2.5}$ (also called PM_{fine}) in the counties surrounding Lake Okeechobee. The Archbold Biological Station ozone monitor is located in Highlands County. There are PM_{10} and $PM_{2.5}$ monitors in nearby rural Belle Glade, which is the center of the sugar industry. There are ozone and $PM_{2.5}$ monitors in the rural to urban transition area in Royal Palm Beach. The rest are along the east coast in the communities of Riviera Beach, Delray Beach and West Palm Beach (WPB Lantana). Air quality measurements from 2008 at regulatory monitors are summarized in the Table 16 below.

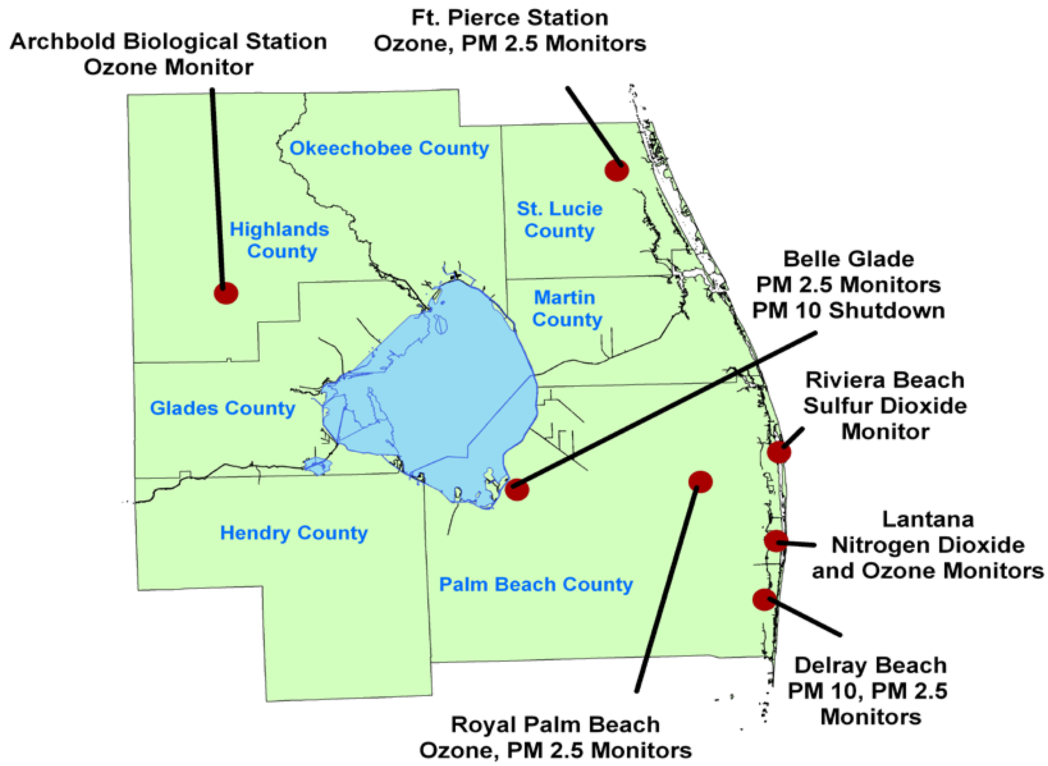

Figure 8 - Air Monitoring Network in Counties Surrounding Lake Okeechobee

8.3. Discussion of Ambient Air Quality in Highlands County - Ozone

On March 27, 2008 the U.S. Environmental Protection Agency (EPA) published a final rule (since vacated) reducing the 8-hour ozone AAQS from 85 to 75 parts per billion (ppb). The average of the annual fourth highest measurements (design value) over the period 2006-2008 is the value that is compared to the stayed ozone AAQS for determining whether an area would have been in attainment. The design values for all counties in Florida are shown in Figure 9 below. For the Highlands monitor, the design value was 73 ppb and Highlands County was in attainment with the since stayed ozone standard.

8.4. Air Quality Impact Analysis

Significant Impact Analysis

SIL are defined for SO_2, CO, PM/PM_{10}, and NO_X. A significant impact analysis (SIA) 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.

In order to conduct a SIA, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. The models used in this analysis and any required subsequent modeling analyses are described below. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate SILs for the PSD Class II Area (everywhere except the closest Class I Area, the Everglades National Park).

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 receptor grid consisted of receptors spaced at 25-meter (m) intervals around the facility fence line. The remaining receptors were spaced at 50 m from the property line out to 500 m, 100 m out to 1 km, 200 m out to 2 km, 400 m out to 4 km, 800 m out to 8 km, 1,600 m out to 16 km and 3,200 m out to 32 km from the property line.

Table 16 - Ambient Air Quality Measurements Nearest to the Project Site (2008)

Pollutant	Location	Averaging Period	Ambient Concentration				
			High	2nd High	Mean	Standard	Units [a]
PM_{10}	Belle Glade	24-hour	79	49		150 [b]	$\mu g/m^3$
		Annual			19	50 [c]	$\mu g/m^3$
$PM_{2.5}$	Belle Glade	24-hour	29	20		35 [d]	$\mu g/m^3$
		Annual			6	15 [e]	$\mu g/m^3$
SO_2	Riviera Beach	3-hour	4	4		500 [f]	ppb
		24-hour	4	4		100 [f]	ppb
		Annual			2	20 [c]	ppb
NO_2	WPB Lantana	Annual			8	53 [c]	ppb
CO	WPB Lantana	1-hour	2	2		35 [f]	ppm
		8-hour	1	1		9 [f]	ppm
Ozone	Highlands Archbold	8-hour	77	77		75 [g]	ppb
		4^{th} highest high			73	75 [g]	ppb

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 98^{th} percentile of 24-hour concentrations.
e. Three year average of the weighted annual mean.
f. Not to be exceeded more than once per year.
g. Three year average of the 4^{th} highest daily maximum.

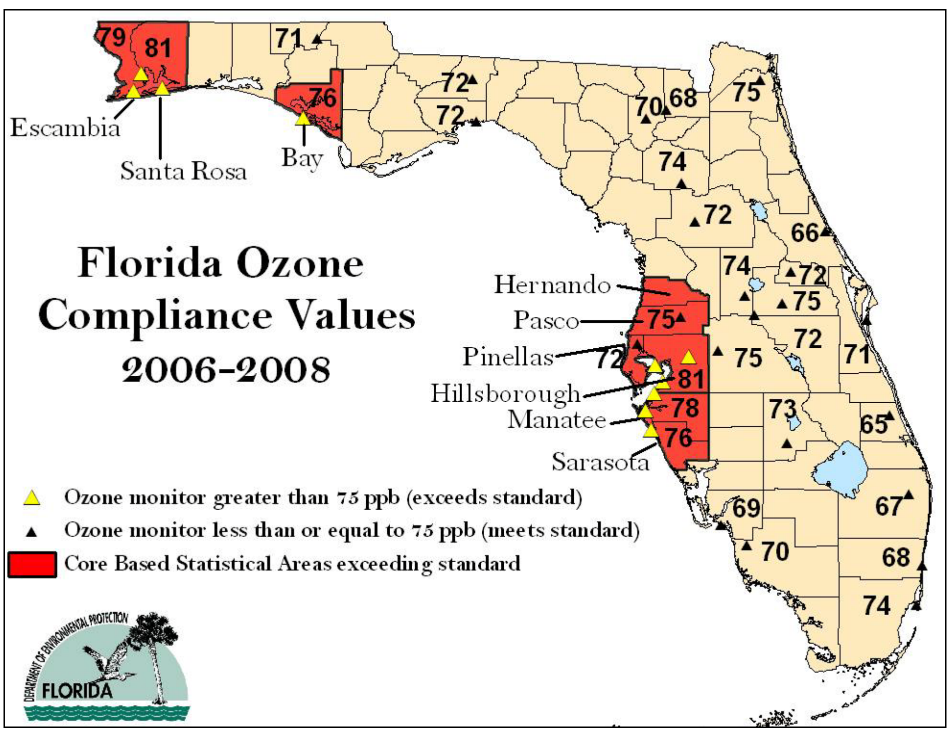

Figure 9. Florida ozone compliance values based on data reported during 2006-2008

If this modeling at worst-load conditions shows ground-level increases less than the 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.

The results of applicant's SO_2, CO, PM/PM_{10} and NO_X air quality SIA for this project are shown below in Table 17. Maximum predicted impacts from all pollutants are greater than the applicable SIL for the Class II area except for CO. These values are tabulated in the table below and compared with existing ambient air quality measurements from the local ambient monitoring network. It is clear that maximum predicted impacts from the project are much less than the respective AAQS.

Table 17 - Maximum Predicted Air Quality Impacts from the HEF for Comparison to the PSD Class II SILs

Pollutant	Averaging Time	Max Predicted Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	2008 Baseline Concentrations ($\mu g/m^3$)	Ambient Air Standards ($\mu g/m^3$)	Significant Impact?
PM_{10}	Annual	5	1	~20	50	Yes
	24-Hour	23	5	~80	150	Yes
SO_2	Annual	7	1	~5	80	Yes
	24-Hour	43	5	~10	365	Yes
	3-hour	104	25	~10	1300	Yes
NO_2	Annual	4	1	~15	100	Yes
CO	1-hour	138	2,000	~2300	40,000	No
	8-hour	75	500	~1150	10,000	No

For the Class I analysis, 360 receptors were located along a perimeter 50 km away from the property line. While the Everglades National Park (ENP) is 154 km away from the proposed project location, the applicant provided the SIA for 50 km out using Class II SIA (AERMOD) modeling methods to demonstrate that no further Class I analyses should be required based on distance and projected emission rates.

Maximum air quality impacts from the proposed project at a distance of 50 km are summarized in the Table 18. The results of the initial PM/PM_{10}, NO_X and SO_2 air quality impact analyses for this project indicated that maximum predicted impacts are less than the applicable SILs for the Class I area.

Table 18 - Maximum Air Quality Impacts from the Highlands Ethanol Project for Comparison to the PSD Class I SILs

Pollutant	Averaging Time	Max. Predicted Impact at 50 km $\mu g/m^3$)	Class I SIL ($\mu g/m^3$)	Significant Impact?
PM_{10}	Annual	0.004	0.2	No
	24-hour	0.08	0.3	No
NO_2	Annual	0.01	0.1	No
SO_2	Annual	0.005	0.1	No
	24-hour	0.17	0.2	No
	3-hour	0.99	1	No

The National Park Service (NPS) conducted a brief review and advised that it "does not anticipate any significant impacts on resources at the ENP." The NPS did not require any additional modeling or analyses for the proposed project. The conclusion is logical given the distance from the source to the ENP and the low relative and absolute emissions of the source compared with the previously discussed large stationary sources that are more likely to affect the ENP. Additionally, if modeled together (increment expanding and consumptive sources) the overall expansion of increment (improvement) due to regional power plant emissions reductions would overwhelm the small consumption of increment by the HEF. Thus a multisource modeling effort would likely show improvement in air quality.

Notwithstanding the foregoing discussion, for larger projects (such as the FPL Turkey Point Unit 5 or the cancelled Glades coal-fueled project), use of the Class I model CALPUFF is more appropriate.

Preconstruction Ambient Monitoring Requirements

A preconstruction monitoring analysis is performed for those pollutants with listed de minimis impact levels. These are levels, which, if exceeded, would require pre-construction ambient monitoring. For this analysis, as was done for the SIA, the applicant used the proposed project's emissions at worst load conditions as inputs to the models. As shown in Table 19 below, the maximum predicted impacts for PM/PM_{10} and SO_2 were greater than listed de minimis impact levels. Therefore, a pre-construction monitoring analysis is required for PM/PM_{10}, and SO_2.

Table 19. Maximum Air Quality Impacts for Comparison to the De Minimis Ambient Impact Levels

Pollutant	Averaging Time	Max Predicted Impact (μg/m^3)	De Minimis Level (μg/m^3)	2008 Baseline Concentrations (μg/m^3)	Impact Greater Than De Minimis?
PM_{10}	24-hour	23	10	~80	Yes
NO_2	Annual	4	14	~15	No
SO_2	24-hour	43	13	~10	Yes
CO	8-hour	75	575	~1150	No

There are no PM_{10} or SO_2 monitors in Highlands County. However, there are particulate monitors on the other side of the lake in Palm Beach County not directly on the coast near larger sources of particulate which are in attainment with the standards. Also, there are monitors located at various sites in Florida near large sources of SO_2. The SO_2 monitor near the FPL Riviera power plant is in attainment with the standards. In 2008, the Riviera facility emitted 2,775 tons of SO_2 compared to the 107 tons expected from the proposed facility. These monitors provide sufficient data to satisfy preconstruction monitoring needs. Given the low emissions from the future predicted Highlands Ethanol operation, preconstruction monitoring at the site would yield little useable information.

Predicted NO_X emissions from the proposed project are above 100 TPY. Therefore, an evaluation for preconstruction monitoring is required for ozone. There is an ozone monitor in Highlands County. This monitor is in attainment with the new ozone standard. The nature of ozone formation from its precursors (NO_X and VOC) and meteorological factors is such that monitoring is focused on regional effects. The single monitor is sufficient to define ozone in Highlands County, whereas some of the coastal counties require more than a single monitor due to differences between shoreline and inland meteorology.

Based on the preceding discussions, the only additional detailed air quality analyses required by the PSD regulations for this project are the following:

- A multi-source AAQS and PSD increment analysis for SO_2, PM_{10} and NO_2 in the Class II area; and
- An analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

Models and Meteorological Data Used in the Foregoing Air Quality Analysis

PSD Class II Area: The AERMOD modeling system was used to evaluate the pollutant emissions from the proposed project in the surrounding Class II Area. AERMOD was approved by the EPA in November 2005. 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. The stacks associated with this project all satisfied the good engineering practice (GEP) stack height criteria.

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 National Weather Service at the Palm Beach International Airport and the Miami International Airport respectively. The 5-year period of meteorological data was from 2001 through 2005. A sensitivity analysis was also completed using surface data from the facility site. The meteorological data used were in accordance with the EPA AERMOD Implementation Guide. The modeling results are the highest concentrations from both sets of AERMET meteorological data.

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. 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 20 below.

Table 20 - PSD Class II Increment Analysis

Pollutant	Averaging Time	Max Predicted Impact ($\mu g/m^3$)	Allowable Increment ($\mu g/m^3$)	Impact Greater Than Allowable Increment?
PM_{10}	24-hour	23	30	No
	Annual	5	17	No
NO_2	Annual	8	25	No
SO_2	3-hour	102	512	No
	24-hour	44	91	No
	Annual	9	20	No

The results of the PSD Class II analysis are conservative. Specifically, the inventory of all increment-consuming sources did not include sources that have expanded increment, i.e. shut down or reduced emissions since the baseline date and potential emissions were used as inputs to the model instead of actual emissions. For example, in the previous ten years the Florida Power and Light Martin Power Plant has expanded increment by reducing NO_X and SO_2 by approximately 5,000 and 2,000 TPY respectively.

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 takes into account all sources of a particular pollutant that are not explicitly modeled. The maximum predicted annual and maximum predicted high, second high short term average for the AAQS analysis are summarized in Table 21 below. As shown in this table, emissions from the proposed facility are not expected to significantly cause or contribute to a violation of an AAQS.

Table 21 - Ambient Air Quality Impacts

Pollutant	Averaging Time	Major Sources Impact ($\mu g/m^3$)	Background Conc. 2003- 2007 ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Total Impact Greater Than AAQS?	Florida AAQS ($\mu g/m^3$)
PM_{10}	24-hour	23	42	65	No	150
	Annual	5	20	25	No	50
NO_2	Annual	8	19	27	No	100
SO_2	3-hour	102	11	113	No	1300
	24-hour	44	11	55	No	365
	Annual	9	5	14	No	80

8.5. Additional Impacts Analysis

Impact on Soils, Vegetation, and Wildlife

The Highlands Ethanol proposed project will not contribute to a violation of the PSD Increment or AAQS. Further, the applicant provided a modeling screening analysis using AERMOD to demonstrate that the proposed project will not have an adverse impact on soils and vegetation. According to the applicant, the modeling results show that impacts from SO_2 and NO_2 are much less than the EPA screening levels.

Growth-Related Impacts Due to the Proposed Project

According to the applicant, the proposed project will provide up to 65 new permanent employees and up to 500 short term employees during the eighteen month construction of the facility. The applicant states that this increase in workers will not significantly impact the air quality in the region since this growth is minimal when compared to the population of Highlands County.

Also according to the applicant, there will be an increase in truck traffic during the construction phase of the project. Once in operation, the applicant anticipates approximately 100 trucks per day, along with additional employee vehicles.

Growth-Related Air Quality Impacts since 1977

The population of Highlands County doubled between 1977 and 2008 from approximately 47,000 to 97,000 but remains relatively small. The applicant provided aerial photos of the area surrounding the proposed facility. Upon review of the historical topographic maps, the applicant determined that the immediate area has remained unchanged since the 1970s and agricultural in nature. With regards to utilities in Highlands County, the small Progress Energy Avon Park Power Plant has been operating since the 1950s and the small Tampa Electric Company Phillips Power Plant has been operating since the early 1980s. Highlands County ozone monitoring was initiated in 2001 and has been in attainment throughout its history.

9. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the Draft permit. This determination is based on a technical review of the complete application, reasonable assurances provided by the applicant, and the conditions specified in the Draft permit. David Read is the project engineer responsible for reviewing the application and drafting the permit changes. He may be contacted at 850/414-7268 and at david.read@dep.state.fl.us .