# PSD APPLICATION FOR ETHANOL BIOREFINERY AND COGENERATION FACILITY

**Highlands EnviroFuels, LLC**
**Riverview, Florida**

PSD Application


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**Distribution:** **FDEP – 7 copies**
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**May 2011**

**103-87668**


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## List of Acronyms and Abbreviations

| | |
|---|---|
| $\mu g/m^3$ | micrograms per cubic meter |
| AAQS | ambient air quality standard |
| Acfm | actual cubic feet per minute |
| AMP | alternative monitoring procedure |
| AQRV | air quality-related value/visibility test |
| ATP | adenosine triphosphate |
| BACT | best available control technology |
| bhp | brake horsepower |
| BPIPPRM | Building Profile Input Program |
| Btu/lb | British thermal units per pound |
| CAA | Clean Air Act |
| CAIR | clean air interstate rule |
| CEC | cation exchange capacity |
| CEMS | continuous emission monitoring system |
| CFR | Code of Federal Regulations |
| $CH_4$ | methane |
| CI ICE | compression ignition internal combustion engines |
| CO | carbon monoxide |
| $CO_2$ | carbon dioxide |
| COMS | continuous opacity monitoring system |
| ENP | Everglades National Park |
| ESP | electrostatic precipitator |
| °F | degrees Fahrenheit |
| F.A.C. | Florida Administrative Code |
| FDEP | Florida Department of Environmental Protection |
| FGD | flue gas desulfurization |
| FLAG | Federal Land Manager's Air Quality Relative Values Workgroup |
| FLM | Federal Land Manager |
| ft | foot |
| g/kW-hr | grams per kilowatt-hour |
| gal/day | gallons per day |
| gal/yr | gallons per year |
| GCPs | good combustion practices |
| GEP | Good Engineering Practice |
| GHG | greenhouse gases |
| $g/m^2$ | grams per square meter |
| gpm | gallons per minute |
| gr/dscf | grain per dry standard cubic foot |
| $H_2SO_4$ | sulfuric acid |
| HAP | hazardous air pollutant |
| HCl | hydrochloric acid |
| HEF | Highlands EnviroFuels, LLC |
| Hg | mercury |
| hr/yr | hours per year |
| HSH | highest, second-highest |
| ID | induced draft |
| km | kilometer |
| kW | kilowatt |
| lb/hr | pounds per hour |
| lb/MMBtu | pound per million British thermal units |
| lb/MW-hr | pound per megawatt hour |
| LDAR | leak detection and repair |
| m | meter |

| | |
|---|---|
| MACT | Maximum Available Control Technology |
| MMBtu/hr | million British thermal units per hour |
| MMscf/yr | million standard cubic feet per year |
| msl | mean sea level |
| MSW | municipal solid waste |
| MTBE | methyl tertiary-butyl ether |
| MWC | municipal waste combustor |
| NAAQS | National Ambient Air Quality Standards |
| $Na_2CO_3$ | sodium carbonate |
| $Na_2SO_3$ | sulfite initially, |
| $Na_2SO_4$ | sulfate |
| NAD83 | North American Datum 1983 |
| NAOH | sodium hydroxide |
| NED | National Elevation Data |
| NESHAPs | National Emission Standards for Hazardous Air Pollutants |
| NMHC | non-methane hydrocarbon |
| $NO_2$ | nitrogen dioxide |
| $NO_x$ | nitrogen oxides |
| NSPS | new source performance standards |
| NSR | new source review |
| NWA | National Wilderness Area |
| $O_3$ | ozone |
| OFA | overfire air |
| Pb | lead |
| PM | particulate matter |
| $PM_{10}$ | particulate matter less than 10 microns |
| $PM_{2.5}$ | particulate matter less than 2.5 microns |
| ppm | parts per million |
| ppmvd | parts per million by volume dry |
| PSD | prevention of significant deterioration |
| RBLC | RACT/BACT/LAER Clearinghouse |
| RGVSG | Rio Grande Valley Sugar Growers |
| RSW | Fort Myers Southwest Florida Regional Airport |
| RTO | regenerative thermal oxidation |
| SAM | sulfuric acid mist |
| SCRAM | Support Center for Regulatory Air Models |
| SIA | significant impact area |
| SIP | Florida's State Implementation Plan |
| SNCR | selective non-catalytic reduction |
| $SO_2$ | sulfur dioxide |
| SOCMI | synthetic organic chemical manufacturing industry |
| SR | State Road |
| TDS | total dissolved solids |
| TIA | Tampa International Airport |
| TPD | tons per day |
| TPY | tons per year |
| TSP | total suspended particulate |
| TTN | Technology Transfer Network |
| USDA | U.S. Department of Agriculture |
| USGS | U.S. Geological Survey |
| UTM | Universal Transverse Mercator |
| VMT | vehicle miles traveled |
| VOC | volatile organic compound |
| VOL | volatile organic liquid |

## 1.0 INTRODUCTION

Highlands EnviroFuels, LLC (HEF) is proposing to construct and operate an advanced biofuel ethanol biorefinery and biomass cogeneration power plant on a 75-acre industrial site, located approximately 0.5 mile south-southwest of the intersection of U.S. 27 and State Road (SR) 70, south of Lake Placid, in Highlands County, Florida (see Figure 1-1). The HEF facility will have a design production capacity of 30 million gallons per year (MMgal/yr) of ethanol using feedstock of sugarcane and sweet sorghum grown on nearby farmland. The facility will combust primarily sugarcane bagasse and sweet sorghum bagasse, generated from the ethanol production process, in a boiler to generate steam and up to 30 megawatts (MW) gross electric generation.

Currently in the U.S. there is an increasing demand for fuel grade ethanol. The federal government has recently issued approval for up to 15 percent ethanol to be used in gasoline for motor vehicles manufactured in 2001 and after, increasing from the current 10 percent ethanol allowance. Ethanol, which is used primarily as an "oxygenate" in gasoline, reduces the dependence on foreign energy supplies, while reducing ozone air pollution. Ethanol has also been a replacement for methyl tert-butyl ether (MTBE) in gasoline. MTBE is a toxic chemical that persists once released into the environment.

The federal Energy Independence and Security Act of 2007 (EISA) requires the production of 14 billion gallons per year (gal/yr) of renewable ethanol fuel in the U.S. in 2011, increasing to 36 billion gal/yr by the year 2022. The U.S. Environmental Protection Agency (EPA) promulgates a Renewable Fuels Standard (RFS) which mandates the amount of renewable fuels that must be produced for transportation fuels each year. The 2011 RFS includes the production of 14 billion gal/yr of renewable fuel (ethanol), as well as 1.35 billion gal/yr of advanced biofuels. The proposed HEF facility will aid in filling this requirement by producing up to 36 MMgal/yr (20 percent over design capacity) of advanced ethanol biofuel.

The use of dedicated biomass energy crops such as sugarcane and sweet sorghum, neither of which are linked to food use or food pricing, as the raw material for biofuels has a number of advantages as compared to food-based feedstock for ethanol such as corn:

- Increased use of agriculture to produce transportation fuels
- Reduction in imported petroleum used for transportation fuel
- Increased yield of ethanol per acre of cropland
- No impact on food supply and food prices
- Relatively low feedstock cost
- Less fertilizer and water usage compared to corn-based ethanol
- Significantly greater reduction in greenhouse gas (GHG) emissions across the entire life cycle
- Virtually no fossil fuel use in the conversion process to ethanol
- Superior energy balance of approximately 8-to-1

The use of biomass fuels to provide the energy needs of the proposed facility (steam and electricity), as well as generating significant amounts of electricity for sale to the electric grid, has the added advantages of the use of renewable fuels (biomass) for power generation and very low emissions of GHGs.

The primary fuels for the cogeneration biomass boiler will be sugarcane bagasse and sweet sorghum bagasse, which will be used in approximately equal quantities on an annual basis. Wood and natural gas will be used as backup or supplemental fuel. The biomass boiler will be suspension-fired with a vibrating grate. The boiler will employ the following air pollution control equipment:

- Selective non-catalytic reduction (SNCR) and a modern overfire air (OFA) system for minimizing emissions of nitrogen oxides ($NO_x$)
- Low-$NO_x$ burners (LNBs) for firing natural gas
- Mechanical collectors and an electrostatic precipitator (ESP) will be used for control of particulate matter (PM) and metals emissions
- Use of very low-sulfur fuels and a dry sorbent injection (DSI) system to control emissions of sulfur dioxide ($SO_2$), hydrogen chloride (HCl), and other acid gases
- Use of clean biomass and fossil fuels will also control emissions of mercury (Hg), lead (Pb), and other metals
- Modern OFA system will control emissions of carbon monoxide (CO) and volatile organic compounds (VOCs)

The proposed HEF facility requires an air construction permit and pre-construction prevention of significant deterioration (PSD) permit approval prior to commencing construction. PSD approval requires submission of air quality assessments for determining the facility's compliance with state and federal new source review (NSR) regulations, including addressing applicable PSD requirements. The critical aspects of these assessments include conducting the air quality impact analyses using appropriate air dispersion models and performing the best available control technology (BACT) analyses to evaluate the selected emission control technologies.

The HEF facility will not be classified as a "major" source of hazardous air pollutants (HAPs), as its facility-wide HAPs emission will be less than 10 tons per year (TPY) for any individual HAP, and less than 25 TPY for the total of all HAPs combined. Therefore, the HEF boiler will be subject to maximum achievable control technology (MACT) regulations for "area" sources, and a case-by-case MACT analysis is not required. The HEF biomass boiler will be subject to the recently promulgated MACT standards for Industrial Boilers located at area sources.

The EPA has implemented regulations requiring a PSD review for new and modified sources with air emissions above certain threshold amounts. EPA's PSD regulations are promulgated under Title 40, Parts 52.21 and 51.166 of the Code of Federal Regulations (40 CFR 52.21 and 51.166). Florida's PSD regulations are codified in Rule 62-212.400, Florida Administrative Code (F.A.C.). The Florida PSD regulations incorporate the requirements of EPA's PSD regulations. Based on the potential emissions from the proposed facility, PSD review is required for each of the following regulated pollutants:

- PM as total suspended particulate matter (TSP)
- PM with aerodynamic diameter less than or equal to 10 micrometers ($PM_{10}$)
- PM with aerodynamic diameter less than or equal to 2.5 micrometers ($PM_{2.5}$)
- $SO_2$
- $NO_x$
- CO
- VOCs
- Sulfuric acid mist (SAM)

Highlands County has been designated as an attainment area for all criteria pollutants [i.e., attainment for ozone ($O_3$), $PM_{10}$, $SO_2$, CO, and nitrogen dioxide ($NO_2$); unclassifiable for Pb] and is a PSD Class II area for $PM_{10}$, $PM_{2.5}$, $SO_2$, and $NO_2$. Therefore, the PSD review will follow regulations pertaining to these designations. For each pollutant subject to PSD review, the following analyses are required:

1. Ambient monitoring analysis, unless the net increase in emissions due to the proposed Facility causes impacts that are below specified significant impact levels
2. Application of BACT for each new emissions unit that emits the PSD pollutant
3. Air quality impact analysis, unless the net increase in emissions due to the proposed Facility causes impacts that are below specified significant impact levels
4. Additional impact analysis (impact on soils, vegetation, visibility, and growth), including impacts on PSD Class I areas

EPA has deferred PSD review for greenhouse gases (GHGs), per their guidance document and recent proposed PSD rule changes. Therefore, PSD and BACT review for GHGs is not presented in this report.

This PSD permit application addresses the above requirements and is organized into six additional sections, followed by the appendices:

- Description of the project, including air emission sources and pollution control equipment, is presented in Section 2.0
- Regulatory applicability analysis of the proposed project is presented in Section 3.0
- The ambient air monitoring analysis is presented in Section 4.0
- The BACT analysis is presented in Section 5.0
- The air quality impact analysis is presented in Section 6.0
- Additional impact analysis is presented in Section 7.0

Supporting documentation is presented in the appendices.

# 2.0 PROJECT DESCRIPTION

## 2.1 General

HEF is proposing to construct and operate an advanced biofuel ethanol biorefinery and cogeneration power plant in Highlands County, Florida, just southwest of the intersection of U.S. 27 and SR 70, south of Lake Placid, Florida (see Figure 2-1). The facility will have a design production capacity of 30 MMgal/yr and a maximum production capacity of 36 MMgal/yr of ethanol, using feedstock of sugarcane and sweet sorghum, which will be grown on adjacent farmlands. The facility will generate up to 30 MW (gross) and 20 MW (net) of electricity for sale to the electrical grid. This section provides a description of the proposed facility and potential emission estimates. The cogeneration boiler will supply the ethanol production process with steam up to 304 days per year, while also generating electrical energy for the plant and for sale to the electric grid for up to 335 days per year. During the periods when the ethanol production process is not operating, the biomass boiler may continue to operate to produce steam and electrical energy.

### *2.1.1 Site Location*

The HEF facility property boundaries in relation to the surrounding area are shown in Figure 2-1. The property comprises approximately 75 acres, and is located in an industrial park. The industrial park comprises approximately 250 acres in total, which are zoned I-2 Heavy Industrial. A Georgia-Pacific box plant, currently shut down, is located immediately northeast of the HEF site. A citrus packaging plant, also currently shut down, is located immediately northwest. The nearest residence (a trailer park) is approximately 0.74 mile east of the proposed site, and the town of Lake Placid is approximately 5 miles north.

The HEF site will encompass approximately 75 acres. The ethanol process equipment, biomass boiler, electric turbine generator, biomass storage area, and related equipment will be located on approximately 15 acres (see Figure 2-2). The area surrounding the industrial park consists primarily of agricultural fields, such as citrus groves and pasture land. In order to supply the proposed plant with biomass feedstock, sugarcane will be grown on 15,000 to 18,000 acres of land, and sweet sorghum will be grown on approximately 15,000 to 18,000 acres as well. Two crops of sweet sorghum will be grown per year, while one crop of sugarcane will be grown annually.

The site elevation is nominally 120 to 140 feet (ft) with respect to mean sea level (msl). The facility grade elevation, including biomass boiler building floor elevation, will be at 15 ft elevation compared to the surrounding terrain (135 ft above msl). The terrain surrounding the site is flat to gently rolling.

### *2.1.2 Overall Process Flow*

An overall process flow diagram of the proposed HEF facility is shown in Figure 2-3. The process begins with sugarcane and sweet sorghum delivered by trucks from the fields. The biomass feedstock is then prepared to enter the ethanol production process. Sugarcane and sorghum bagasse is produced from this process and is sent to the biomass boiler as fuel. Any excess bagasse will be sent to the biomass storage area. During times when sugarcane or sweet sorghum cannot be delivered to the facility, or during off-crop periods, wood fuel may be utilized to continue to generate steam and power to make ethanol and sell electricity to the grid. The biomass boiler will produce steam for the ethanol production process and also to generate electricity in one (1) steam electric turbine generator.

Intermediate ethanol will be stored in a floating roof tank. Denaturant/gasoline will be received on site, stored, and mixed with 200-proof ethanol to a 2- to 5-percent denaturant/gasoline blend prior to storage in the fuel ethanol floating roof storage tank. Fuel ethanol will be loaded out from truck and railcar loading racks. In-line blending of gasoline and ethanol may also occur at the loading rack to load out E-85 product (85-percent ethanol/15-percent gasoline). A flare will be utilized to control gasoline and ethanol vapor emissions from the truck and railcar loading rack.

## 2.2 Ethanol Production Process

The proposed facility will process up to approximately 900,000 TPY of sugarcane and 900,000 TPY of sweet sorghum to produce up to 36 MMgal/yr of advanced biofuel ethanol. Sugarcane will be harvested primarily during November through March, while sweet sorghum will be harvested from June through October. The facility capacity will be approximately 120,000 gallons per day (gal/day) of ethanol (daily average). The annual ethanol production is based on an expected operating schedule of 304 days per year for the ethanol production process. A flow diagram of the ethanol production process is shown in Figure 2-4.

### *2.2.1 Sweet Sorghum Receiving*

Both sugarcane and sweet sorghum stalks will be harvested as 6-inch to 12-inch billets from adjacent and nearby agricultural lands to supply the facility. The harvesting methods employed will ensure that "trash", i.e., cane and sorghum leaves and tops, will be minimized in the delivered biomass. Many of the chemical constituents of interest for this air permit application, such as chlorine, are concentrated in the leaves and tops of the plant. The harvesting method will also reduce the amount of soil brought in with the biomass. It is expected that "trash" will constitute less than 8 percent of the delivered biomass to the facility.

Sugarcane and sweet sorghum will arrive from the adjacent agricultural fields to the HEF facility via trucks or rail. The trucks and railcars will be weighed on a weighing bridge as they enter the unloading area. The sugarcane or sorghum in the trucks is then transferred to the feed table via a tipping trailer. Railcars will be bottom dumped into a feed hopper, which feeds the feed table. The feed table is equipped with chains that convey the sugarcane and sweet sorghum billets toward the main conveyor that feeds the juice extraction system.

### 2.2.2 Juice Extraction

A state-of-the-art system will be utilized to remove sucrose from the sugarcane and sweet sorghum entering the process. First the biomass will be passed through high-efficiency knives and a heavy-duty shredder to increase the surface area of the material. From the shredder, the biomass passes to a belt conveyor and then to the diffuser. Any excess biomass is returned to the belt conveyor via the excess biomass conveyor and a chute.

The diffuser is designed to carry a uniform layer of biomass (sugarcane or sweet sorghum) through the diffuser and across the entire width of the diffuser to obtain maximum sucrose removal. The diffuser consists of a slat-type conveyor with a fixed bottom employing perforated screens. Beneath the screens, several semi-cylindrical transversal juice receivers will be installed.

Imbibition water is fed into the juice trough and falls onto the processed biomass mat, percolates through the fibers, passes across the screen, and is collected in the last juice receiver. Due to the flooding conditions in the diffuser, the sucrose contained in the biomass is washed out and passes into the solution, which is at lower sucrose concentration. From the juice receiver, this solution with low sucrose concentration is recirculated upstream back to the juice trough and falls again onto the biomass mat. This recirculation continues to create a countercurrent pattern and a constant sucrose concentration gradient between the biomass mat moving downstream and the recirculating juice moving upstream. As a result, the sucrose concentration of the juice increases gradually until it reaches the maximum concentration in the juice receiver situated at the front end of the diffuser.

The biomass exiting the diffuser is termed "bagasse." This bagasse is very similar in quality to sugarcane bagasse resulting from the sugarcane milling process in Florida. The moisture content of the bagasse when it leaves the diffuser is approximately 80 percent. To reduce the moisture content further, the bagasse is sent through a dewatering mill system. The mill presses the bagasse until the moisture content is reduced to approximately 50 percent. The bagasse is then conveyed directly to the biomass boiler. The liquid stream from the dewatering mill still contains some sucrose, and is collected in a surge tank and re-circulated to the diffuser.

The diffuser will be oversized by approximately 20 percent. This will allow the facility to increase ethanol production on a daily basis in the event that a freeze or other weather conditions make it desirable to rapidly harvest the crop.

### 2.2.3 Juice Filtration

From the juice receiver, the juice is pumped to a juice screen which separates fine particles prior to evaporation. Fine particles are recycled into the diffuser where they ultimately become part of the bagasse. The screened juice is then sent to the juice storage tank. The juice pH is adjusted as necessary to control corrosion.

### 2.2.4 Juice Evaporation

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

### 2.2.5 Pre-Fermentation and Fermentation

Yeast has long been used in the brewery industry to produce ethanol from hexoses (6-carbon sugars). This process is commonly known as "fermentation". Yeast cells are effective for ethanol processes as they are relatively tolerant to high ethanol concentrations and are able to grow at low pH to avoid bacterial contamination. During fermentation, sugars contained in the concentrated juice are transformed to ethyl alcohol, carbon dioxide ($CO_2$), and various secondary products. Secondary products include other alcohols, aldehydes, glycerin, etc. The alcohol concentration in the clean beer is generally 8 percent.

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

The ferment is continuously transferred from the pre-fermenter to the first fermenter based on level. There are a total of four agitated fermenters in series, each having controlled temperature and controlled additions of urea and yeast to maintain optimum fermentation conditions. Flow is maintained from one fermenter to another based on level.

The product of fermentation, called "beer", has a weak ethanol solution along with the residue of fermentation components. The beer is pumped to a holding tank, designated as the beer well.

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

### 2.2.6 Distillation

In distillation, the filtered beer from fermentation, with an alcohol concentration of approximately 8 percent by weight, is distilled to approximately 96-percent hydrated alcohol.

The beer may contain many other liquid, solid, and gaseous components. Liquid components include water at 89 to 93 percent and finer alcohols, acetic aldehyde, succinic acid, acetic acid, furfural, etc., at lower concentrations. Solid substances include yeast, bacteria, non-fermentable solids, mineral salts, albuminoidal substances, and other miscellaneous substances. Dissolved gases include $CO_2$ and $SO_2$.

From the beer storage, the beer is sent to a pre-heater and then to a beer/stillage heat exchanger. A degassing column removes most of the dissolved gas prior to the beer column. The gas removed in the degassing column is cooled, scrubbed in the distillation scrubber, and then released to atmosphere. The beer column overhead is transferred in the vapor phase to the rectifier column.

The alcohol stream is increased to 91 percent by weight ethanol concentration in the rectifier column. Rectifier overhead vapor is sent to the molecular sieve units to further remove water to less than 0.7 percent by weight in the ethanol product. Propanol and fusel oils are removed from the lower section of the rectifier column and combined with the 91-percent ethanol vapor which goes to the molecular sieves. Rectifier bottoms are sent to a stripper column to strip remaining traces of ethanol from the rectifier bottoms. The bottoms from the stripper column are comprised of almost pure water, and are reused in the process. The stripper column overhead vapor is sent back to the rectifying column.

### 2.2.7 Vinasse Evaporation

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

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

### 2.2.8 Dehydration

The final stage in the ethanol production process is dehydration. Hydrated alcohol from the distillation process, at about 96 percent by volume alcohol, undergoes dehydration with a molecular sieve to produce ethanol at 99.3 percent by weight purity. The process is performed in a continuous operation where the hydrated alcohol is superheated by steam in a shell and tube heat exchanger to ensure that the ethanol stream is always in the vapor phase as it passes through molecular sieve zeolite beds. The pore size of the zeolite allows the smaller water molecules to be adsorbed, while allowing the larger ethanol molecules to pass through the zeolite bed. The final ethanol product is condensed, cooled, and sent to the 200-proof storage tank.

The zeolite beds must be regenerated periodically by vacuum. The molecular sieve bed being regenerated is first isolated from the incoming hydrated ethanol steam and the inlet of this bed is valved to a regeneration condenser. A purge stream consisting of a portion of the dehydrated product from the on-line molecular sieve is fed into the outlet of the regenerating molecular sieve. The non-condensable vapors from the regeneration condenser are removed via a two-stage steam ejector or a liquid ring vacuum pump. The cooled non-condensable vapors are then fed to the distillation vent scrubber. The condensed liquid from the regeneration condenser is reclaimed by sending it back to the rectifier column.

## 2.3 Biomass Boiler

### *2.3.1 Biomass Boiler Design Data*

The biomass boiler will have a maximum operating schedule of 335 days per year [8,040 hours per year (hr/yr)]. The remaining days of the year will be used to perform annual maintenance on the boiler and power block.

The capacity of the biomass boiler will be 462 million British thermal units per hour (MMBtu/hr) and 250,000 lb/hr of steam, based on a 24-hour average. One steam turbine generator will be utilized to generate up to 30 MW (gross) of electricity [up to 20 MW (net) for sale to the grid]. A flow diagram of the proposed process/boiler configuration is shown in Figure 2-5.

The boiler will be designed to burn bagasse and wood primarily in suspension, with some of the combustion occurring on the grate (categorized as a "hybrid suspension/grate" boiler). The grate will be the vibrating grate type. Grate ash falls into bins below the grate and are removed to the ash silo along with ash collected from the mechanical cyclone collector and the electrostatic precipitator. Due to the nature of the high moisture bagasse fuel, some bagasse may fall onto the grate during normal operation and complete combustion on the grate. The bagasse fuel is inextricably tied to the ethanol production process. As in a sugarcane mill, bagasse is sent to the boiler directly from the process. Thus, fluctuations in the ethanol process will directly affect the boiler operation. Variables that affect bagasse fuel quality include the quality of the incoming sugarcane and sweet sorghum feedstock (which is affected by weather conditions, rain, season of the year, etc.), diffuser operation, and drying mill operation.

These aspects of operation make bagasse boilers unique, and emissions from bagasse boilers are unique from other biomass boilers. The EPA has recently recognized the uniqueness of bagasse boilers by establishing a separate subcategory for hybrid suspension/grate-fired boilers under the recently promulgated Industrial Boiler MACT regulations (40 CFR 63, Subpart DDDDD). The proposed HEF bagasse boiler will be of this type.

The hybrid suspension/grate boiler design represents proven technology for bagasse boilers. Most bagasse boilers are of this type, and the newest bagasse boilers in the U.S. [U.S. Sugar Clewiston Boiler Nos. 7 and 8, and Rio Grande Valley Sugar Growers (RGVSG) Boiler No. 5] are all of this design. Other bagasse boiler designs in use today such as fuel cell boilers are inferior to the hybrid suspension/grate design in terms of air emissions. Fluidized bed boiler technology, although possibly attractive from an air emissions standpoint, has never been applied to a bagasse boiler, and therefore is not a proven technology for bagasse.

The boiler will combust bagasse from the juice extraction process. At limited times when sugarcane or sweet sorghum is not being received at the facility for ethanol production, and excess bagasse is not available from the bagasse storage area, wood will be used to continue to operate the boiler to supply steam to the process and electricity to the grid. Natural gas will be used as a startup/supplemental fuel.

Fuel characteristics are presented in Table 2-1. Available data for sugarcane bagasse, raw sorghum, and washed sorghum (similar to sorghum bagasse), including proximate/ultimate analysis, metals content, and ash characteristics, are summarized in Table 2-1. Detailed data are presented in Appendix A.

The design combustion efficiency for the boiler is a minimum 68 percent when burning either bagasse or wood, which will be the normal operating mode. For natural gas, the design efficiency is 82 percent. The boiler furnace will be complete with:

- Biomass fuel feeders
- A high-performance OFA system that includes:
  - Air headers
  - Air nozzles
  - Dampers
  - An OFA fan
- Soot blowers
- A forced draft (FD) fan
- An induced draft (ID) fan
- Pneumatic distribution air fans
- Vibrating grate for ash removal

The boiler will have a superheater, air heater, and economizer. LNBs will be utilized for the natural gas firing.

Plan and elevation views of the boiler are presented in Figures 2-6 and 2-7, respectively.

During normal operation, bagasse will be sent to the boiler directly from the juice extraction process. Based on maximum permitted operation of the boiler, and the amount of bagasse utilized, the expected fuel mix on an annual basis will be approximately 50-percent sugarcane bagasse and 50-percent sorghum bagasse. Wood will be used as fuel only in the event there is an unusual circumstance, i.e., a shortfall in bagasse due to lower fiber content of sugarcane or sorghum, interruption in the bagasse supply, etc. Up to 10 percent wood on an annual basis is provided for in this application as a contingency. The boiler will be designed to burn any biomass fuels independently (i.e., 100-percent bagasse or 100-percent wood), or in combination.

Wood will be received from local suppliers. Some of the wood received at the HEF facility may be classified as yard waste or yard trash under definitions in the federal New Source Performance Standards (NSPS). To ensure that the boiler does not become applicable to the NSPS for municipal waste combustors (MWCs), combustion of yard trash will be limited to 10 percent by weight on a calendar quarter basis (see Subsection 3.5.1 for further description).

The natural gas will be secured from an adjacent natural gas pipeline. Although the intent of HEF is to burn 100-percent bagasse from the ethanol process, the boiler will be permitted to burn up to 30 percent natural gas on an annual heat input basis in the event there is an interruption in the bagasse supply. Actual annual natural gas firing is expected to be less than 5 percent on a heat input basis.

Design parameters for the proposed biomass boiler are presented in Table 2-2. The maximum heat input rates and fuel usage rates for the proposed boiler are shown in Table 2-3. The maximum 3-hour average heat input to the biomass boiler will be 504 MMBtu/hr for combusting biomass, and 249 MMBtu/hr for burning natural gas. The maximum 3-hour average steam production rate will be 275,000 lb/hr. The maximum 24-hour average heat input will be 458.5 MMBtu/hr for combusting biomass, corresponding to a maximum 24-hour average steam production rate of 250,000 lb/hr. The derivation of the maximum short-term heat input rates for the biomass boiler are provided in Appendix A.

The biomass boiler will use SNCR and a modern OFA system for minimizing emissions of $NO_x$. LNBs will be utilized for firing natural gas. A wet sand separator (cyclone) and an ESP will be used for control of PM and metals emissions. The very low sulfur content of the fuels utilized and a DSI system will control emissions of $SO_2$ and other acid gases, including HCl. The clean biomass fuel will control emissions of Hg and other metals. The modern OFA system will control emissions of CO and VOC. An oxygen monitor will be used for combustion control (refer to further description in Section 2.9). Additional information concerning the air pollution control equipment for the boiler is provided in Section 5.0, Best Available Control Technology Analysis, and in the application form.

The boiler will include a sootblowing system to effectively remove ash from the stoker grate and to clean the boiler and steam tube surfaces. It is anticipated that the sootblowers will be used once every 8-hour shift. The duration of sootblowing will be approximately 30 to 45 minutes. It is anticipated that opacity and particulate emissions will increase during the operation of the sootblowers. Although it is not possible to quantify the magnitude of emissions during sootblowing, HEF is requesting a higher opacity limit for sootblowing periods, not to exceed 3 hours per day (see Section 2.14).

The biomass boiler will be constructed with an integral ash removal system. Ash will consist of boiler bottom ash (ash removed from the grate), dust collector ash (ash removed by the mechanical dust collectors), and fly ash (ash removed by the ESP). Bottom ash will be dropped onto a submerged drag conveyor and conveyed to a floor drain to be pumped to an ash settling pond. All other ash will be conveyed from these sources to the ash silo. From the ash silo, the ash will be loaded into trucks and sent offsite.

The biomass boiler will be subject to federal NSPS, 40 CFR 60, Subpart Db for Industrial Boilers. The boiler will meet all requirements of the NSPS.

### 2.3.2 Biomass Handling System

A biomass fuel feed system for the boiler will be used to convey bagasse from the ethanol process and excess bagasse and/or wood from the biomass storage area to the boiler. A flow diagram of the proposed system is presented in Figure 2-8.

During ethanol processing, bagasse is normally conveyed from the bagasse drying system directly to the boiler by means of a conveyor belt. The bagasse will be gravity fed from the conveyor to the fuel feeders. The feeders feed bagasse into the lower part of the furnace via pneumatic air distributors. Excess bagasse (overfeed) not entering the boiler is conveyed to the bagasse storage area where it can later be reclaimed via front-end loader to the reclaim conveyor. From the reclaim conveyor, bagasse will be transferred to the return conveyor and then to the bagasse transfer conveyor, which conveys the bagasse to the boiler.

Sugarcane, sweet sorghum, and wood will be brought to the HEF facility by truck. Wood will be stored in the biomass storage area. Wood will be transferred onto the reclaim conveyor via front-end loader. Because wood can be fired independently of bagasse, the same conveyor system used for bagasse will be used for wood. From the reclaim conveyor, the wood will be transferred to the return conveyor and to the bagasse transfer conveyor, and then sent to the boiler. The wood chips will be gravity fed from the conveyor to the fuel feeders (same as for bagasse). The feeders will feed the wood chips into the lower part of the furnace via pneumatic air distributors. Excess wood chips (overfeed) not entering the boilers will be conveyed back to the wood storage area via the surplus bagasse conveyor and reintroduced into the reclaim system.

## 2.4 Cooling Towers

The proposed HEF facility will have as many as three mechanical draft cooling towers. Cooling water will be utilized for the turbine generator condenser, various equipment cooling systems, process condensers, and a chiller system utilized for the fermentation process. Depending on location and required cooling water characteristics, all three services may be combined into one cooling tower which would require a capacity of approximately 34,000 gallons per minute (gpm) of cooling water at 85 degrees Fahrenheit (°F). Cooling tower make up will be primarily a suitable recycled process water stream. Cooling tower blowdown will be treated to remove accumulated dissolved solids and then reused for cooling tower makeup.

## 2.5 Tanks

The facility will contain several volatile organic liquid storage tanks for ethanol, denaturant/gasoline, and corrosion inhibitor. Up to 1 million gallons of fuel ethanol will be stored. A list of the tanks containing organic liquids and tank parameters, including tank throughputs, is presented in Table 2-4. The tanks will be internal floating roof design, except for the small corrosion inhibitor storage tank.

Several of the tanks will be subject to federal NSPS, 40 CFR 60, Subpart Kb. The NSPS tanks are as follows:

- Fuel Ethanol Storage Tank: 1,000,000 gallon capacity
- 200 Proof Ethanol Storage Tank: 100,000 gallon capacity
- Off-Spec Tank: 100,000 gallon capacity
- Denaturant/Gasoline Tank: 100,000 gallon capacity

Subpart Kb requires the subject tanks to have internal floating roofs, external floating roofs, or an equivalent control system. HEF is proposing to use fixed roof tanks in combination with internal floating roofs to meet the NSPS. The NSPS requires the following design requirements for fixed roof tanks fitted with internal floating roofs:

> (i) The internal floating roof shall rest or float on the liquid surface (but not necessarily in complete contact with it) inside a storage vessel that has a fixed roof. The internal floating roof shall be floating on the liquid surface at all times, except during initial fill and during those intervals when the storage vessel is completely emptied or subsequently emptied and refilled. When the roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible.
>
> (ii) Each internal floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the internal floating roof:
>
>> (A) A foam- or liquid-filled seal mounted in contact with the liquid (liquid-mounted seal). A liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the storage vessel and the floating roof continuously around the circumference of the tank.

(B) Two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage vessel and the edge of the internal floating roof. The lower seal may be vapor-mounted, but both must be continuous.

(C) A mechanical shoe seal. A mechanical shoe seal is a metal sheet held vertically against the wall of the storage vessel by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

(iii) Each opening in a noncontact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and the rim space vents is to provide a projection below the liquid surface.

(iv) Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains is to be equipped with a cover or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted except when they are in use.

(v) Automatic bleeder vents shall be equipped with a gasket and are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

(vi) Rim space vents shall be equipped with a gasket and are to be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting.

(vii) Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The sample well shall have a slit fabric cover that covers at least 90 percent of the opening.

(viii) Each penetration of the internal floating roof that allows for passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover.

(ix) Each penetration of the internal floating roof that allows for passage of a ladder shall have a gasketed sliding cover.

## 2.6 Truck/Rail Loadout and Flare

Loading racks will be used to load out denatured fuel ethanol from the product storage tank to trucks and railcars. In-line blending for gasoline and ethanol to produce E-85 may also take place at the loading rack. One loading rack will be provided for trucks, and one for railcars. The maximum truck loading rate of each rack will be 600 gpm. During ethanol loadout, ethanol and gasoline vapors can be generated. The vapors are sent to the loading racks flare for destruction. The loading racks and the flare will be permitted to operate up to 3,120 hr/yr.

## 2.7 Emergency Engines

HEF may install one diesel- or natural gas-fired electric generator of 2,000-kilowatt (kW) capacity, for purposes of supplying electric power to the facility in the event of a black start or power failure. In addition, an emergency diesel/natural gas-fired fire pump will be installed to provide fire water in the event of a power failure during an emergency situation. The fire pump will be of 600 brake horsepower (bhp) capacity. The emergency engines will meet all requirements of NSPS, 40 CFR 60, Subpart IIII, *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*.

## 2.8 Materials Storage Silos

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

## 2.9 Air Pollution Control Equipment

### *2.9.1 Ethanol Production Process*

Two wet scrubbers will be used in the ethanol production area to control emissions of ethanol/VOC. The scrubbers will control emissions from the following processes:

- Fermentation
- Distillation
- Dehydration

One wet scrubber will control air emissions from the fermentation tanks, while the second will control air emissions from the distillation columns and associated condensers, and the molecular sieves and vacuum pump in the dehydration area. Scrubber parameters are shown in Table 2-5. The wet scrubbers will use water as the scrubbing liquid to maximize ethanol removal in the scrubbers. The fermentation wet scrubber will have an ethanol/VOC removal efficiency of 98 percent, and the distillation/dehydration scrubber will have a ethanol/VOC removal efficiency of 98 percent.

### *2.9.2 Biomass Boiler*

As previously described, a dust separator (cyclone) and an ESP will be used for control of PM and metals emissions. The manufacturers of the mechanical dust collectors and ESP have not yet been selected, so specific design information is not yet available. However, mechanical collector and ESP specifications for one potential vendor meeting HEF requirements are shown in Tables 2-6 and 2-7, respectively.

The biomass boiler will use SNCR and a modern OFA system for minimizing emissions of $NO_x$. LNBs will be utilized for firing natural gas. The manufacturer of the SNCR system has not yet been selected, so specific design information is not available. SNCR system specifications for one potential vendor meeting HEF requirements are shown in Table 2-8.

The very low sulfur content of the fuels utilized and a DSI system will control emissions of $SO_2$ and other acid gases, including HCl. The DSI system will inject a dry sorbent (i.e., sodium bicarbonate or proprietary chemical) into the ductwork between the boiler and the cyclone. The manufacturer of the DSI system has not yet been selected, so specific design information is not available. DSI system specifications for one potential vendor meeting HEF requirements are shown in Table 2-9.

Additional vendor data is provided in Appendix J.

The clean biomass fuel and ESP will control emissions of Hg and other metals. The modern OFA system will control emissions of CO and VOC. An oxygen monitor will be used for combustion control.

In addition to these add-on control technologies, the biomass boiler will employ good combustion practices (GCPs). The fuel-air ratio will be controlled by adjusting the primary (undergrate) air. The master pressure controller output signal will pass through a predefined ratio station, which then becomes the set point for the air flow controllers. The air flow signal is then trimmed by the oxygen controller, which trims the air flow to a predetermined oxygen level.

The oxygen content of the flue gas will be measured in the boiler outlet duct prior to the air heater to ensure that the flue gas reading is not affected by dilution from tramp air. The set point of the oxygen controller will vary with load and fuel quality. The operator will also be able to manually adjust the air flow to address situations where the fuel may be very wet, to maintain steam rate, maintain proper combustion conditions, and control CO and opacity.

The normal operating range of the flue gas oxygen will be dependent upon boiler load, the quality of the fuel, and the type of fuel:

- Under normal operating conditions, the boiler exit oxygen ($O_2$) is expected to be between 3 and 4 percent. High fuel moisture, high ash content, and low-load conditions could result in the boiler exit $O_2$ increasing to 5 to 6 percent.
- The boiler exit $O_2$ while firing only fuel oil or propane will range between 8 and 9 percent. This is because of the tramp air required for cooling of the stoker or for bed air, pneumatic distributors, and OFA nozzles during fuel oil or propane firing.
- The stack $O_2$ for both cases could be 1 to 2 percent higher depending on the amount of ambient air infiltration there is across the system.

The proposed GCPs for the biomass boiler are provided below:

> An oxygen meter shall be installed to continuously monitor a representative sample of the flue gas. The oxygen monitor shall be used with automatic feedback or manual controls to continuously optimize air/fuel ratio parameters. Depending on the fuel quality and existing combustion conditions, the operator shall provide sufficient excess air to ensure good combustion within the boiler. The application for a Title V operation permit shall identify GCPs for the biomass boiler to minimize pollutant emissions during startup, operation, and shutdown. The document *Use of Flue Gas Oxygen Meter as BACT for Combustion Controls* shall be used as a guide. Good combustion controls shall also include the following:
>
> - Maintain improved combustion controls to provide efficient tuning of air/fuel control instrumentation
> - Maintain rotary pocket-style biomass feeders with efficient air seal to minimize intrusion of ambient air

- Maintain effective water level controls in bottom ash system to prevent intrusion of ambient air
- Mix biomass fuel to provide a consistent fuel blend
- Maintain the flue gas oxygen content to provide efficient combustion for the existing conditions
- When necessary to enhance poor combustion, reduce the biomass feed rate below the maximum rate
- When necessary to enhance poor combustion, co-fire natural gas

### 2.9.3 Tanks

The tanks that are subject to Subpart Kb will be fitted with internal floating roofs for control of VOC emissions.

### 2.9.4 Ethanol/Ethanol Blends Truck/Rail Loadout

Off-gases from the ethanol/gasoline truck/rail loadout rack will be controlled by routing the vapors to a flare. The flare will be of the open type.

### 2.9.5 Materials Storage Silos

The storage silos will each have a standard type bin vent filter to control dust emissions. These are passive control devices that do not have a fan. When the silos are pneumatically loaded from trucks, the conveying air must exit the silo through the bin vent filter.

### 2.9.6 Truck Traffic

Fugitive dust emissions from truck traffic will be controlled by utilizing paved roads and by performing sweeping with a street sweeper or watering as needed.

## 2.10 Air Emissions

### 2.10.1 Ethanol Production Process

Air emissions from the ethanol production process will come from the two wet scrubbers serving the process. Emissions will consist of $CO_2$, ethanol, and minor VOC constituents.

Emissions from the fermentation wet scrubber and the distillation and dehydration wet scrubber are based on uncontrolled emission estimates developed by Vogelbusch, the designer of the ethanol process equipment, and the scrubbers' efficiency of 98 and 98 percent, respectively. The estimated emissions are presented in Tables 2-10 and 2-11. Total VOC emissions from the two wet scrubbers are approximately 80 TPY.

### 2.10.2 Biomass Boiler

The maximum short-term emissions for the biomass boiler for each fuel type (bagasse, wood, and natural gas) are presented in Table 2-12. The maximum short-term emissions for each fuel burned alone are shown.

Emissions of PM/$PM_{10}$ are based on a proposed BACT limit of 0.015 pound per million British thermal units (lb/MMBtu) of heat input to the boiler. This limit is equal to the recently promulgated Industrial Boiler MACT limit for PM for solid fuel boilers. This limit will be achieved by the ESP on a continuous basis. Emissions of $PM_{2.5}$ are estimated from EPA Publication AP-42, which states that $PM_{2.5}$ emissions are 65 percent of $PM_{10}$ emissions for wood-fired boilers equipped with an ESP.

Uncontrolled $SO_2$ emissions from bagasse/wood firing are a function of the sulfur content of the biomass. Biomass fuels have very low sulfur content. In addition, wood-fired and bagasse-fired boilers have demonstrated that $SO_2$ is absorbed into the alkaline fly ash produced from biomass combustion. The absorption takes place downstream of the boiler, in the ductwork, mechanical collectors, and ESP. In addition, a DSI add-on control system for $SO_2$ and HCl emissions is proposed for the biomass boiler.

The $SO_2$ emission rates for the boiler for sugarcane bagasse, sorghum bagasse, and wood are based on an uncontrolled emission rate of 0.31, 0.56, and 0.30 lb/MMBtu, respectively, and 75-percent removal efficiency. The DSI system is adequate to reduce emissions to these levels on a short-term basis.

Maximum $SO_2$ emissions for natural gas firing are based on AP-42 emission factor. The DSI system will be employed as necessary when burning biomass (75-percent $SO_2$ control), but is not needed when solely firing natural gas. As shown in Table 2-12, the maximum $SO_2$ emissions occur while burning biomass.

Maximum 1-hour and 3-hour $NO_x$ emissions from the biomass boiler are based on uncontrolled emissions with the SNCR system off. The maximum emission factor is 0.25 lb/MMBtu for bagasse and wood, and 0.20 lb/MMBtu for natural gas. Although the maximum short-term emissions are reflective of uncontrolled $NO_x$ emissions, this condition will occur very infrequently. The boiler and SNCR control system will normally be operated to achieve 0.10 lb/MMBtu, which is the proposed 30-day rolling average $NO_x$ limit.

Emissions of CO and VOC are a function of the fuels burned as well as implementation of GCPs. For CO, due to the nature of the biomass fuel and accounting for potential boiler startup conditions, the maximum emissions for biomass firing are based on 3.0 lb/MMBtu. The 30-day rolling average CO emission limit is based on the proposed BACT limit of 0.30 lb/MMBtu, equivalent to approximately 400 parts per million by volume dry (ppmvd) at 3-percent $O_2$. This limit excludes startup, shutdown, and malfunction conditions. A second limit of 552.9 TPY is proposed, which includes startup, shutdown, and malfunction events (equivalent to 0.30 lb/MMBtu, 458 MMBtu/hr, and 8,040 hr/yr operation). These limits are much lower than the recently promulgated Industrial Boiler MACT limit for new hybrid suspension/grate boilers located at major sources of HAPs, and also less than the Industrial Boiler MACT regulation for area (non-major) sources of 1,500 ppmvd @ 3 percent $O_2$, 30-day rolling average.

For VOC, the proposed limit is 0.017 lb/MMBtu for bagasse and wood. Maximum CO and VOC emissions from natural gas combustion are based on AP-42 factors.

Hg emissions are a function of the Hg content of the fuels burned. Therefore, maximum uncontrolled emissions for Hg are based on the maximum tested Hg content from sugarcane bagasse and raw sweet sorghum analysis. Hg emissions from wood fuels are based on New Hope Power Company (NHPC) testing for sugarcane bagasse and wood, based on stack test results from three similar boilers at NHPC. The uncontrolled Hg emission rate for bagasse is therefore $1.38 \times 10^{-5}$ lb/MMBtu. The Hg emission rate for wood is $3.6 \times 10^{-6}$ lb/MMBtu. The Hg test data from NHPC is presented in Appendix B.

In order to ensure that these Hg emissions are met, HEF will make provisions for a carbon injection system; however, the system will not be installed unless stack testing indicate that the proposed emission rates cannot be met.

Emissions of Pb and fluorides from the biomass boiler are also a function of the fuels. NHPC was required to perform stack testing for fluorides while burning either sugarcane bagasse or wood in Boilers A, B, and C until the year 2001. Based on the NHPC stack test results (see Appendix B), the maximum tested fluoride emission rate in lb/MMBtu for either bagasse or wood was selected as the emission factor for the proposed biomass boiler: $6.0 \times 10^{-4}$ lb/MMBtu. For Pb, based on fuel analysis of sugarcane bagasse and raw sweet sorghum, an emission factor of $9.6 \times 10^{-5}$ lb/MMBtu was used for bagasse. For wood, an emission factor based on NHPC test results for Boilers A, B, and C was used: $8.4 \times 10^{-5}$ lb/MMBtu.

Emissions of SAM are a function of $SO_2$ emissions. The maximum short-term emissions are based on a factor of 4 percent of $SO_2$ emissions becoming sulfur trioxide ($SO_3$) from fuel oil burning sources (AP-42) and then converting $SO_3$ to sulfuric acid ($H_2SO_4$) based on molecular weights.

The maximum annual average emissions for the biomass boiler were based on the worst-case fuel mix for each pollutant. For all pollutants, burning bagasse or wood was the worst case. For this scenario, the maximum sorghum burning with the remainder due to wood was assumed.

Emissions factors used to estimate the maximum annual emissions were based on the same emission factors used for the short-term emission rates shown in Table 2-12. The maximum annual emissions are presented in Table 2-13. The maximum annual emissions for any fuel scenario are indicated in the far right-hand column of the table.

The biomass boiler will be subject to the NSPS for Industrial Boilers, contained in 40 CFR 60, Subpart Db. The proposed boiler will meet all emission limits imposed by the NSPS (see Section 3.5 for further discussion).

Emissions of HAPs have been estimated for the proposed boiler and are shown in Tables 2-14 and 2-15 and in Appendix B. Emission factors for sugarcane bagasse and wood firing are based on test data from Boiler Nos. 7 and 8 at the U.S. Sugar Clewiston facility, and NHPC's Boilers A, B, and C (refer to Appendix B). Historic test data are available for Pb, Hg, and HCl from NHPC's Boilers A, B, and C. Data on HCl, chlorine, and other HAPs, including organics, is available from Boiler Nos. 7 and 8 at U.S. Sugar. Available fuel testing data is presented in Appendix A.

For sorghum bagasse, the design chlorine content of the sorghum (0.24 percent, dry basis, or 0.32 lb/MMBtu as HCl) was assumed along with a 25 percent inherent removal in the ash. The fly ash from biomass combustion is highly alkaline and nature and acts to absorb HCl and other acid gases in the flue gas stream. The resulting HCl emission factor for sorghum bagasse firing is 0.08 lb/MMBtu. The DSI system will also act to maintain HCl emission at or below this level. Metals data reported by Southeast Renewable Fuels was used to estimate metals emission rates due to sorghum bagasse burning.

For wood firing, AP-42 factors for HAPs emissions were utilized, except for pollutants for which test data were available from U.S. Sugar or NHPC (see Appendix B). For natural gas, AP-42 factors for natural gas were used and converted to lb/MMBtu values based on the heating value of the fuels.

The resulting maximum total HAPs emissions from the proposed boiler are 18.3 TPY (Table 2-15). Refer to Appendix E for AP-42 emission factor documentation.

### *2.10.3 Biomass/Ash Materials Handling System*

The potential annual fugitive PM emissions from the proposed biomass and ash handling systems for the biomass boiler were developed. As a worst-case scenario, 90-percent biomass handling is assumed for bagasse, and 10-percent biomass handling is assumed for wood. For this scenario, the maximum amount of biomass burned in the boiler is estimated at 468,708 TPY. For the biomass handling system, an additional 10 percent processed was added to account for year-to-year variability in biomass fuel handled, resulting in 515,579 TPY biomass.

No PM emissions are expected from handling the sugarcane and sweet sorghum feedstock, as this biomass is approximately 70 to 80 percent moisture. The biomass handling system will include conveyors, a screen and hogger for wood processing, a bagasse storage pile, a wood storage pile, a biomass reclaim system, etc.

The maximum annual fugitive emissions based on the maximum biomass usage and ash handling for the biomass boiler is shown in Table 2-16. This includes fugitive emissions due to material handling, wind erosion of storage piles, and vehicular traffic for storage pile maintenance. Emission factors are based primarily on EPA AP-42 emission factors for material drop operations, heavy equipment operations, and vehicular traffic over paved roads (refer to Appendix E). The moisture content of bagasse and wood was based on typical moisture content of these materials.

HEF will employ several fugitive dust control techniques, including the inherent moisture content of wood and bagasse fuels, watering of storage piles, and watering of haul roads. Control efficiencies for these measures were based on published data.

Refer to Appendix C, Tables C-1 through C-5, for more detailed information on the fugitive dust calculations, equations used, and reference materials. As shown in Table 2-16, the maximum estimated fugitive PM emissions from the bagasse, wood, and ash handling systems and truck traffic are 7.9 TPY, while maximum $PM_{10}$ emissions are 1.8 TPY, and maximum $PM_{2.5}$ emissions are 0.33 TPY. Refer to Subsection 2.10.9 for a description of truck traffic emissions.

### *2.10.4 Cooling Towers*

The HEF Facility will have up to three cooling towers for machine cooling, cooling the condensing set, and process cooling. PM emissions due to cooling tower drift, based on a drift rate of 0.001 percent and a total dissolved solids (TDS) concentration of 500 ppm, reflecting typical values for freshwater in the vicinity of the site, are shown in Table 2-17. It was conservatively estimated that $PM_{10}$ and $PM_{2.5}$ make up 50 percent of PM drift.

### *2.10.5 Tanks*

Three metering tanks and five (5) storage tanks will be used for ethanol, second-grade alcohol, fusel oil, and denaturant/gasoline. VOC and HAP emissions were estimated from each of the tanks using EPA's TANKS 4.0.9d (TANKS) program. Details are shown in Tables D-1 through D-3 in Appendix D, including tank parameters, product throughput, and emissions estimates. The output from the TANKS program is also presented in Appendix D.

### *2.10.6 Truck/Rail Loadout Flare*

As discussed in Section 2.7, the truck/rail loadout flare will be permitted to operate up to 3,120 hr/yr. The maximum amount of fuel loaded out will be 36,000,000 gal/yr of ethanol plus 1,620,000 gal/yr of denaturant/gasoline (4.5 percent of ethanol). Based on the loadout rate of 600 gpm, the flare would operate only 1,045 hr/yr, while being on pilot the remaining time. However, the truck loadout rate may be less than 600 gpm. Short-term and annual emission calculations, based on AP-42 emission factors for industrial flares (Section 13.5), are shown in Table 2-18. HAPs emissions estimates are presented in Table 2-19.

### 2.10.7 Emergency Engines

The emergency electrical generator will meet all requirements of 40 CFR 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. Section 60.4205(b) of the NSPS limits emissions from new emergency compression ignition internal combustion engines (CI ICE) to the standards applicable to new non-road engines in Section 60.4202. The emergency generator will have a displacement of less than 10 liters per cylinder, and therefore Section 60.4202(a)(2) would apply. This section requires that the engines meet the emission limits specified in 40 CFR 89, Sections 89.112 and 89.113. The emission limits specified in Section 89.112 are as follows (Tier 2 for model year 2006 and later):

Non-methane hydrocarbon (NMHC) + $NO_x$ = 6.4 grams per kilowatt-hour (g/kW-hr)
CO = 3.5 g/kW-hr
PM = 0.20 g/kW-hr

Section 89.113 sets opacity limits for the engines.

Emissions for the electrical generator were calculated based on the manufacturer's data for 100-percent load operation (nominal emissions; see Appendix F). These differ from the NSPS emission standards, which are based on a "weighted cycle" operation. The manufacturer's 100-percent load emission factors and resulting air emissions are shown in Table 2-20. HAPs emissions are presented in Table 2-21.

The emergency fire pump engine will also meet all requirements of 40 CFR 60, Subpart IIII. Section 60.4205(c) of the NSPS limits emissions from new fire pump engines with a displacement of less than 30 liters per cylinder to the standards in Table 4 of Subpart IIII. Based on a 600-bhp fire pump engine, the emission limits specified in Table 4 are as follows (for model year 2009 and later):

NMHC + $NO_x$ = 3.0 g/kW-hr
CO = 2.6 g/kW-hr
PM = 0.15 g/kW-hr

Emissions for the fire pump engine were calculated based on the NSPS limits, since no specific manufacturer's data was available (see Appendix F). The resulting air emissions are shown in Table 2-22. HAPs emissions estimates are presented in Table 2-23.

### 2.10.8 Materials Storage Silos

Air emissions from the DSI reagent storage silos were based on a nominal bin vent filter flow rate of 2,458 dry standard cubic feet per minute (dscfm) and an outlet grain loading of 0.01 grain per dry standard cubic foot (gr/dscf). Annual emissions were based on the estimated material unloading times for each silo. Emission calculations are shown in Table 2-24.

### 2.10.9 Truck Traffic

A number of activities will create truck traffic within the HEF site. This will include the sweet sorghum and sugar cane delivered to the HEF site to accommodate the biomass boiler, any wood fuel delivered, ash produced from the biomass boiler, ethanol and ethanol blends loaded out from the truck rack, fusel oil and second grade alcohol loadout, and gasoline deliveries. This traffic will travel over paved roads within the HEF site.

The estimated truck traffic is shown in Table 2-25. It is also assumed that all ash generated by the boiler (bottom ash and fly ash) will be transported off site, and not disposed on site.

Fugitive dust emissions associated with this traffic were estimated. The maximum annual fugitive PM emissions due to truck traffic are presented in Table C-4 in Appendix C. Emission factors were based on EPA AP-42 factors for paved roads. Road silt content was assumed as 1.1 grams per square meter ($g/m^2$), based on the results of a sampling at a similar site. Estimated truck emissions are included in the total fugitive emissions estimates for the material handling system, shown in Table 2-16.

### 2.10.10 Fugitive VOC Emissions from Equipment Leaks

Fugitive VOC emissions from equipment leaks in the ethanol production process have been estimated and are presented in Table 2-26. Emissions have been estimated based on the document entitled "Protocol for Estimating Equipment Leaks" (EPA, 1995). The number of pumps, valves, flanges, and connectors has been estimated for the ethanol process, as well as the number in gas, light liquid, and heavy liquid service. VOC control efficiencies based on a leak detection and repair (LDAR) program have been included. As shown, the total fugitive VOC emissions are estimated to be 6.52. Emission units associated with ethanol projects are subject to NSPS Subpart VVa – Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemical Manufacturing Industry. A requirement of Subpart VVa is the development of a LDAR program for the control of VOC emissions. A preliminary LDAR program describing the reasonable precautions to control fugitive VOC emissions is presented in Appendix G.

## 2.11 Total Facility Emissions

### 2.11.1 Criteria Pollutant and HAP Emissions

Total HEF Facility emissions are shown in Table 2-27 (criteria pollutants) and in Table 2-28 (HAPs). As shown, HEF will be a major source of air emissions (i.e., criteria pollutant greater than 100 TPY), but a minor source of HAPs (i.e., individual HAPs < 10 TPY, and total HAPs < 25 TPY).

### 2.11.2 HEF Greenhouse Gas Emissions

Estimates of potential GHG emissions for the proposed HEF facility are presented in Table 2-29. The potential GHGs for the facility are approximately 534,000 TPY of carbon dioxide equivalents ($CO_2e$).

Non-biogenic GHG emissions are only a small fraction of the total $CO_2e$ emitted from the facility, i.e., 10,451 TPY $CO_2e$. The GHGs emitted by the facility consist of $CO_2$, nitrous oxide ($N_2O$), and methane ($CH_4$). There are several potential stationary sources of GHG emissions associated with the HEF facility. These include the following:

- Biomass Boiler
- Ethanol production process
- Truck/rail loadout flare
- Emergency electric generator
- Emergency fire pump

The derivation of these GHG emissions is described in the following sections.

***Biomass Boiler***

GHG emissions from the biomass boiler result from burning biomass (sugarcane bagasse and sweet sorghum bagasse) in the boiler to generate steam. Based on the boiler design, up to 30 percent of the heat input to the boiler could come from natural gas, but this level of natural gas burning will only be used if there is an interruption to the bagasse and wood supply. However, based on GHG emission factors, the burning of natural gas will produce lower quantities of $CO_2e$ emissions compared to bagasse; therefore, bagasse burning was assumed as the worst case.

$CO_2$ emissions for sugarcane bagasse and sweet sorghum bagasse were based on the approximate carbon content of these fuels (23 percent, wet basis) and the annual fuel usage of each. Emissions of $N_2O$ and $CH_4$ for these fuels were based on default emission factors [in kilograms per million British thermal units (kg/MMBtu)], obtained from EPA's Mandatory GHG Reporting Rule (40 CFR 98), and the annual heat input due to each fuel. $N_2O$ and $CH_4$ emissions were converted to $CO_2e$ by multiplying the emissions of each by their GHG potential (21 for $CH_4$ and 310 for $N_2O$).

As shown in Table 2-29, total GHG emissions from the biomass boiler are estimated to be 398,559 TPY $CO_2$; 17.1 TPY $N_2O$; 130.1 TPY $CH_4$; and 406,582 TPY $CO_2e$. Non-biogenic GHG emissions from the boiler are only 8,023 TPY $CO_2e$.

***Ethanol Production Process***

GHG emissions from the ethanol process result from the conversion of extracted sorghum sugars to ethanol through fermentation and distillation. These processes generate $CO_2$ emissions, primarily from the fermentation step. Emissions of $CO_2$ in lb/hr were based on data from Vogelbusch, the ethanol process manufacturer. Annual emissions were based on 7,296 hr/yr operation (304 days per year). As shown in Table 2-29, $CO_2$ emissions from the ethanol process are estimated to be 124,976 TPY $CO_2$ and

124,976 TPY $CO_2$e. However, all of these emissions are considered to be biogenic in nature, since they are due to natural fermentation.

***Truck/Rail Loadout Flare***

A truck/rail loading rack will be used to loadout ethanol and ethanol/gasoline product. A flare will be used to combust the vapors resulting from the truck loadout and rail loadout operations. Emissions of $CO_2$, $N_2O$, and $CH_4$ for the flare were based on default emission factors (in kg/MMBtu) for petroleum, obtained from EPA's Mandatory GHG Reporting Rule (40 CFR 98), and an assumed annual heat input due to ethanol/gasoline vapors. The flare will utilize natural gas as a pilot fuel. Default emission factors were also used for this fuel. $N_2O$ and $CH_4$ emissions were converted to $CO_2$e by multiplying the emissions of each by their GHG potential.

As shown in Table 2-29, total GHG emissions from the truck/rail loadout flare are estimated to be 2,420 TPY $CO_2$; 0.020 TPY $N_2O$; 0.10 TPY $CH_4$; and 2,429 TPY $CO_2$e.

***Emergency Electric Generator and Fire Pump***

The internal combustion engines used for emergencies were not considered in the GHG emission estimates, since these will only be used in emergencies and for testing purposes.

***Summary***

Total direct GHG emissions from the stationary sources at the HEF facility are shown in Table 2-29, and are estimated to be 525,956 TPY $CO_2$; 17 TPY $N_2O$; 130 TPY $CH_4$; and 533,987 TPY $CO_2$e. Of these total GHG emissions, only 10,451 TPY $CO_2$e are non-biogenic in nature.

## 2.12 Plant Layout

A plot plan of the facility showing the locations of the proposed ethanol production process, biomass boiler, flares, dry ice unit, wastewater treatment equipment, tanks, and air emission points, is presented in Figure 2-2.

## 2.13 Stack Parameters

Stack parameters for all air emission point sources associated with the proposed facility are shown in Table 2-30. Parameters include stack height and diameter, actual volumetric air flow rate, and stack temperature. Refer to Section 6.0 for stack parameters for fugitive dust emission sources.

## 2.14 Excess Emissions

The startup and shutdown of the biomass boiler will require an excess emissions allowance greater than the 2 hours provided under the Florida Department of Environmental Protection (FDEP) rules. Rule 62-210.700, F.A.C., states the following:

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

(2) Excess emissions from existing fossil fuel steam generators resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized.

Based on similar operating boilers (Boilers A, B, and C at NHPC), a startup/shutdown plan which allows more than 2 hours of excess emissions during these periods is provided below. The plan also provides for continuous monitoring data exclusions.

Startup, Shutdown, and Malfunction Requirements: The permittee shall comply with the following requirements regarding periods of startup, shutdown, and malfunction for each cogeneration boiler.

a. *Definitions*

1) Excess emissions are emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions that occur during startup, shutdown, or malfunction. [Rule 62-210.200(106), F.A.C.]

2) Startup is the commencement of operation of a boiler which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical, or pollution control device imbalances, which may result in excess emissions. Periods of startup for each boiler shall end once steam generation reaches 100,000 lb/hr. A cold startup is a startup after the boiler has been shut down for 24 hours or more. A warm startup is a startup after the boiler has been shut down for less than 24 hours.

3) Shutdown is the cessation of the operation of a boiler for any purpose after steam generation drops below 100,000 lb/hr.

4) Malfunction is any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner. [Rule 62-210.200(160), F.A.C.]

b. *Prohibition*: Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited. Emissions data recorded during such preventable periods shall be included in the compliance averages. [Rule 62-210.700(4), F.A.C.]

c. *Monitoring Data Exclusion*: Each continuous monitoring system shall operate and record data during all periods of operation (including startup, shutdown, and malfunction) except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. Provided the operators implement best operational practices to minimize the amount and duration of emissions, the following conditions apply. Pursuant to

Rules 62-210.700(1) and (5), F.A.C., these conditions consider the variations in operation of the cogeneration boilers.

1) Natural gas shall be fired during startup prior to energizing the ESP. Once the operating temperature recommended by the ESP manufacturer is maintained (approximately 340°F to 350°F), it shall be placed on line and the boiler shall comply with the opacity standard. The ESP shall be on line and functioning properly before firing any biomass.

2) Hourly CO and $NO_x$ emission rate values collected during startup, shutdown, or documented malfunction may be excluded from the 30-day and/or 12-month compliance averages.

   *Cold startup*: No more than six hourly emission rate values (CO or $NO_x$) shall be excluded in a 24-hour period.

   *Warm startup*: No more than three hourly emission rate values (CO or $NO_x$) shall be excluded in a 24-hour period.

   *Malfunction*: No more than two hourly emission rate values (CO or $NO_x$) shall be excluded in a 24-hour period.

   *Shutdown*: No more than two hourly emission rate values (CO or $NO_x$) shall be excluded in a 24-hour period.

   For the cogeneration boiler, no more than 183 hourly emission rate values shall be excluded during any calendar quarter.

3) All valid hourly $SO_2$ emission rate values shall be included in all of the compliance averages. Each 1-hour average $SO_2$ emission rate must be based on 30 or more minutes of steam generating unit operation.

## 2.15 Monitoring

Monitoring of steam production, fuel usage rates, air pollutant emissions, and air pollution control device parameters will be performed for the new biomass boiler operation. The bagasse and wood feed rates and the boiler heat input rate will be determined consistent with standard industry practice. It is not practical or accurate to directly weigh the amount of biomass fuel entering the boiler. Therefore, the boiler heat input rate will be determined by continuously measuring steam production rate, steam pressure and temperature, and feedwater temperature, and using this information to calculate the heat input rate.

Heat input rate to the boiler will be determined on an hourly basis. First, using the steam and feedwater enthalpies and steam production rate, the heat content of the steam will be determined. Any heat input to the boiler due to natural gas will then be determined using fuel rate measurements. The design efficiency of 82 percent for natural gas will be used to determine the amount of fossil fuel heat input entering the steam. The remaining heat content of the steam is due to biomass firing. Using the design thermal efficiency of 68 percent for bagasse and wood, the heat input rate due to either bagasse or wood will be determined using the design fuel heating values of 3,900 British thermal units per pound (Btu/lb) (wet basis) for bagasse and 4,250 Btu/lb (wet basis) for wood.

Air pollutant emission rates for $SO_2$, $NO_x$, and CO will be continuously monitored using continuous emission monitoring systems (CEMS). A continuous opacity monitoring system (COMS) will not be installed on the boiler stack. NSPS Subpart Db requires a COMS; however, due to moisture interference from water added to the flue gas stream in the wet sand separator and urea injection system, a COMS would not provide accurate opacity data. Therefore, an alternative monitoring procedure (AMP) is being applied for. The EPA has previously granted a similar AMP to U.S. Sugar Corporation for Boiler No. 8 located at the Clewiston, Florida, mill. The EPA approved the use of ESP secondary power input as an AMP to opacity for Boiler No. 8. HEF's proposed AMP for the biomass boiler is presented in Appendix H.

The following control device parameters will also be continuously monitored: ESP total secondary power input, SNCR system urea injection rate, and DSI rate.

# 3.0 AIR QUALITY REVIEW REQUIREMENTS

Federal and state air regulatory requirements for a major new or modified source of air pollution are discussed in Sections 3.1 through 3.4. The applicability of these regulations to the proposed HEF Facility is presented in Section 3.5. These regulations must be satisfied before the proposed project can be approved.

## 3.1 National and State Ambient Air Quality Standards

The existing applicable national and Florida Ambient Air Quality Standards (AAQS) are presented in Table 3-1. Primary national AAQS were promulgated to protect the public health, and secondary national AAQS were promulgated to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Areas of the country in violation of AAQS are designated as nonattainment areas and new sources to be located in or near these areas may be subject to more stringent air permitting requirements.

Florida has adopted state AAQS in Rule 62-204.240, F.A.C. These standards are the same as the national AAQS, except for the following exceptions. For $SO_2$, Florida has adopted the former 24-hour secondary standard of 260 micrograms per cubic meter ($\mu g/m^3$) and the former annual average secondary standard of 60 $\mu g/m^3$. In addition, Florida has not yet adopted the revised AAQS for $O_3$ or Pb. The EPA also recently promulgated a 1-hour $NO_2$ AAQS and a 1-hour $SO_2$ AAQS, which Florida has not yet adopted.

## 3.2 PSD Requirements

### *3.2.1 General Requirements*

Under federal and state of Florida PSD review requirements, all new major sources (facilities) and all major modifications to existing major sources (facilities) of air pollutants regulated under the Clean Air Act (CAA) must be reviewed and a pre-construction permit issued. Florida's State Implementation Plan (SIP), which contains PSD regulations, has been approved by the EPA; therefore, PSD approval authority has been granted to FDEP.

A "major facility" is defined as any one of 28 named source categories that have the potential to emit 100 TPY or more, or any other stationary facility that has the potential to emit 250 TPY or more, of any pollutant regulated under the CAA, other than GHGs. For GHGs, a "major facility" is one with the potential to emit 100,000 TPY or more of $CO_2e$. Potential to emit means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment. Once a new source is determined to be a "major facility" for a particular pollutant, any pollutant emitted in amounts greater than the PSD significant emission rate is subject to PSD review. For an existing major source for which a modification is proposed, the modification is subject to PSD review if the net increase in emissions due to the modification is greater than the PSD significant emission rate for any pollutant (i.e., a major modification). The PSD significant emission rates are shown in Table 3-2.

The PSD regulations limit the amount of allowable air quality concentration increase over a specified "baseline" concentration for $SO_2$, $PM_{10}$, and $NO_2$. The magnitude of the allowable increment depends on the classification of the area in which a new source (or modification) will be located or have an impact. Three classifications are designated based on criteria established in the CAA Amendments. Congress promulgated areas as Class I (international parks, national wilderness areas, and memorial parks larger than 5,000 acres and national parks larger than 6,000 acres) or as Class II (all areas not designated as Class I). No Class III areas, which would be allowed greater deterioration than Class II areas, were designated. EPA's class designation and allowable PSD increments are presented in Table 3-1. The state of Florida has adopted EPA's class designations and allowable PSD increments for $SO_2$, $PM_{10}$, and $NO_2$.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Federal PSD requirements are contained in 40 CFR 52.21, Prevention of Significant Deterioration of Air Quality. The state of Florida has adopted its own PSD regulations (Rule 62-212.400, F.A.C.), consistent with the federal PSD regulations. Major new facilities and major modifications are required to undergo the following analysis related to PSD for each pollutant emitted in significant amounts:

1. Control technology review
2. Source impact analysis
3. Air quality analysis (monitoring)
4. Source information
5. Additional impact analyses

In addition to these analyses, a new facility must also be reviewed with respect to Good Engineering Practice (GEP) stack height regulations. Discussions concerning each of these requirements are presented in the following subsections.

### *3.2.2 Control Technology Review*

The control technology review requirements of the federal and state PSD regulations require that all applicable federal and state emission-limiting standards be met, and that BACT be applied to control emissions from the source. The BACT requirements are applicable to all regulated pollutants for which the increase in emissions from the facility exceeds the respective significant emission rate (see Table 3-2).

BACT is defined in 40 CFR 52.21 (b)(12) as:

> An emissions limitation (including a visible emission standard) based on the maximum degree of reduction of each pollutant subject to regulation under the Act which would be emitted by any proposed major stationary source or major modification which the

Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts, and other costs, determination is achievable through application of production processes and available methods, systems, and techniques) for control of such pollutant. In no event shall application of best available control technology (BACT) result in emissions of any pollutant, which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular part of a source 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 and shall provide for compliance by means, which achieve equivalent results.

BACT is defined in Rule 62-210.200(40), F.A.C., as:

(a) 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
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.

(b) 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.

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

(d) In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60, 61, and 63.

BACT was promulgated within the framework of the PSD requirements in the 1977 amendments of the CAA [Public Law 95-95; Part C, Section 165(a)(4)]. The primary purpose of BACT is to optimize consumption of PSD air quality increments and thereby enlarge the potential for future economic growth without significantly degrading air quality (EPA, 1978; 1980). Guidelines for the evaluation of BACT can be found in EPA's *Guidelines for Determining Best Available Control Technology (BACT)* (EPA, 1978), in the PSD *Workshop Manual-Draft* (EPA, 1980), and in the *New Source Review Workshop Manual-Draft* (EPA, 1990). These guidelines were promulgated by the EPA to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters. In addition, through implementation of these guidelines, BACT analyses must be conducted on a case-by-case basis, and BACT in one area may differ than BACT in another area. According to the EPA (1980), "BACT analyses for the same types of emissions unit and the same pollutants in different locations or situations may determine that different control strategies should be applied to the different sites, depending on site-specific factors."

BACT requirements are intended to ensure that the control systems incorporated in the design of a facility reflect the latest in control technologies used in a particular industry and take into consideration existing and future air quality in the vicinity of the proposed facility. BACT cannot be less stringent than any applicable NSPS for a source. An evaluation of the air pollution control techniques and systems is required, including a cost-benefit analysis of alternative control technologies capable of achieving a higher degree of emission reduction than the proposed control technology. The cost-benefit analysis requires the documentation of the material, energy, and economic penalties associated with the proposed and alternative control systems, as well as the environmental benefits derived from these systems. A decision on BACT is to be based on sound judgment, balancing environmental benefits with energy, economic, and other impacts (EPA, 1978).

The EPA has issued a draft guidance document on the top-down approach entitled *Top-Down Best Available Control Technology Guidance Document* (EPA, 1990). EPA's BACT guidelines include a "top-down" approach to determine the "best available control technology" for application at a particular facility. These guidelines discuss the BACT as a "case-by-case" analysis to identify the most stringent emission control technologies that have been applied to the same or similar source categories, and then to select a BACT emission rate, taking into account technical feasibility and energy, environmental, and economic impacts specific to the project. The most effective control alternative not rejected from the analysis is proposed as BACT.

EPA's BACT guidelines establish a specific five-step analytical process for conducting a BACT determination. The five steps consist of:

1. Identifying the potentially applicable control technologies for the proposed process or source
2. Evaluating the technical options for feasibility taking into consideration source-specific factors
3. Comparing the remaining control technologies based on effectiveness
4. Evaluating the remaining options taking into consideration energy, environmental, and economic impacts
5. Selecting BACT based on the above analyses

### *3.2.3 PSD Tailoring Rule*

On May 13, 2010, EPA promulgated a final rule which regulates GHGs under the PSD and Title V permitting programs (referred to as the "GHG Tailoring Rule"). EPA is tailoring the applicability criteria that determine which stationary sources and modification projects become subject to permitting requirements for GHG emissions under the PSD and Title V programs of the CAA. This rulemaking is necessary because without it, PSD and Title V requirements would apply, as of January 2, 2011, at the 100- and 250-TPY emission threshold levels. Because GHGs are emitted in much higher quantities compared to regulated PSD pollutants, this would create an extreme permitting burden. Therefore, this tailoring rule sets much higher thresholds for GHGs. EPA is phasing in the GHG permitting requirements in two steps.

In Phase 1, beginning January 2, 2011, if a new source is subject to PSD due to an emissions increase of a pollutant other than GHGs, and the new source has a potential-to-emit of 75,000 TPY $CO_2e$ or more, the source will be subject to PSD review for GHGs. In Phase 2, beginning July 1, 2011, in addition to sources described in Phase 1, the PSD program will apply to new sources of GHGs with a potential-to-emit of 100,000 TPY $CO_2e$ or more.

Under federal PSD rules, ethanol facilities are not considered to be classified as "chemical plants," and therefore the major source threshold is 250 TPY potential emissions instead of 100 TPY. However, FDEP has not adopted this provision of the federal PSD rules. Therefore, any new ethanol facility with the potential-to-emit 100 TPY or more of any regulated air pollutant would be considered a major source and subject to PSD review under Florida rules. If the potential-to-emit is greater than 100 TPY but less than 250 TPY, such a facility would be a major PSD source under FDEP rules but not EPA rules. A request was submitted to FDEP in early 2011 to have the Florida rules changed to mirror the EPA rules.

EPA has proposed to defer PSD review for GHG emissions from biogenic sources for a period of 3 years (Federal Register, Vol. 76, No. 54, March 21, 2011). EPA has proposed the following changes to the federal PSD rules, codified at 40 CFR 52.21:

> *For purposes of this paragraph, prior to [DATE 3 YEARS AFTER THE EFFECTIVE DATE OF THE FINAL DEFERRAL RULE], the mass of the greenhouse gas carbon dioxide shall not include carbon dioxide emissions resulting from the combustion or decomposition of non-fossilized and biodegradable organic material originating from plants, animals, or micro-organisms (including products, by-products, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of nonfossilized and biodegradable organic material. The term "biogenic $CO_2$ emissions" is defined here as emissions of $CO_2$ from a stationary source directly resulting from the combustion or decomposition of biologically-based materials other than fossil fuels).*

EPA then provides examples of "biogenic $CO_2$ emissions" to include, but not be limited to:

- $CO_2$ from fermentation during ethanol production
- $CO_2$ derived from combustion of biological material, including all types of wood and wood waste, forest residue, and agricultural material

## 3.3 Source Impact Analysis

A source impact analysis must be performed for a proposed major source or major modification subject to PSD review, and for each pollutant for which the increase in emissions exceeds the PSD significant emission rate (Table 3-2). PSD regulations specifically provide for the use of atmospheric dispersion models in performing impact analyses, estimating baselines and future air quality levels, and determining compliance with AAQS and allowable PSD increments. Models designated by the EPA must normally be used in performing the impact analysis. Specific applications for other than EPA-approved models require EPA's consultation and prior approval. Guidance for the use and application of dispersion models is presented in EPA's publication *Guideline on Air Quality Models* (EPA, 1980).

To address compliance with AAQS and PSD Class II increments, a source impact analysis must be performed for the criteria pollutants. However, this analysis is not required for a specific pollutant if the net increase in impacts as a result of the new source or modification is below significant impact levels, as presented in Table 3-1. The significant impact levels are threshold levels that are used to determine the level of air impact analyses needed for the project. If the new or modified source's impacts are predicted to be less than significant, then the source's impacts will not have a significant adverse affect on air quality, and additional modeling with other sources is not required. However, if the source's impacts are predicted to be greater than the significant impact levels, additional modeling with other sources is required to demonstrate compliance with AAQS and PSD increments. The EPA has proposed significant impact levels for Class I areas as follows:

| | | |
|---|---|---|
| $SO_2$ | 3-hour | 1 μg/m$^3$ |
| | 24-hour | 0.2 μg/m$^3$ |
| | Annual | 0.1 μg/m$^3$ |
| $PM_{10}$ | 24-hour | 0.3 μg/m$^3$ |
| | Annual | 0.2 μg/m$^3$ |
| $NO_2$ | Annual | 0.1 μg/m$^3$ |

Although these levels have not been officially promulgated as part of the PSD review process.and may not be binding for states in performing PSD reviews, the proposed levels serve as a guideline in assessing a source's impact in a Class I area. EPA's action to incorporate Class I significant impact levels in the PSD process is part of implementing the NSR provisions of the 1990 CAA Amendments. Because the process of developing the regulations will be lengthy, the EPA believes that the proposed rules concerning the significant impact levels are appropriate to assist states in implementing the PSD permitting process. FDEP has accepted the use of these significant impact levels. Source impact analyses for PSD Class I areas are performed if the source is within 200 kilometers (km) of the Class I Area.

Various lengths of record for meteorological data can be used for impact analysis. A 5-year period is normally used with corresponding evaluation of highest, second-highest (HSH) short-term concentrations for comparison to AAQS or PSD increments. The meteorological data are selected based on an evaluation of measured weather data from a nearby weather station that represents weather conditions at the project site. The criteria used in this evaluation include determining the distance of the project site to the weather station, comparing topographical and land use features between the locations, and determining availability of necessary weather parameters.

The term "HSH" refers to the highest of the second-highest concentrations at each receptor for each year (i.e., the highest concentration at each receptor is discarded, and the highest of the remaining concentrations at each receptor is identified). The second-highest concentration is important because short-term AAQS specify that the standard cannot be exceeded at any location more than once a year. If fewer than 5 years of meteorological data are used in the modeling analysis, the highest concentration at each receptor normally must be used for comparison to air quality standards.

Similarly, the term "H6H" refers to the highest of the sixth-highest concentrations at each receptor over 5 years (i.e., the six highest concentrations at each receptor for 5 years combined are identified, and the highest five concentrations at each receptor are discarded; the highest remaining concentration is identified).

The term "baseline concentration" evolves from federal and state PSD regulations and refers to a concentration level corresponding to a specified baseline date and certain additional baseline sources.

By definition, in the PSD regulations as amended August 7, 1980, baseline concentration means the ambient concentration level that exists in the baseline area at the time of the applicable baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established and includes:

1. The actual emissions representative of facilities in existence on the applicable date
2. The allowable emissions of major stationary facilities that commenced before January 6, 1975, for $SO_2$ and $PM_{10}$ concentrations, or February 8, 1988, for $NO_2$ concentrations, but that were not in operation by the applicable baseline date

The following emissions are not included in the baseline concentration and therefore affect PSD increment consumption:

1. Actual emissions from any major stationary facility on which construction commenced after January 6, 1975, for $SO_2$ and $PM_{10}$ concentrations, and after February 8, 1988, for $NO_2$ concentrations
2. Actual emission increases and decreases at any stationary facility occurring after the baseline date

In reference to the baseline concentration, the term "baseline date" actually includes three different dates:

1. The major facility baseline date, which is January 6, 1975, in the cases of $SO_2$ and $PM_{10}$, and February 8, 1988, in the case of $NO_2$
2. The minor facility baseline date, which is the earliest date after the trigger date on which a major stationary facility or major modification subject to PSD regulations submits a complete PSD application
3. The trigger date, which is August 7, 1977, for $SO_2$ and $PM_{10}$, and February 8, 1988, for $NO_2$

The minor source baseline date for $SO_2$ and PM (TSP) has been set as December 27, 1977, for the entire state of Florida [Rules 62-204.200(22) and 204.360, F.A.C.]. The minor source baseline for $NO_2$ has been set as March 28, 1988 [Rules 62-204.200(22) and 204.360, F.A.C.]. It should be noted that references to PM (TSP) are also applicable to $PM_{10}$.

### *3.3.1 Air Quality Monitoring Requirements*

In accordance with requirements of 40 CFR 52.21(m) and Rule 62-212.400(5)(f), any application for a PSD permit must contain an analysis of continuous ambient air quality data in the area affected by the proposed major stationary facility or major modification. For a new major facility, the affected pollutants are those that the facility would potentially emit in significant amounts. For a major modification, the pollutants are those for which the net emissions increase exceeds the significant emission rate (see Table 3-2).

Ambient air monitoring for a period of up to 1 year is generally appropriate to satisfy the PSD monitoring requirements. A minimum of 4 months of data is required. Existing data from the vicinity of the proposed source may be used if the data meet certain quality assurance requirements; otherwise, additional data may need to be gathered. Guidance in designing a PSD monitoring network is provided in EPA's *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA, 1987a).

The regulations include an exemption that excludes or limits the pollutants for which an air quality analysis must be conducted. This exemption states that FDEP may exempt a proposed major stationary facility or major modification from the monitoring requirements, with respect to a particular pollutant, if the emissions increase of the pollutant from the facility or modification would cause, in any area, air quality impacts less than the *de minimis* levels presented in Table 3-2. If a facility's predicted impacts are less than the *de minimis* levels, preconstruction monitoring will not be required pursuant to Rule 62-212.400(3)(e), F.A.C.

### 3.3.2 Source Information/GEP Stack Height

Source information must be provided to adequately describe the proposed project. The general type of information required for this project is presented in Section 2.0.

The 1977 CAA Amendments require that the degree of emission limitation required for control of any pollutant not be affected by a stack height that exceeds GEP or any other dispersion technique. On July 8, 1985, the EPA promulgated final stack height regulations (EPA, 1985a). FDEP has adopted identical regulations (Rule 62-210.550, F.A.C.). GEP stack height is defined as the highest of:

1. 65 meters, or
2. A height established by applying the formula:

   $Hg = H + 1.5L$

   where: $Hg$ = GEP stack height,

   $H$ = Height of the structure or nearby structure, and

   $L$ = Lesser dimension (height or projected width) of nearby structure(s); or
3. A height demonstrated by a fluid model or field study.

"Nearby" is defined as a distance up to five times the lesser of the height or width dimensions of a structure or terrain feature, but not greater than 0.8 km. Although GEP stack height regulations require that the stack height used in modeling for determining compliance with AAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater.

The stack height regulations also allow increased GEP stack height beyond that resulting from the above formula in cases where plume impaction occurs. Plume impaction is defined as concentrations measured or predicted to occur when the plume interacts with elevated terrain. Elevated terrain is defined as terrain that exceeds the height calculated by the GEP stack height formula.

### 3.3.3 Additional Impact Analysis

In addition to air quality impact analyses, federal and state of Florida regulations require analyses of the impairment to visibility and the impacts on soils and vegetation that would occur as a result of the proposed source [40 CFR 52.21(o) and Rule 62-212.400(8), F.A.C.]. These analyses are to be conducted primarily for PSD Class I areas. Impacts as a result of general commercial, residential, industrial, and other growth associated with the source also must be addressed. These analyses are required for each pollutant emitted in significant amounts (Table 3-2).

### 3.3.4 Air Quality Related Values

An air quality related values (AQRVs) analysis is required to assess the potential risk to AQRVs in PSD Class I areas. The Everglades National Park (ENP) is the closest Class I area to HEF, and is located about 170 km (106 miles) south of the site. The Chassahowitzka National Wilderness Area (NWA) is located about 203 km northwest of the HEF site and is beyond the 200-km distance that requires a source impact analysis.

The U.S. Department of the Interior in 1978 administratively defined AQRVs to be:

> *All those values possessed by an area except those that are not affected by changes in air quality and include all those assets of an area whose vitality, significance, or integrity is dependent in some way upon the air environment. These values include visibility and those scenic, cultural, biological, and recreational resources of an area that are affected by air quality.*
>
> *Important attributes of an area are those values or assets that make an area significant as a national monument, preserve, or primitive area. They are the assets that are to be preserved if the area is to achieve the purposes for which it was set aside (Federal Register, 1978).*

AQRVs include visibility, freshwater and coastal wetlands, dominant plant communities, unique and rare plant communities, soils and associated periphyton, and the wildlife dependent on these communities for habitat. Rare, endemic, threatened, and endangered species of the national park and bioindicators of air pollution (e.g., lichens) must also be evaluated.

## 3.4 Nonattainment Rules

Based on the current nonattainment provisions (Rule 62-212.500, F.A.C.), all major new facilities and modifications to existing major facilities located in a nonattainment area must undergo nonattainment review. A new major facility is required to undergo this review if the proposed pieces of equipment have the potential to emit 100 TPY or more of the nonattainment pollutant. HEF will be located in Highlands County, which is classified as an attainment area for all criteria pollutants (Rule 62-204.340, F.A.C.).

## 3.5 Emission Standards

### 3.5.1 New Source Performance Standards

The NSPS are a set of national emission standards that apply to specific categories of new sources. As stated in the CAA Amendments of 1977, these standards "shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction the Administrator determines has been adequately demonstrated." The NSPS are contained in 40 CFR 60. The following describes NSPS that are potentially applicable to the proposed ethanol production Facility and biomass boiler.

***Subpart Da***

The Federal NSPS exist for electric utility steam generating units (40 CFR 60, Subpart Da). The NSPS applies to all electrical generating units capable of combusting more than 250 MMBtu/hr heat input of fossil fuel (either alone or in combination with any other fuel) for which construction commenced after September 18, 1978. Subpart Da limits emissions of $NO_x$, $SO_2$, and PM from fossil fuel and wood firing.

The EPA issued changes to these NSPS on February 27, 2006 (71 Federal Register 9866). The revisions are applicable to new affected facilities that commence construction after February 28, 2005. The NSPS emission limit for PM is 0.14 pound per megawatt hour (lb/MW-hr) gross energy output, or 0.015 lb/MMBtu heat input. As an alternative, PM is limited to 0.03 lb/MMBtu and 99.9 percent reduction from the uncontrolled PM level when combusting solid fuel.

$SO_2$ emissions are limited to 1.4 lb/MW-hr or 95 percent reduction, based on a 30-day rolling average. "Resource recovery" facilities are limited to 1.20 lb/MMBtu. A resource recovery facility is a facility that combusts more than 75 percent non-fossil fuel on a calendar quarter heat input basis.

Subpart Da limits $NO_x$ emissions to 1.0 lb/MW-hr gross energy output based on a 30-day rolling average.

Visible emissions are limited to 20-percent opacity (6-minute average) except up to 27-percent opacity is allowed for one 6-minute period per hour.

***Subpart Db***

The NSPS for Industrial Boilers, 40 CFR 60, Subpart Db, is potentially applicable to the new biomass boiler if the new boiler is not subject to Subpart Da. Subpart Db regulates Industrial-Commercial-Institutional Boilers for which construction, modification, or reconstruction commenced after June 19, 1989. It applies to boilers with a heat input capacity of greater than 100 MMBtu/hr. Bagasse, biogas, and propane are not regulated fuels under Subpart Db; however, wood and fuel oil are regulated.

Under Subpart Db, there is no emission limit for $SO_2$ for boilers firing wood. Also, there is no $SO_2$ emission limit for boilers firing very low-sulfur fuel oil (i.e., fuel oil with sulfur content not greater than 0.5 percent by weight) or gaseous fuel, provided the potential $SO_2$ emission rate of these fuels is 0.32 lb/MMBtu or less [Section 60.42b(k)].

The applicable limit for PM emissions is 0.030 lb/MMBtu for boilers combusting wood or wood with any other fuels, and for which construction commenced after February 28, 2005 [Section 60.43b(h)]. There is no PM limit when firing natural gas only.

The applicable opacity standard is contained in 40 CFR 60.43b(f), and is 20-percent opacity (6-minute average), except 27-percent opacity is allowed for one 6-minute period per hour. The opacity limit applies any time that wood or wood with any other fuel is being fired in the boiler.

Subpart Db contains $NO_x$ emission standards for fossil fuel firing. There are no specific standards for wood firing; however, when burning natural gas in combination with wood, the applicable standard is 0.20 lb/MMBtu for units for which construction commenced after July 9, 1997 [Section 60.44b(l)(1)]. A continuous $NO_x$ emissions monitor is also required for sources subject to the $NO_x$ standard.

Subpart Db also contains continuous opacity monitoring requirements for any unit subject to the opacity standard under 60.43b(f) [refer to 63.48b(a)]. However, sources which employ a PM CEMS are not required to have a COMS.

***Subpart Eb***

The NSPS for Large MWCs for which construction is commenced after September 20, 1994 (40 CFR 60, Subpart Eb) are potentially applicable to the new biomass boiler due to the potential to burn yard waste, as defined in Subpart Eb. This subpart applies to MWCs with the capacity to burn more than 250 tons per day (TPD) of municipal solid waste (MSW). However, any "cofired combustor" is not subject to Subpart Eb. A "cofired combustor" is defined as "a unit combusting MSW with non-MSW fuel (e.g., coal, industrial process waste) and subject to a federally enforceable permit limiting the unit to combusting a fuel feed stream, 30 percent or less of the weight of which is comprised, in aggregate, of MSW as measured on a calendar quarter basis". "Municipal solid waste" is defined as:

> *household, commercial/retail, and/or institutional waste. Household waste includes material discarded by single and multiple residential dwellings, hotels, motels, and other similar permanent or temporary housing establishments or facilities. Commercial/retail waste includes material discarded by stores, offices, restaurants, warehouses, nonmanufacturing activities at industrial facilities, and other similar establishments or facilities. Institutional waste includes material discarded by schools, nonmedical waste discarded by hospitals, material discarded by nonmanufacturing activities at prisons and government facilities, and material discarded by other similar establishments or facilities. Household, commercial/retail, and institutional waste does not include used oil; sewage sludge; wood pallets; construction, renovation, and demolition wastes (which includes but is not limited to railroad ties and telephone poles); clean wood; industrial process or manufacturing wastes; medical waste; or motor vehicles including motor vehicle parts or vehicle fluff). Household, commercial/retail, and institutional wastes include:*
>
> *(1) Yard waste;*
>
> *(2) Refuse-derived fuel; and*
>
> *(3) Motor vehicle maintenance materials limited to vehicle batteries and tires except as specified in §60.50b(g).*

"Yard waste" is defined in Subpart Eb as follows:

> *Yard waste means grass, grass clippings, bushes, shrubs, and clippings from bushes and shrubs that are generated by residential, commercial/retail, institutional, and/or industrial sources as part of maintenance activities associated with yards or other private or public lands. Yard waste does not include construction, renovation, and demolition wastes, which are exempt from the definition of municipal solid waste in this section. Yard waste does not*

*include clean wood, which is exempt from the definition of municipal solid waste in this section.*

To obtain the exemption, the owner or operator of the cofired combustor must notify the EPA of the exemption claim, incorporate the requirements for cofired combustors into their construction permit, and keeps records of fuels fired in the combustor on a calendar quarter basis.

***Subpart Kb***

Subpart Kb is applicable to volatile organic liquid (VOL) storage vessels (including petroleum liquid storage vessels) for which construction commenced after July 23, 1984. These standards are applicable to VOL storage tanks with a storage capacity of greater than 39,894 gallons, provided a liquid of a minimum specified maximum true vapor pressure is stored in the tank. The NSPS requires the tanks be fitted with an internal floating roof, an external floating roof, or that the tank be vented to a control device with a minimum 95-percent control efficiency. An alternative control system equivalent to these options may be approved by the EPA.

***Subparts NNN and RRR***

Subpart NNN applies to distillation operations in the synthetic organic chemical manufacturing industry (SOCMI), while Subpart RRR applies to reactor processes in the SOCMI. The NSPS requires control of VOC emissions from these processes, and that certain emission limits or control efficiencies be met.

***Subpart VVa***

Equipment leaks of VOC emissions from SOCMI processes are covered under Subpart VVa. Generally, for all equipment (valves, flanges, pumps, compressors) in VOC service, a leak detection and repair (LDAR) program is required.

***Subpart IIII***

Air emissions from stationary CI ICE are regulated under Subpart IIII. Emissions of NMHC, $NO_x$, CO, and PM are regulated. Emission standards are based on the size of engine (horsepower), the model year, and the use of the engine, i.e., non-emergency, emergency, or fire pump. Subpart IIII references other subparts for some emission limits, such as 40 CFR 89 and 94. These subparts generally regulate the manufacturers of internal combustion engines.

### *3.5.2 National Emission Standards for Hazardous Air Pollutants*

EPA has issued National Emission Standards for Hazardous Air Pollutants (NESHAPs) for various source categories under 40 CFR 63. These standards are referred to as MACT standards because they require that MACT be applied to control the emissions of HAPs.

On March 21, 2011, the EPA issued revised MACT standards for industrial/commercial/institutional boilers for both major HAP sources and for area sources. These rules are codified under 40 CFR 63, Subpart DDDDD for major sources, and Subpart JJJJJJ (Subpart $J^6$) for area sources. Also in March 2011, the EPA proposed revised MACT standards for electric utility steam generating units (40 CFR 63, Subpart UUUUU).

Subpart $J^6$ regulates only PM emissions from new biomass-fired boilers. The PM limit is 0.03 lb/MMBtu (40 CFR 63.11201) for boilers with a heat input capacity of 30 MMBtu/hr or greater. In addition to this limit, a biennial tune-up of the boiler must be conducted.

### *3.5.3 Clean Air Interstate Rule*

The Clean Air Interstate Rule (CAIR) was promulgated under 40 CFR 96 to reduce the emissions of precursor pollutants to $O_3$ and fine particulate formation, and therefore the interstate transport of $O_3$ and fine particulates. CAIR applies to electric utility steam generating units. CAIR regulates $NO_x$ and $SO_2$ emissions. At this time, the legal status of CAIR is uncertain. CAIR was challenged in the U.S. Court of Appeals, which vacated the rule, but it appears that the court's decision may be reconsidered or reviewed by the U.S. Supreme Court. A revised CAIR rule was published by EPA in 2010, but has yet to be finalized.

### *3.5.4 Florida Rules*

Several Florida emissions-limiting standards exist for steam generating units. Fossil fuel steam generating units with greater than 250 MMBtu/hr heat input are subject to the emission limitations of Rule 62-296.405(2), F.A.C., pertaining to PM, $SO_2$, $NO_x$, and visible emissions. Emissions limitations and visible emissions requirements for carbonaceous fuel-burning equipment are contained in Rule 62-296.410, F.A.C. Also, FDEP has adopted EPA NSPS by reference in Rule 62-204.800(7). Therefore, HEF is required to meet the same emissions, performance testing, monitoring, reporting, and record keeping requirements as those described in Subsection 3.4.1. FDEP has the authority for implementing the NSPS requirements in Florida.

### *3.5.5 Florida Air Permitting Requirements*

FDEP regulations require any new source to obtain an air permit prior to construction. Major new sources must meet the appropriate PSD and nonattainment requirements as discussed previously. Required permits and approvals for air pollution sources include NSR for nonattainment areas, PSD, NSPS, NESHAPs, Permit to Construct, and Permit to Operate. The requirements for construction permits and approvals are contained in Rules 62-4.030, 62-4.050, 62-4.210, 62-210.300(1), and Chapter 62-212.400, F.A.C. Specific emission standards are set forth in Chapter 62-296, F.A.C.

## 3.6 Source Applicability

### *3.6.1 Area Classification*

The project site is located in Highlands County, which has been designated by the EPA and FDEP as an attainment area for all criteria pollutants. Highlands and surrounding counties are designated as PSD Class II areas for $SO_2$, $PM_{10}$, and $NO_2$. The nearest Class I area to the site is the ENP, located about 170 km (106 miles) south of the HEF facility.

### *3.6.2 PSD Review*

***Pollutant Applicability***

"Chemical process plants" are included in the list of 28 major PSD source categories, for which the major source threshold is 100 TPY. However, in May 2007, the EPA clarified that this category does not include ethanol production facilities that produce ethanol by natural fermentation included in NAICS codes 325193 or 312140. Although the FDEP has not adopted this change into their state rules, the HEF facility will be a new major stationary facility because potential emissions of certain regulated pollutants exceed 250 TPY (for example, potential CO emissions exceed 250 TPY). Therefore, PSD review is required for any pollutant for which the increase in emissions due to the new facility is greater than the PSD significant emission rates (see Table 3-2).

Presented in Table 3-3 are the future potential annual emissions from the HEF facility, based on the emissions presented in Section 2.0. As shown, the increase in emissions exceeds the PSD significant emission rates for $SO_2$, $NO_x$, CO, PM, $PM_{10}$, $PM_{2.5}$, VOC, and SAM. As a result, PSD review applies for these pollutants.

Potential GHG emissions from the proposed HEF facility were presented in Table 2-29. The potential-to-emit GHGs for the facility is 533,987 TPY $CO_2e$. As a result, HEF would be subject to PSD permitting for GHG emissions since potential emissions of GHG pollutants are above 100,000 TPY $CO_2e$. PSD review applies to any PSD pollutant emitted in significant amounts. BACT would apply to each such pollutant. The PSD significant emission rate for GHGs is 75,000 TPY $CO_2e$. Therefore, BACT would also apply to GHG emissions.

Notwithstanding the above applicability of PSD to GHG emissions, EPA has issued guidance and a proposed rule to defer for a period of three (3) years the application of the PSD and Title V permitting requirements to biogenic $CO_2$ emissions from bioenergy and other biogenic stationary sources (Federal Register, Vol. 76, No. 54, March 21, 2011). This action proposes to defer for a period of three (3) years the consideration of "biogenic $CO_2$ emissions" when determining whether a stationary source meets the PSD and Title V applicability thresholds, including those for the application of BACT. Stationary sources that combust biomass and construct or modify during the deferral period will avoid the application of PSD to the biogenic $CO_2$ emissions resulting from those actions. This deferral applies only to $CO_2$ emissions and does not affect non-GHG pollutants or other GHGs (e.g., $CH_4$ and $N_2O$) emitted from the combustion of biomass fuel.

As described in Section 3.2.3, PSD review would apply to any new major source if the source has the potential to emit GHGs of 100,000 TPY $CO_2e$ or more. EPA has proposed that the mass of the $CO_2$ counted towards the 100,000 TPY threshold shall not include $CO_2$ emissions resulting from the combustion or decomposition of non-fossilized and biodegradable organic material originating from plants, animals, or micro-organisms (including products, by-products, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of nonfossilized and biodegradable organic material). Emissions of other GHGs would be counted towards the 100,000 TPY threshold.

In the case of the HEF facility, the $CO_2$ emissions from the biomass-fired boiler would therefore not be counted towards the facility's potential to emit GHGs. In addition, the $CO_2$ emissions from the ethanol process (fermentation and distillation) would not count towards the facility's potential to emit GHGs, since such emissions result from fermentation and from the production of liquids recovered from the decomposition of nonfossilized and biodegradable organic material. The potential emissions of GHGs from the HEF facility, excluding biogenic $CO_2$ emissions, are 10,451 TPY $CO_2e$, which is well below the PSD threshold of 100,000 TPY. As a result, PSD review for GHGs is not addressed in this application.

***<u>Source Impact Analysis</u>***

A source impact analysis was performed for $PM_{2.5}$, $PM_{10}$, $SO_2$, $NO_x$, and CO emissions resulting from the proposed HEF Facility. This analysis is presented in Section 6.0. Additional impacts upon the PSD Class I are also addressed and presented in Section 7.0. Impact analyses are not required for VOC emissions (ozone) at this time, as the current air dispersion models do not adequately model this pollutant.

Based on the source impact analysis, the pollutant impacts of the proposed project are predicted to be above the EPA Class II significant impact levels for $PM_{2.5}$ and $PM_{10}$ for the 24-hour and annual averaging times; $SO_2$ for the 24-hour and 1-hour averaging times; and $NO_2$ for the 1-hour averaging time. Therefore, additional modeling analysis of the impacts on the PSD Class II areas was performed for these pollutants and averaging times.

Based on the source impact analysis, the pollutant impacts of the proposed project are predicted to be below the proposed EPA Class I significant impact levels, except for the 3-hour $SO_2$ impacts. Therefore, additional modeling analysis of the impacts on the PSD Class I area was performed for this pollutant and averaging time.

***Ambient Monitoring Analysis***

Based on the increase in emissions from the proposed HEF Facility (see Table 3-3), a pre-construction ambient monitoring analysis is required for $PM_{10}$, $PM_{2.5}$, $SO_2$, $NO_x$, CO, VOC, and SAM, and monitoring data are required to be submitted as part of the application. However, if the net increase in impacts of a pollutant is less than the applicable *de minimis* monitoring concentration, then an exemption from submittal of pre-construction ambient monitoring data may be obtained [40 CFR 52.21(i)(8)]. In addition, if the EPA has not established an acceptable ambient monitoring method for the pollutant, monitoring is not required.

As shown in Section 6.10, HEF's maximum impacts are predicted to be below the PSD *de minimis* concentration levels and significant impact levels for all pollutants except $PM_{10}$ and $O_3$. For $O_3$, the EPA has established a PSD *de minimis* monitoring level for a project based on an increase in VOC emissions of 100 TPY or more, which would require a pre-construction ambient monitoring analysis. Because HEF's VOC emissions are greater than 100 TPY, pre-construction ambient monitoring analysis for $O_3$ (based on VOC emissions) is required as part of the application. Pre-construction monitoring data for $O_3$ are presented in Section 4.0. For SAM, no *de minimis* concentration level has been established, and therefore pre-construction monitoring is not required for this pollutant.

***GEP Stack Height Impact Analysis***

The new HEF cogeneration boiler will have a minimum stack height of 150 ft. The maximum stack height will not exceed the *de minimis* GEP stack height of 65 meters (213 ft), and therefore, the project will be in compliance with the GEP stack height rules.

### *3.6.3 Emission Standards*

***New Source Performance Standards***

The NSPS apply to all steam generating units capable of combusting more than 250 MMBtu/hr heat input of fossil fuel (either alone or in combination with any other fuel). The HEF cogeneration boiler will be limited to firing less than 250 MMBtu/hr heat input of fossil fuel, based on the maximum capacity of the natural gas burners (249 MMBtu/hr). As a result, the boiler will not be subject to the NSPS in 40 CFR 60, Subpart Da.

***Subpart Db***

The NSPS for Industrial Boilers, 40 CFR 60, Subpart Db, will be applicable to the new cogeneration boiler. Subpart Db regulates Industrial-Commercial-Institutional Boilers for which construction, modification, or reconstruction commenced after June 19, 1989. It applies to boilers with a heat input capacity of greater than 100 MMBtu/hr. Bagasse is not a regulated fuel under Subpart Db; however, wood and natural gas are regulated.

As described in Section 3.5.1, there is no emission limit for $SO_2$ for boilers firing wood. Also, there is no $SO_2$ emission limit for boilers firing gaseous fuel, provided the potential $SO_2$ emission rate of the natural gas is 0.32 lb/MMBtu or less [Section 60.42b(k)]. Since HEF will be firing pipeline natural gas, the potential $SO_2$ emissions rate of the natural gas will be much less than 0.32 lb/MMBtu.

The applicable limit for PM emissions is 0.030 lb/MMBtu for boilers combusting wood or wood with any other fuels, and for which construction commenced after February 28, 2005 [Section 60.43b(h)]. There is no PM limit when firing natural gas only.

The applicable opacity standard is contained in 40 CFR 60.43b(f), and is 20-percent opacity (6-minute average), except 27-percent opacity is allowed for one 6-minute period per hour. The opacity limit applies any time that wood or wood with any other fuel is being fired in the boiler.

Subpart Db contains $NO_x$ emission standards for fossil fuel firing. There are no specific standards for wood firing; however, when burning natural gas in combination with wood, the applicable standard is 0.20 lb/MMBtu for units for which construction commenced after July 9, 1997 [Section 60.44b(l)(1)]. A continuous $NO_x$ emissions monitor is also required for sources subject to the $NO_x$ standard.

Subpart Db also contains continuous opacity monitoring requirements for any unit subject to the opacity standard under 60.43b(f) [refer to 63.48b(a)]. As described previously, HEF is proposing to implement an AMP (ESP power input monitoring) in lieu of installing a COMS on the boiler.

The new boiler will comply with all other applicable provisions of Subpart Db.

***Subpart Eb***

As described in Subsection 3.6.3.1, the NSPS for Large MWCs (40 CFR 60, Subpart Eb) are potentially applicable to the HEF boiler due to the potential to burn yard waste, which is defined as MSW in Subpart Eb. However, the boiler will meet the requirements in Subpart Eb for a "cofired combustor", and therefore will not be subject to Subpart Eb. HEF will comply with Subpart Eb by notifying the EPA of the exemption claim, incorporating the requirements for cofired combustors into the construction permit, and keeping records of fuels fired in the combustor on a calendar quarter basis. The records will demonstrate that the unit will combust a fuel feed stream, 30 percent or less of the weight of which is comprised, in aggregate, of MSW, as measured on a calendar quarter basis.

***Subpart Kb***

The tanks within the HEF Facility that will be subject to Subpart Kb consist of the following:

- Fuel Ethanol Storage Tank – 1,000,000 gallon capacity
- 200 Proof Ethanol Storage Tank – 100,000 gallon capacity

- Off-Spec Ethanol Tank – 100,000 gallon capacity
- Denaturant/Gasoline Tank – 100,000 gallon capacity

The remaining tanks will not meet the applicability criteria of Subpart Kb, either based on size (i.e., less than 39,894 gallon capacity), or based on vapor pressure.

***Subparts NNN and RRR***

Subpart NNN applies to distillation operations in the SOCMI, while Subpart RRR applies to reactor processes in the SOCMI. The EPA has previously determined that these NSPS do not apply to ethanol produced by biological processes. Since the ethanol produced by the HEF Facility will be produced by biological processes, Subparts NNN and RRR do not apply to the HEF Facility.

***Subpart VVa***

Equipment leaks of VOC emissions from SOCMI processes are regulated under Subpart VVa. Even though it has been determined that Subpart NNN and RRR NSPS are not applicable to HEF because the ethanol will be produced from biological processes and not from synthetic organic chemicals, Subpart VVa will apply to the HEF Facility. HEF will comply with all requirements of Subpart VVa, including a VOC equipment LDAR. A preliminary LDAR program is contained in Appendix G.

***Subpart IIII***

The NSPS for internal combustion engines contained in Subpart IIII will be applicable to HEF's proposed emergency electrical generators and fire pump engine. The NSPS include emission limits for NMHC, $NO_x$, CO, and PM. Opacity limits are also set. The HEF emergency internal combustion engines will meet all requirements of the NSPS.

***NESHAPs***

The proposed HEF boiler, and the proposed HEF Facility, will not be a major source of HAPs. Therefore, the facility will be an area source of HAPs. On March 21, 2011, the EPA issued revised MACT standards for industrial/commercial/institutional boilers for area sources. These rules are codified under 40 CFR 63, Subpart JJJJJJ (Subpart $J^6$).

Subpart $J^6$ regulates only PM emissions from new biomass-fired boilers. The PM limit is 0.03 lb/MMBtu (40 CFR 63.11201) for boilers with a heat input capacity of 30 MMBtu/hr or greater. In addition to this limit, a biennial tune-up of the boiler must be conducted, and a one-time energy assessment conducted.

***State of Florida Standards***

The applicable state of Florida emission limits for new fossil fuel steam generators with less than 250 MMBtu/hr heat input due to fossil fuels are the same as the applicable NSPS. For the cogeneration boiler, the applicable NSPS are 40 CFR 60 Subpart Db, as described above. For carbonaceous fuel-burning units, the standards are no more stringent than the NSPS. The new cogeneration boiler must also comply with the Florida emission standards contained in Rules 62-296.406 and 62-296.410(2)(b)1, F.A.C.

Fossil fuel steam generators with less than 250 MMBtu/hr heat input must apply BACT for control of $SO_2$ and PM emissions, and meet a visible emissions limit of 20 percent opacity except for either one 6-minute period per hour during which opacity shall not exceed 27 percent, or one 2-minute period per hour during which opacity shall not exceed 40 percent (Rule 62-296.406).

Carbonaceous fuel-fired boilers must meet a PM limit of 0.20 lb/MMBtu, and an opacity limit of 30 percent, except that 40-percent opacity is permissible for not more than 2 minutes in any one hour [Rule 62-296.410(2)(b)].

The HEF boiler will comply with all of these requirements.

The State of Florida regulations also include provisions for reducing and minimizing fugitive dust emissions for facility operations. A preliminary fugitive dust minimization plan is included in Appendix I.

# 4.0 AMBIENT MONITORING ANALYSIS

## 4.1 Monitoring Requirements

In accordance with requirements of 40 CFR 52.21(m) and Rule 62-212.400(5)(f), F.A.C., an air quality analysis must be conducted for each criteria and non-criteria pollutant subject to regulation under the CAA before a major stationary source is constructed. Criteria pollutants are those pollutants for which AAQS have been established. Non-criteria pollutants are those pollutants that may be regulated by emission standards for which AAQS have not been established. This analysis may be performed by the use of modeling and/or by monitoring the air quality. In addition, if EPA has not established an acceptable ambient monitoring method for the pollutant, monitoring is not required.

Based on the potential emissions from the HEF facility (see Section 2.0 and Table 3-3), pre-construction ambient monitoring analyses for $SO_2$, $PM_{10}$, $PM_{2.5}$, $NO_2$, CO, $O_3$ (based on VOC emissions), and SAM may be required as part of the application. The facility may be exempted from the ambient monitoring analyses if it can be demonstrated that the proposed facility's maximum air quality impacts will not exceed the PSD *de minimis* concentration levels and, for $O_3$, the proposed facility's potential emissions will not exceed 100 TPY of VOC emissions.

As presented in Subsection 6.10.1 and shown in Table 4-1, HEF's maximum impacts due to the proposed project only are predicted to be below the PSD *de minimis* concentration levels for $SO_2$, $NO_2$ and CO, but above the *de minimis* concentration levels for $PM_{2.5}$, $PM_{10}$, and $O_3$. For $PM_{2.5}$ and $PM_{10}$, the predicted maximum increase in 24-hour average concentrations due to the project are 23.4 $\mu g/m^3$ and 33.7 $\mu g/m^3$, respectively, compared to the *de minimis* level of 10 $\mu g/m^3$. Because the predicted maximum 24-hour $PM_{2.5}$ and $PM_{10}$ concentrations are greater than the *de minimis* levels, a pre-construction ambient monitoring analysis is required for both $PM_{2.5}$ and $PM_{10}$ as part of the application.

For $O_3$, EPA has established a PSD *de minimis* monitoring level for a project based on an increase in VOC emissions of 100 TPY or more, which would require a pre-construction ambient monitoring analysis. Because HEF's potential VOC emissions are greater than 100 TPY, a pre-construction ambient monitoring analysis for $O_3$ is required as part of the application.

Ambient background concentrations for $SO_2$ and $NO_2$ are also presented in this section to support the air impact analysis.

## 4.2 $PM_{2.5}$ and $PM_{10}$ Ambient Monitoring Analysis

Ambient $PM_{2.5}$ and $PM_{10}$ monitoring data from existing monitoring stations are included in this application to satisfy the pre-construction monitoring requirements and to support the air quality impact analysis. Measured ambient $PM_{2.5}$ and $PM_{10}$ data from the nearest monitors are presented in Table 4-2. The most representative monitors for the HEF site that measures $PM_{2.5}$ and $PM_{10}$ concentrations are located in Sarasota and Belle Glade (AIRS Nos. 12-115-1006 and 12-099-0008). The station located in Belle Glade in Palm Beach County is approximately 86 km (53 miles) from the site. The station located in Sarasota in Sarasota County is approximately 114 km (71 miles) from the site. Although both monitors are not located near the proposed project, both monitor locations have a rural setting (particularly the Belle Glade station), similar to the proposed HEF project location.

As shown in Table 4-2, the 3-year average of the 98$^{th}$ percentile 24-hour $PM_{2.5}$ concentration measured from 2008 to 2010 at the site in Belle Glade was 14.7 μg/m$^3$. This concentration is less than the existing 24-hour average $PM_{2.5}$ AAQS standard 35 μg/m$^3$. In addition, the second-highest 24-hour average $PM_{10}$ concentration measured from 2008 through 2010 at the site in Sarasota was 60 μg/m$^3$. This maximum concentration is less than the existing 24-hour average $PM_{10}$ AAQS of 150 μg/m$^3$.

For purposes of ambient background concentrations for use in the modeling analysis, the highest annual and the 3-year average of the 98$^{th}$ percentile 24-hour average $PM_{2.5}$ concentrations of 6.53 μg/m$^3$ and 14.7 μg/m$^3$, respectively, recorded at the Belle Glade monitor were selected. Similarly, the highest annual and the HSH 24-hour average $PM_{10}$ concentrations of 20 μg/m$^3$ and 60 μg/m$^3$, respectively, recorded at the Sarasota monitor during 2008 were selected.

## 4.3 $SO_2$ Ambient Monitoring Analysis

Ambient $SO_2$ monitoring data from existing monitoring stations are included in this application to support the air quality impact analysis. A summary of existing continuous ambient $SO_2$ data for monitors located in the vicinity of HEF is presented in Table 4-3. Data are presented for the last 3 years of record, 2008 to 2010. Data from the closest two $SO_2$ monitors to the HEF site was obtained. The closest station, located in Plant City (Monitor ID No. 12-057-3002) in Hillsborough County, is approximately 121 km (75 miles) from the site. The other station located in Winter Park (AIRS No. 12-095-2002) in Orange County operated during 2008 through 2010, but is located approximately 154 km (96 miles) from the site and in a more urban setting than the HEF site. The station in Winter Park is considered more representative of the HEF site than the Plant City station because the Plant City monitor is influenced by a large $SO_2$ source (CF Industries).

The monitor in Winter Park shows that ambient $SO_2$ concentrations were well below the ambient air quality standards of: 196.5 μg/m$^3$, 99$^{th}$ percentile 1-hour average; 1,300 μg/m$^3$, maximum 3-hour average; 260 μg/m$^3$, maximum 24-hour average; and 60 μg/m$^3$, annual average.

For purposes of an ambient background concentration for use in the modeling analysis, the 99$^{th}$ percentile of the daily maximum 1-hour average and the second highest 24-hour average $SO_2$ concentrations of 18.3 μg/m$^3$ and 5.8 μg/m$^3$, respectively, recorded at the Winter Park monitor during 2010 were selected.

## 4.4 Ozone Ambient Monitoring Analysis

Ambient $O_3$ monitoring data from the nearest monitoring station is included in this application to satisfy the pre-construction monitoring requirement. Highlands County and adjacent counties are classified as attainment or maintenance areas for $O_3$. The nearest monitor to the HEF site that measures $O_3$ concentrations is located in Sebring (Monitor ID No. 12-055-0003) in Highlands County, approximately 2 km (1.2 miles) from the site. This monitor is considered to be representative of the HEF site due to its distance from HEF and its rural location.

As shown in Table 4-4, the second-highest 1-hour average $O_3$ concentration measured from 2008 through 2010 at Sebring was 153 µg/m$^3$. This maximum concentration is less than the existing 1-hour average $O_3$ AAQS of 235 µg/m$^3$. In addition, the 3-year average of the fourth highest 8-hour average $O_3$ concentrations was 114 µg/m$^3$ and is below the revised 8-hour average $O_3$ AAQS of 147 µg/m$^3$.

## 4.5 $NO_2$ Ambient Monitoring Analysis

Ambient $NO_2$ monitoring data from existing monitoring stations are included in this application to support the modeling analysis. The nearest monitor to the HEF site that measures $NO_2$ concentrations is located in Sarasota (Monitor ID No. 12-151-1006) in Sarasota County, and is approximately 114 km (71 miles) from the site. This monitor is considered to be the most representative of the HEF site due to the similar rural setting of the monitor (although not as rural as the HEF site).

As shown in Table 4-5, the 3-year average of the 98$^{th}$ percentile of the daily maximum 1-hour $NO_2$ concentrations measured during 2010 at the Sarasota station was 45.1 µg/m$^3$. This concentration was used as the 1-hour background $NO_2$ concentration in the modeling analysis.

# 5.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

## 5.1 Introduction

The 1977 CAA Amendments established requirements for the approval of pre-construction permit applications under the PSD program. As discussed in Subsection 3.2, one of these requirements is that BACT be installed for applicable pollutants. This section presents the proposed BACT for these pollutants. The approach to the BACT analysis is based on the regulatory definitions of BACT, as well as consideration of EPA's current policy guidelines requiring a "top-down" approach. A BACT determination requires a site-specific analysis of the technical, economic, environmental, and energy impacts of the proposed and alternative control technologies (see Rule 62-212.400, F.A.C.).

The "top-down" approach consists of the following five steps, as described in the New Source Review Workshop Manual-Draft (EPA, 1990):

1) Identification of all available control technologies
2) Elimination of technically infeasible control options
3) Ranking of the technically feasible control technologies based on their effectiveness
4) Evaluation of the economic, environmental, and energy impacts of the feasible control options
5) Selection of BACT based on consideration of the above factors

The PSD regulations require that new major stationary sources and major modifications to existing major sources undergo a control technology review for each pollutant that may potentially be emitted above significant amounts. In the case of the proposed HEF project, $PM/PM_{10}/PM_{2.5}$, $NO_x$, $SO_2$, CO, VOC, and SAM emissions require a BACT analysis utilizing the top-down approach. In each case, BACT is an emission limitation that meets the maximum degree of emission reduction after taking into account HEF's specific economic, environmental, and energy impacts, as well as consideration of the application of the technologies proposed. If it is impractical to impose an emission limit, a work practice standard may be specified.

The following sections provide the required BACT analysis.

## 5.2 Biomass Handling System and Truck Traffic

Fugitive PM emissions will result from various activities associated with the HEF project, including materials handling activities (bagasse, wood, and ash), wind erosion from storage piles, and vehicular traffic over unpaved and paved surfaces. The inherent moisture of the sugarcane and sweet sorghum feedstock (approximately 70- to 80-percent moisture), bagasse generated from the ethanol process (approximately 50-percent moisture), and wood fuel delivered to the HEF facility (approximately 35- to 50-percent moisture) will aid in reducing potential PM emissions from the handling of these materials.

HEF will utilize reasonable precautions for controlling fugitive PM emissions from these sources. These include the following:

- Enclosing material drop points, shredders and screens wherever practical
- Contouring storage piles to minimize wind erosion
- Utilizing water sprays on storage piles as needed
- Paving all main plant access roads
- Sweeping and watering of paved surfaces as needed to remove dust
- Utilizing water sprays on ash material as necessary

A preliminary Best Management Practices (BMPs) for fugitive dust control at the proposed HEF facility are presented in Appendix I. These reasonable precautions represent BACT for the control of fugitive PM emissions.

Baghouse controls on conveyor transfer points within the biomass handling system are not proposed as BACT. The moisture content of the biomass feedstock (70 to 80 percent) as well as the moisture content of bagasse exiting the ethanol process renders the use of baghouses both infeasible and unnecessary. U.S. Sugar Corporation in Clewiston, Florida, installed baghouses on their bagasse conveying system several years ago in an attempt to provide better fugitive dust control. However, these baghouse soon failed due to plugging of the bags due to the high moisture atmosphere they operated in. The baghouses also experienced rapid corrosion of the fan and other baghouse internals. Therefore, these baghouses were soon abandoned, and the permit obtained to install them was revised to delete the baghouses.

As described above, the inherent moisture content of the biomass fuels, along with enclosures and other appropriate measures as identified in the proposed BMPs is adequate to minimize fugitive dust emissions. An opacity limit of 10 percent on the biomass handling system is proposed to insure that nuisance dust emissions do not occur.

## 5.3 Ethanol Production Process

The ethanol production process will result in the emissions of primarily ethanol, with minor amounts of other VOCs. These emissions will occur from the fermentation, distillation, and dehydration processes, as the ethanol is separated from the fermentation products. There are two recognized, feasible means of controlling these emissions: wet scrubbing and thermal oxidation. Each of these technologies can reduce VOC emissions by 98 percent or more. However, thermal oxidation results in destroying the ethanol product, and therefore is disadvantageous over the wet scrubbing option, which is able to recover some ethanol product. Thermal oxidation would also result in additional fossil fuel burning and emissions of criteria pollutants, including GHGs.

HEF is proposing to use two wet scrubbers for VOC control, each with a minimum 98 percent control efficiency. The wet scrubber controlling emissions from the fermentation process will use process water as the scrubbing media, whereas the distillation/dehydration scrubber will utilize soft water. The fermentation scrubber is considered to be a product recovery device, since it functions to recover ethanol by sending the spend scrubbing liquid back to the beer buffer tank. The maximum estimated emissions from the fermentation scrubber is 69.3 TPY, of which 56.2 TPY is ethanol, and only 2.9 TPY are HAPs. The maximum estimated emissions from the distillation/dehydration scrubber is 10.2 TPY, of which 5.8 TPY is ethanol and only 1.0 TPY are HAPs.

The use of wet scrubbing technology with 98 percent or greater removal efficiency is consistent with other BACT determinations for ethanol manufacturing plants, for those utilizing corn as the feedstock as well as those using biomass, such as Highlands Ethanol, LLC (Verenium) and Southeast Renewable Fuels, LLC.

## 5.4 Bagasse Boiler

As an introduction to the BACT analysis for the proposed HEF bagasse boiler, the goals of this project must be emphasized. The primary goals of the HEF project are as follows:

- Generating steam and electricity from a renewable resource
- Generating "green" jobs in Florida, in lieu of purchasing out-of-state fossil fuels
- Reduction in GHG emissions due to the use of annually renewable fuels
- Accomplishing the above while remaining economically viable

The selection of BACT for each pollutant must be consistent with these goals. It is noted that HEF will be uniquely tied to an agricultural operation (the annual growing of sugarcane and sweet sorghum), and thus will be subject to weather conditions as well as shifts in agricultural commodity prices. In addition, the price of ethanol, the primary product of the facility, will be subject to fluctuation in the future. Lastly, the electricity provided to the electric grid by the facility will be sold through a power purchase agreement, which is fundamentally different than a dedicated electric utility power plant, which solely generates electricity for sale to the grid (no steam cogeneration). All of these aspects of the project render the HEF project fundamentally different than an electric utility boiler, in operation and in economics. Electric utility boilers enter into long-term, fixed contracts essentially guaranteeing a steady revenue stream for 20 years or more into the future. Such boilers can build additional costs into their budgets for items such as air pollution control equipment, since such costs will ultimately be passed on to the consumer.

### *5.4.1 Particulate Matter ($PM/PM_{10}/PM_{2.5}$)*

***Previous BACT Determinations***

As part of the BACT analysis, a review was performed of previous BACT determinations for $PM/PM_{10}/PM_{2.5}$ emissions from biomass-fired industrial and electric utility boilers listed in the RACT/BACT/LAER Clearinghouse (RBLC) on EPA's web page. From this information, BACT determinations issued within the last 10 years (i.e., since 2001) were identified. A summary of these BACT determinations is presented in Table 5-1. Other recent BACT determinations, not included in the RACT/BACT/LAER Clearinghouse, are also shown in Table 5-1.

From the review of previous BACT determinations and non-BACT permits, it is evident that the overwhelming majority of $PM/PM_{10}/PM_{2.5}$ BACT determinations for new biomass-fired stoker/grate industrial and electric utility boilers have been based on cyclone/ESP technology. The latest such determination was for Southeast Renewable Fuels, LLC, in Hendry County, Florida, which received a $PM/PM_{10}$ permit limit of 0.015 lb/MMBtu for a bagasse-fired boiler. Aspen Power was also permitted for 0.012 lb/MMBtu for PM using ESP technology on a woody biomass-fired boiler. FBEnergy in Manatee County, Florida, was issued a non-BACT permit for a stoker grate boiler firing woody biomass and was permitted for 0.01 lb/MMBtu for $PM/PM_{10}$ emissions.

BACT determinations and non-BACT permits for biomass boilers equipped with ESPs have been in the range of 0.01 to 0.026 lb/MMBtu for $PM/PM_{10}$. The most recent determinations are in the range of 0.015 to 0.14 lb/MMBtu. Two recent determinations in 2010 resulted in limits of 0.040 and 0.026 lb/MMBtu, based on ESP technology.

Fabric filters have also been used, but primarily on fluidized bed boilers. Gainesville Renewable Energy (GREC) received a 0.015 lb/MMBtu limit, while Highlands Ethanol (Verenium) received a 0.01 lb/MMBtu limit for stillage burning. ADAGE received a high BACT limit of 0.028 lb/MMBtu. In another case (Public Service of New Hampshire-Schiller Station) the determination was for a fluidized bed boiler (0.025 lb/MMBtu). Another case (Biomass Energy) was issued a minor source permit limit (not a BACT limit) and the limit was 0.012 lb/MMBtu. This unit also employed a spray dryer absorber for $SO_2$ control, and the fabric filter is an integral part of the $SO_2$ control system as the "filter cake" aids in $SO_2$ absorption. In two other cases using a fabric filter, the PM BACT limits were set at 0.020 lb/MMBtu. In at least one of these, the fabric filter followed a spray dryer absorber for $SO_2$ control.

A fabric filter has never known to have been used on a bagasse-fired boiler.

In some cases, wet scrubbers have been used for PM control alone or in combination with ESPs for $SO_2$ control.

It also evident from the review that all BACT determinations for bagasse-fired boilers have been based on wet scrubbers or ESPs. Fabric filters have not been used on bagasse-fired boilers. They appear to have been used primarily in cases involving biomass fuel only where there was a fluidized bed boiler and a spray dryer absorber for $SO_2$ control. BACT determinations for bagasse-fired boilers range from 0.015 to 0.15 lb/MMBtu. The most recent determination was 0.015 lb/MMBtu for Southeast Renewable Fuels, based on a wet cyclone followed by an ESP.

***Identification of Potentially Applicable Control Technologies***

This section identifies potentially applicable $PM/PM_{10}/PM_{2.5}$ control technologies, based upon the review conducted above and review of the published literature regarding PM control devices. Since the same technologies are used to control PM, $PM_{10}$, and $PM_{2.5}$ emissions, they will be referred to collectively as "PM" in the remainder of this section.

**Fuel Techniques**

Fuel substitution, or fuel switching, is a common means of reducing emissions from combustion sources, such as electric utilities and industrial boilers. It involves replacing the current fuel with a fuel that emits less of a given pollutant when burned. In the case of a biomass boiler, replacement fuels include fuel oil, natural gas, and propane. Since fuel oil and natural gas would be available at the HEF site, this is a potentially applicable control process or procedure.

**Pretreatment Devices**

The performance of PM control devices can often be improved through pretreatment of the gas stream. For PM control devices, pretreatment consists of the following techniques:

- Settling Chambers
- Elutriators
- Momentum Separators
- Mechanically-Aided Separators
- Cyclones (wet or dry)

Of these five techniques, cyclones offer the highest control efficiency, typically in the range of 60 to 90 percent. All of the other techniques have control efficiencies less than 30 percent.

Cyclones use inertia to remove particles from a spinning gas stream. Gas enters the cyclone tangentially, causing a cyclonic, spinning motion. The larger particles move outwards toward the cyclone walls due to centrifugal force. For particles that are large, typically greater than 10 microns, inertial momentum overcomes the fluid drag forces so that the particles reach the cyclone walls and fall down into a discharge hopper. After leaving the cyclonic flow area, the gas spirals upwards through the cyclone discharge. For smaller particles, the fluid drag forces are greater than the momentum forces and the particles follow the gas out of the cyclone. Gas leaves the cyclone through a port at the top of the vessel, and is ducted to the ID fan inlet or to a secondary PM control device, such as an ESP, baghouse, or wet scrubber.

Pretreatment devices are potentially applicable to the proposed bagasse boiler.

**Electrostatic Precipitators**

Collection of PM by ESPs involves the ionization of the gas stream passing through the ESP, the charging, migration, and collection of particles on oppositely charged surfaces, and the removal of particles from the collection surfaces. There are two basic types of ESPs: dry and wet. In dry ESPs, the particulate is removed by rappers, which vibrate the collection surface, dislodging the material and allowing it to fall into the collection hoppers. Wet ESPs use water to rinse the particulates off of the collection surfaces.

ESPs have several advantages when compared with other control devices. They are very efficient collectors, even for small particles, with greater than 97 percent control efficiency. ESPs can also treat large volumes of gas with a low pressure drop. ESPs can operate over a wide range of temperatures and generally have low operating cost. The disadvantages of ESPs are large capital cost, large space requirements, and difficulty in controlling particles with high resistivity.

Compared to fabric filters, ESPs also have several advantages, especially in regard to biomass boilers. ESPs have much lower fire potential than fabric filters, particularly where the biomass has a low density and wide range of particle sizes, such as that exhibited by bagasse. The small, light particles are much more able to be carried out of the furnace as burning embers, which could cause a fire in the baghouse. The second advantage of ESPs is that they cannot plug due to high moisture or humidity in the flue gas stream, as can happen in a baghouse. A bagasse boiler produces a very wet, high moisture flue gas steam (20- to 30-percent moisture) due to the high moisture content of the bagasse (approximately 50 percent).

ESPs are potentially applicable to the bagasse boiler.

**Fabric Filters**

Baghouses, or fabric filters, utilize porous fabric to remove PM from a gas stream. In a fabric filter, PM is removed from the flue gas as it passes through a fabric filter media, such as woven cloths or felts; hence the term "fabric filter." During fabric filtration, dusty gas is sent through the fabric by forced-draft fans. The fabric is responsible for some filtration, but more significantly it acts as support for the dust layer that accumulates on the fabric. The layer of dust, also known as the "filter cake," is a highly efficient filter, even for submicron particles. Woven fabrics rely on the filtration of the dust cake much more than felted fabrics.

The filters are normally arranged as a number of cylinders or tubes (commonly referred to as "bags") through which the flue gas is directed. The filters are contained in a housing which has gas inlets and outlets. The flue gas enters the cylindrical filter from the bottom and flows upward, from either the inside of the cylinder to the outside or the opposite depending upon the design. Particulate collection occurs through several mechanisms, including filtration, gravitational settling, direct impaction, inertial impaction, diffusion, and electrostatic attraction.

When the pressure drop reaches a predefined level, indicating the filter cake is becoming too thick, a section of the filters is taken offline for cleaning. Various methods are used to clean the bags in the fabric filter. The three general types of cleaning are shaker cleaning, reverse-air cleaning, and pulse-jet cleaning. All three types of cleaning methods ensure the fabric filter achieves the same low emission rates. $PM/PM_{10}$ control efficiencies for fabric filters are typically greater than 97 percent.

The shaker cleaning is accomplished by taking the bags off-line, shaking the bags of the fabric filter, and then deflating the bag by inducing a vacuum. The PM collected on the bags is dislodged and then falls into the collection hoppers at the bottom of the fabric filter.

In reverse air fabric filters, the PM is collected on the inside of the filter bags. Cleaning is accomplished by introducing a reverse flow of air through the bags. This causes the bag to collapse, thereby dislodging the filter cake. The dislodged PM falls into the collection hoppers for disposal.

In the pulse-jet method of cleaning, cleaning is accomplished off-line by directing a short burst of compressed air inside the filter bags. This burst produces a shock wave, which travels down the length of the bag, dislodging the accumulated dust cake. The collected PM then falls into the hoppers located below the bags. This is currently the best practice for cleaning.

Fabric filters offer high efficiencies and are flexible to treat many types of dusts and a wide range of volumetric gas flow rates. In addition, fabric filters can be operated with low pressure drop.

Potential disadvantages of fabric filters are:

- High moisture gas streams and sticky particles can plug the fabric and blind the filter, requiring bag replacement
- High temperatures can damage fabric bags
- Fabric filters have a potential for fire or explosion

Fabric filters are potentially applicable to the bagasse boiler.

**Wet Scrubbers**

Wet scrubbers are systems that involve particle collection by contacting the particles with a liquid, usually water. The aerosol particles are transferred from the gaseous airstream to the surface of the liquid by several different mechanisms. Wet scrubbers create a liquid waste that must be treated prior to disposal. $PM/PM_{10}$ control efficiencies for wet scrubbing systems range from about 50 to 95 percent, depending on the type of scrubbing system used and the characteristic of the gas stream. Typical wet scrubber types are as follows:

- Spray Chamber
- Packed-Bed
- Impingement Plate
- Venturi
- Orifice
- Condensation

The advantages of wet scrubbers compared to other PM collection devices are that they can collect flammable and explosive dusts safely, absorb gaseous pollutants, and collect mists. Scrubbers can also cool hot gas streams. The disadvantages are the potential for corrosion and freezing, the potential of water and solid waste pollution problems, and high energy costs. All types of wet scrubbers are potentially applicable to the HEF bagasse boiler.

**Summary**

The potentially applicable control technologies for the bagasse boiler are listed in Table 5-2.

***Identification of Technically Feasible Control Alternatives***

In this section, the technical feasibility of each potentially applicable control technology is assessed. Those technologies that are found to be technically infeasible will not be considered further in the BACT analysis.

**Fuel Techniques**

Fuel substitution for HEF's bagasse boiler is technically feasible. The primary fuel will be sorghum bagasse and sugar cane bagasse, which will be supplemented by wood. Substitution of the biomass fuel with fossil fuel such as fuel oil or propane is technically feasible.

**Pretreatment Devices**

Pretreatment devices are technically feasible for application to the bagasse boiler. The proposed bagasse boiler will utilize a mechanical cyclone of a design similar to that employed on U.S. Sugar Clewiston Boiler Nos. 7 and 8. This will provide pretreatment before the gas stream enters the ESP as well as provide protection for the ID fan from sand abrasion during biomass firing.

**Electrostatic Precipitators**

ESPs are technically feasible for application to the bagasse boiler. The proposed boiler will utilize an ESP of the dry, wire plate type. This same ESP type is also currently used on two modern bagasse-fired boilers (Boiler Nos. 7 and 8) at the U.S. Sugar Clewiston Mill as well as the RGVSG new bagasse boiler. This system has been demonstrated to be very effective for PM control.

**Fabric Filters**

Fabric filters are considered technically infeasible for application to the proposed bagasse boiler. There are only few known applications of a fabric filter to a grate-type biomass-fired boiler (see Table 5-1), and the fabric filter was used due to the use of a spray dryer for $SO_2$ control. No hybrid suspension/grate bagasse-fired boiler is known to utilize a fabric filter. Further, serious concerns exist over the ability of a baghouse to operate long-term in a harsh environment with a flue gas containing significant moisture and light, stringy bagasse particles. There are also serious concerns with potential fire hazards due to burning particles being carried out of the boiler. This is the nature of bagasse-fired boilers, where the bagasse fuel is light and stringy. As a result, fabric filter technology was not further considered for the HEF proposed bagasse boiler.

**Wet Scrubbers**

Wet scrubbers are technically feasible for the bagasse boiler.

**Summary**

The technically feasible PM/$PM_{10}$ controls for the proposed bagasse boiler are listed in Table 5-2. As shown, there are five types of PM abatement methods with various techniques of each method. Each available technique is listed, and identified as feasible or infeasible. As presented in Table 5-2, fabric filters are not considered technically feasible as a control alternative for the grate-type boiler.

***Ranking of Technically Feasible Control Alternatives***

Each available PM control technique is listed with its associated efficiency estimate in Table 5-2, and is ranked based on control efficiency. As shown in Table 5-2, ESPs and baghouses are ranked with the highest efficiency of the technically feasible control technologies, having an estimated PM removal efficiency of greater than 97 percent. Wet scrubbers are the next most effective, followed by cyclones with an estimated PM removal efficiency of 60 to 90 percent. Other technologies have not demonstrated equivalent levels of control for PM.

***Evaluation of Economic, Environmental, and Energy Impacts of Feasible Technologies***

**Fuel Techniques**

For fuel substitution to be practical, there must be a suitable replacement fuel available at an acceptable cost. HEF's primary fuel for the bagasse boiler will be biomass (bagasse, with minor amounts of wood).

Substitution of fossil fuel, such as oil or natural gas, would result in an unacceptable cost impact, i.e., the facility would not be economically viable if required to use fuel oil or natural gas on a on-going basis. The boiler will burn natural gas only in the event of an interruption in the biomass supply. Therefore, this option is not considered further.

**Pretreatment**

The bagasse boiler will utilize the highest ranked pretreatment device: cyclones (mechanical dust collectors). The mechanical dust collectors will be located prior to the ESP, and will remove sand and larger PM from the flue gas stream before they enter the ESP, thereby protecting the ID fan.

**Electrostatic Precipitators**

HEF is proposing to utilize an ESP for control of $PM/PM_{10}/PM_{2.5}$ emissions. The ESP, in combination with the mechanical dust collector, will result in the highest control efficiency determined to be feasible for the bagasse boiler. The ESP will be designed for a PM control efficiency of 97 percent or greater. This is a proven technology that is utilized on the newest bagasse-fired boilers (U.S. Sugar Clewiston Boiler Nos. 7 and 8, and RGVSG).

Because HEF is proposing to utilize the highest ranked $PM/PM_{10}$ control technology, a detailed economic analysis of the proposed cyclone/ESP control system was not performed.

**Wet Scrubbers**

Wet scrubbers are feasible for the proposed the bagasse boiler, but do not result in a greater PM removal efficiency than the proposed control system using cyclones and an ESP. In addition, a wet scrubber would have a higher energy usage than the ESP, and a liquid waste stream that would need to be disposed of. For these reasons, wet scrubbers were not considered further for the bagasse boiler.

**Baghouses**

HEF is not proposing to utilize a baghouse for control of $PM/PM_{10}/PM_{2.5}$ emissions, due to the unproven nature of baghouses on hybrid suspension/grate boilers burning bagasse. Also, the ESP can provide equivalent control level as a baghouse, and will result in the highest control efficiency determined to be feasible for the bagasse boiler. Because HEF is proposing to utilize the highest ranked $PM/PM_{10}$ control technology (ESP), a detailed economic analysis of the baghouse technology was not performed.

**Environmental**

Of the feasible control technologies, the proposed ESP for the bagasse boiler would have the least environmental impact. Wet scrubbers would be more energy intensive and create a liquid waste stream. Additional PM controls on the bagasse boiler would result in an insignificant reduction in ambient $PM_{10}$ impacts.

**Energy**

The electrical energy required to run the ESP system will reduce the amount of electricity available to HEF's customers. The ESP is a high-voltage device and requires electrical energy. The energy required to operate the ESP is approximately 280 kW, or a maximum of about 2,200 MW-hours per year. To achieve the low PM levels proposed for the bagasse boiler, wet scrubbers would require substantially more energy to operate than an ESP. Baghouses would also require additional energy due to the higher pressure drop associated with baghouses.

***Selection of BACT and Rationale***

The identification, technical evaluation, and ranking of the available control technologies demonstrates that the proposed control technology for the bagasse boiler of a mechanical dust collector followed by an ESP provides the maximum degree of emission reduction for PM emissions from bagasse-fired boilers. The evaluation of the energy and environmental impacts demonstrate that these controls do not have significant environmental or energy impacts. Fabric filters appear to have only been employed on fluidized bed boilers burning biomass where spray dryer absorbers were used for $SO_2$ control.

Design information for the proposed ESP is provided in Subsection 2.9.2, Table 2-7. A vendor quote is provided in Appendix J. An emission rate of 0.015 lb/MMBtu is proposed as BACT for $PM/PM_{10}$ emissions, based on the evaluations and recent BACT decisions on similar bagasse boiler projects. This limit would represent the lowest PM limit on any bagasse-fired boiler. The $PM/PM_{10}$ emission limit is also proposed as a surrogate for direct $PM_{2.5}$ emissions.

The proposed limit is lower than the NSPS under 40 CFR 60, Subpart Db. Subpart Db applies to boilers with a heat input capacity of greater than 100 MMBtu/hr. Bagasse burning is not a regulated fuel under Subpart Db; however, wood and natural gas are regulated. Under Subpart Db, the applicable limit for PM emissions is 0.030 lb/MMBtu for boilers combusting wood and for which construction commenced after February 28, 2005 [§60.43b(h)].

Also, the proposed boiler will be subject to MACT standards for industrial boilers located at area sources (40 CFR 63, Subpart J[6]). The MACT PM limit is 0.03 lb/MMBtu for new sources. The proposed BACT limit of 0.015 lb/MMBtu is much lower than the MACT limit.

### *5.4.2 Nitrogen Oxides ($NO_x$)*

***Previous BACT Determinations***

As part of the BACT analysis, a review was performed of previous $NO_x$ BACT determinations for similar biomass-fired industrial and electric utility boilers listed in the RBLC on EPA's web page. From this information, BACT determinations issued within the last 10 years (i.e., since 2001) were identified. A summary of these BACT determinations is presented in Table 5-3. Also included are several non-BACT permit limits, which includes the lowest $NO_x$ emission limit identified to date for a biomass-fired boiler.

From the review of previous BACT determinations, it is evident that most $NO_x$ BACT determinations for new biomass-fired industrial and electric utility boilers have been based on both selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) systems, as well as and good combustion practices (GCPs). To contrast the varying boiler types and control technologies, determinations in Table 5-3 have been arranged according to boiler type (stoker/grate versus fluidized bed), and by BACT and non-BACT determinations.

For BACT determinations for stoker/grate type boilers, such as that proposed by HEF, previous determinations are in the range of 0.065 to 0.31 lb/MMBtu. The most recent determination was for Southeast Renewable Fuels, with a limit of 0.10 lb/MMBtu, achieved by SNCR, SCR, or a combination of the two. This is also a bagasse-fired boiler. Other recent determinations for stoker/grate boilers include NRG Energy, 0.060 lb/MMBtu with regenerative SCR (RSCR).

BACT determinations for bubbling fluidized bed (BFB) boilers are in the range of 0.06 to 0.075 lb/MMBtu. These are all very recent determinations (2010). These are lower than the stoker/grate type boilers due to the inherently lower uncontrolled $NO_x$ emissions produced by a fluidized bed boiler. Note that a number of these determinations are for electric utility type boilers, which have a very different economic structure compared to the HEF boiler. The HEF boiler will support an industrial process (ethanol production).

We Energies in Wisconsin is one of the latest biomass-fired boilers to receive a PSD permit (3/28/2011). This is a proposed 800 MMBtu/hr circulating fluidized bed (CFB) boiler firing woody biomass. A fabric filter is to be used for PM control, with an SNCR system for $NO_x$ control. SCR was rejected on the basis of cost considerations. The $NO_x$ BACT limit was set at 0.10 lb/MMBtu, 30-day rolling average, on the basis of SNCR.

The lowest BACT determinations to date for all boilers, in the range of 0.06 to 0.075 lb/MMBtu $NO_x$, were based on the use of SCR with a fluidized bed boiler, which is a fundamentally different process than the hybrid suspension/grate boiler proposed by HEF.

The lowest BACT determinations where SNCR was used are Highlands Ethanol (Verenium) at 0.075 lb/MMBtu, Southeast Renewable Fuels at 0.08 lb/MMBtu (with fluidized bed boiler), and Southeast Renewable Fuels at 0.10 lb/MMBtu (with stoker/grate boiler).

Three non-BACT permits are also included in Table 5-3 for reference. Two required SCR systems for $NO_x$ control, but it appears they were voluntarily installed by the source. The first is for Burlington Electric

Department (Vermont), for which the permit limit is 0.075 lb/MMBtu, based on a RSCR system. The second determination was for Biomass Energy (Ohio), with a BACT limit of 0.088 lb/MMBtu, and was also based on SCR.

FBEnergy has been permitted with the lowest known $NO_x$ emission rate for a stoker/grate biomass-fired boiler (0.018 lb/MMBtu), with SCR as the control technology. This was not a BACT determination. Likewise, the lowest permitted emission rate for a fluidized bed boiler is Greenhunter Energy (CA), with a permitted limit of 0.014 lb/MMBtu, achieved with SCR (also a non-BACT determination).

***Identification of Potentially Applicable Control Technologies***

The BACT analysis was performed based on those available and feasible control technologies that can provide the maximum degree of emission reduction for $NO_x$ emissions. Emissions of $NO_x$ are produced by the high-temperature reactions of molecular nitrogen and oxygen in the combustion air (termed "thermal $NO_x$") and by fuel-bound nitrogen with $O_3$ (termed "fuel-bound $NO_x$"). The relative amount of each depends on the combustion conditions and the amount of nitrogen in the fuel. Formation of thermal $NO_x$ depends on the combustion temperature and becomes rapid above 1,400 degrees Celsius (°C) (2,550°F). The equations developed by Zeldovich are recognized as the reactions that form thermal $NO_x$:

$$N_2 + O \rightarrow NO + N$$
$$N + O_2 \rightarrow NO + O$$
$$N + OH \rightarrow NO + H$$

The important parameters in thermal $NO_x$ formation are combustion temperatures, gas residence time, and local stoichiometric ratio of fuel and air. Fuel-bound $NO_x$ is formed by the nitrogen in the fuel that reacts with combustion air. With some fossil fuels, such as natural gas or distillate fuel oil, emissions of fuel-bound $NO_x$ are usually small compared to thermal $NO_x$. However, fuel-bound $NO_x$ can be significant with fossil fuels such as No. 6 fuel oil and coal.

Another mechanism for $NO_x$ formation is the reaction of molecular nitrogen with free hydrogen (H) radicals. This mechanism is known as "prompt $NO_x$" and occurs within the combustion zone with the following major reactions:

$$N_2 + CH \rightarrow HCN + N$$
$$N + O_2 \rightarrow NO + O$$

The contribution of prompt $NO_x$ to overall $NO_x$ levels is relatively small (less than 5 percent).

The primary ways to reduce $NO_x$ emissions are through either combustion process controls or through catalytic or non-catalytic reactions.

Combustion controls are the primary engineering choice in reducing $NO_x$ concentrations within the boiler. Combustion controls include, but are not limited to, low-$NO_x$ burners (LNB) and overfire air (OFA). Such controls are considered "pollution preventing", because the formation of $NO_x$ is limited in the combustion process by reducing the peak temperature and reducing the residence time at peak temperature. A combustion technology referred to as "reburn" has also been installed as a retrofit technology on existing units to reduce $NO_x$ emissions (see description below).

Post-combustion $NO_x$ control processes include catalytic and non-catalytic conversion of $NO_x$, typically to nitrogen. Non-catalytic processes (e.g., SNCR) use ammonia ($NH_3$) or urea injection at high temperatures, generally about 1,800°F. These technologies can achieve from 50- to 60-percent $NO_x$ removal (depending on the fuel), and are primarily applicable to boilers that can maintain a relatively constant temperature for the reaction. Catalytic processes (SCR and RSCR) operate at lower temperatures (600 to 800°F) compared to SNCR processes. Recent developments in catalyst technology have lowered the operating temperature window to less than 500°F. These technologies can achieve up to 90 percent $NO_x$ removal. There are only a few SCR/RSCR processes actually operating on biomass-fired boilers at the present time.

**Removal of Nitrogen**

**Ultra-Low Nitrogen Fuel** – The fuels combusted in the bagasse boiler will be bagasse, wood, and natural gas. Combustion of these fuels results in emissions of $NO_x$ that are lower than other fuels, such as No. 6 fuel oil or coal, due to the characteristically low levels of nitrogen associated with these fuels. Among other things, HEF will control $NO_x$ emissions from the boiler through the use of low nitrogen content fuels.

**Oxidation of $NO_x$ with Subsequent Absorption**

**Inject Oxidant** – The oxidation of nitrogen to its higher valence states makes $NO_x$ soluble in water. When this is done, a gas absorber can be effective. Oxidants that have been injected into the gas stream are ozone, ionized oxygen, or hydrogen peroxide. This $NO_x$ reduction technique has not been demonstrated on large-scale boilers or with biomass combustion and, consequently, it is not considered technically feasible for the bagasse boiler.

**Non-Thermal Plasma Reactor (NTPR)** – This technique generates electron energies in the gas stream that generate gas-phased radicals, such as hydroxyl (OH) and atomic oxygen (O) through collision of electrons with water and oxygen molecules present in the flue gas stream. In the flue gas stream, these radicals oxidize $NO_x$ to form nitric acid ($HNO_3$), which can then be condensed out through a wet condensing precipitator. NTPR has not been demonstrated on large-scale boilers or with biomass combustion, and it is not considered technically feasible for the bagasse boiler.

**Chemical Reduction of $NO_x$**

**Selective Catalytic Reduction (SCR)** – A catalytic $NO_x$ removal process that has been demonstrated and proven is SCR, including regenerative SCR (RSCR). SCR is a widely used post-combustion $NO_x$-control technology that has been used on a variety of fuels (e.g., coal, natural gas, residual and distillate oil, and Orimulsion®) and applications (e.g., fossil steam units, combined-cycle units, diesel engines, and simple-cycle gas turbines). SCR has also been employed on at least two biomass-fired utility boilers.

Developing $NO_x$ control technologies include some processes that either combine the removal of various pollutants or specifically target the removal of $NO_x$. Such technologies, including Electro-Catalytic Oxidation™, $SO_x$-$NO_x$-$RO_x$ Box, and THERMALONOx™, have future promise but have not been demonstrated on large (> 100 MW) thermal power facilities. For this reason, they are not evaluated further in this application.

The fundamental reaction for SCR (i.e., the selective reaction of $NH_3$ with NO in the presence of a catalyst and excess oxygen) was discovered by Engelhard Corporation in 1957. SCR technology was commercially developed in Japan and used there on a continuing basis for the first time. In an SCR process, either anhydrous or aqueous $NH_3$ is injected into the flue gas upstream of a catalyst bed. The catalysts are arranged in modules set up into single or multiple stages. The selective reduction reactions occur at temperatures between 500 and 800°F on the surface of the SCR catalysts to produce molecular nitrogen gas and water. The reactions are as follows:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$
$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O$$

SCR catalysts consist of two types: base metal oxides and zeolite. In an SCR system using a base metal oxides catalyst, either vanadium or titanium is embedded into a ceramic matrix structure. The zeolite catalysts are ceramic molecular sieves extruded into modules of honeycomb shape. Different catalysts exhibit advantages and disadvantages in terms of exhaust gas temperatures, $NH_3/NO_x$ ratio, and exhaust gas $O_3$ concentrations for optimum control.

A common disadvantage for all catalyst systems is the limited temperature window where the $NO_x$ reduction process takes place. The reaction occurs typically between about 320 and 425°C (500 to 800°F). In recent years, catalyst manufacturers have been able to devise catalysts to lower the minimum operating temperature to about 500°F. These temperatures occur after the economizer of the boiler. Operating outside this temperature range results in failure to remove $NO_x$ and/or harm to the catalyst system. Chemical poisoning can occur at lower temperature conditions, while thermal degradation can occur at higher temperatures. Additional $NO_x$ emissions can be produced at higher temperatures. Reactivity can only be restored through catalyst replacement. Sufficient $O_2$ is required to ensure successful reactions. For most SCR applications that have been effective, $O_2$ concentrations have been in excess of 2 percent in the flue gas.

The SCR catalyst typically has a finite life. Some $NH_3$ typically slips through the catalyst without being reacted.

There are two types of SCR systems that potentially could be applied to the proposed HEF bagasse boiler: conventional SCR and "tail-end" SCR.

In a conventional SCR system, the catalyst is located just downstream of the boiler economizer, and upstream of the ESP. This location is necessary to operate in the appropriate temperature window for SCR (500 to 800°F). If this setup were used for the bagasse boiler, catalyst poisoning due to bagasse and wood combustion would occur because of the alkali content of the ash. Given the high PM loading in the flue gas prior to the ESP, premature catalyst deactivation would occur due to chemical poisoning of the catalyst. Based on an analysis of bagasse expected to be generated by HEF, with approximately 5 to 6 percent ash, the ash has an average of 0.5 percent sodium, 12 percent potassium, 5 percent phosphorus, 1.5 percent sulfur, and over 4 percent chlorides (all on a wet 50-percent moisture basis). Based on an analysis of wood ash from a facility similar to HEF, wood is approximately 9 to 10 percent ash, and has an average of 1.7 percent sodium, 4.0 percent potassium, 1.5 percent phosphorus, 2.0 percent sulfur, and over 1.3 percent chlorides. Based on these analysis, the potential for chemical poisoning and premature deactivation of the catalyst is very high and makes conventional SCR an inappropriate choice for $NO_x$ control on the bagasse boiler.

Technical difficulties are also expected with applying conventional SCR to the bagasse boiler because there is no operating SCR experience on bagasse. The high moisture content of the biomass (approximately 40 to 50 percent moisture) is also a concern for catalyst operation in a conventional SCR system. This could lead to catalyst fouling, reduced $NO_x$ removal efficiency, and failure of the system.

There currently is no known experience of conventional SCR installations on biomass-fired boilers. However, SCR has been placed on a few wood-fired boilers, as well as a number of MWCs in Europe, in a "tail-end" configuration. This type of installation allows the SCR to be placed downstream of all other pollution controls (particularly PM controls), reducing the potential for severe catalyst degradation or fouling due to the ash constituents. Although MSW and bagasse fired boilers do not produce similar ash, they both have the potential of catalyst poisoning and, therefore, conventional SCR is not feasible for biomass-fired boilers.

Until recently, tail-end SCR applications required reheating the flue gas from about 300-350°F up to the minimum operating temperature of the catalyst (i.e., 500°F). However, the required flue gas reheat, accomplished using a fossil fuel such as natural gas, was prohibitively expensive. Regenerative (RSCR) systems where then developed to minimize the amount of reheat required. Although the RSCR systems accomplished this goal, they still remained extremely expensive to install. RSCR however does have important applications for existing boilers, where the air heater cannot be relocated downstream of the PM air pollution control device.

As catalyst vendors continued to develop new low temperature catalysts, the need for flue gas reheat and RSCR was eliminated. Catalysts today are marketed as being able to operate at low temperatures, 500°F or less. For a new boiler, there is no longer a need to employ RSCR or flue gas heat, as the system can be designed from the outset with the air heater can be located downstream of the PM control device, where the lower temperature catalyst can be installed.

Although "tail-end" SCR is technically feasible with low temperature catalysts, it is emphasized there is limited experience with "tail-end" SCR installations on biomass-fired boilers. There are several such installations being permitted or undergoing construction at this time, as discussed above in the review of $NO_x$ BACT determinations. However, there is no experience on bagasse-fired boilers. For recent vendor quotes obtained for the proposed HEF bagasse boiler, vendors were only willing to guarantee the catalyst life for one (1) year.

A technology marketed by EmeraChem that is available for clean burning fuels such as natural gas and distillate fuel oil is EMx. According to the company, this technology is the next generation of SCONOx and is a multi-pollutant technology in a single system that significantly reduces $NO_x$, sulfur oxides ($SO_x$), CO, VOC, and PM for air emission requirements. The EPA declared this technology the lowest achievable emission rate (LAER) for $NO_x$ abatement.

EMx uses a catalyst for $NO_x$ and CO reduction. EMx is the most effective ammonia free reduction (AFR) technology available today for gas turbines, reciprocating engines, and industrial/utility boilers. EMx does not utilize $NH_3$. EMx has been in operation in excess of 7 years and contains durable, rugged, and robust system components. However, EMx has not been demonstrated on a biomass-fired boiler. Therefore, this technology is considered as not technically feasible. As with SCR, the potential fouling of the catalyst renders this technology infeasible for the bagasse boiler.

**Selective Non-Catalytic Reduction (SNCR)** – In an SNCR system, $NH_3$ or urea is injected within the boiler or in ducts downstream of the boiler in a region where the temperature is between 900 and 985°C (1,650 to 1,800°F). This technology is based on temperature ionizing the $NH_3$ or urea, instead of using a catalyst or non-thermal plasma. The temperature window for SNCR is very important because, outside of it, either (a) more $NH_3$ slips through the system or (b) more $NO_x$ is generated than is being chemically reduced. $NH_3$ slip has the potential to affect boiler operation as well as ammonium bisulfate formation on the downstream boiler components. SNCR has been applied to biomass-fired boilers for several decades, and the operating experience is robust. It is demonstrated as a feasible technology for biomass combustion and can achieve $NO_x$ reductions of 50 to 60 percent.

**Reducing Residence Time at Peak Temperature**

**Air Staging of Combustion** – In this system, combustion air is divided into two streams. The first stream is mixed with fuel in a ratio that produces a reducing flame. The second stream is injected downstream of the flame and creates an oxygen-rich zone. The bagasse boiler will utilize an OFA system, which acts as air staging of combustion.

**Fuel Staging of Combustion** – In this system, combustion is staged using fuel instead of air. Fuel is divided into two streams. The first stream feeds primary combustion that operates in a reducing fuel-to-air ratio. The second stream is injected downstream of primary combustion, causing the net fuel to air ratio to be slightly oxidizing. Excess fuel in the primary combustion zone dilutes heat to reduce temperature. The second stream oxidizes the fuel while reducing the $NO_x$ to nitrogen.

**Inject Steam** – Injection of steam causes the stoichiometry of the mixture to be changed and dilutes calories generated by combustion. These actions cause combustion temperatures to be lower, and in turn reduce the amount of thermal $NO_x$ formed.

Each of these techniques to reduce residence time at peak temperature is technically feasible.

**Reducing Peak Temperature**

**Flue Gas Recirculation (FGR)** – This technology involves recirculation of cooled flue gas back to the boiler, which reduces combustion temperature by diluting the oxygen content of the combustion air and by causing heat to be diluted in a greater mass of flue gas. Heat in the flue gas can be recovered by a heat exchanger. This reduction of temperature lowers the thermal $NO_x$ concentration that is generated. FGR is normally used to quench the flame, reducing both temperature and oxygen levels, thereby reducing the uncontrolled $NO_x$ emissions. However, it is difficult to maintain a flame temperature that is high enough in biomass boilers to maintain good combustion. It is likely that CO and organic HAP emissions would increase as a result of using FGR on a biomass boiler due to the lowering of the combustion temperature.

**Natural Gas Reburning** – The natural gas reburning process involves the introduction of natural gas into the burning zones of the boiler. The first zone is the primary combustion area where 80 to 85 percent of the fuel is burned. In this area, fuel is fired typically using the existing burner systems, which also can be LNBs. In the second zone, downstream of the primary combustion zone, remaining fuel is introduced to form a slightly fuel rich combustion zone. This area is often referred to as the reburn zone, where hydrocarbon compounds are formed that react with nitrogen oxide, the primary form of $NO_x$ in combustion processes. The reactions of these hydrocarbon radicals and nitrogen oxide ultimately form nitrogen, which therefore inhibits the $NO_x$ formation process (i.e., Zeldovich reaction). The third zone, downstream of the reburn zone, is often referred to as the burnout zone where combustion air is added to combust the remaining hydrocarbon compounds. The overall combustion process is typically fuel lean. This technology requires no catalysts, chemical reagents, or changes to any existing burners. Typical reburn systems also incorporate redesign of the combustion air system to provide less excess air (LEA).

Reburn has been demonstrated using natural gas, coal, residual oil, and Orimulsion®. Reductions in $NO_x$ from 40 to 70 percent have been demonstrated with this wide variety of fuels. For the bagasse boiler, natural gas reburn is a feasible technology. However, a reburn system would require displacement of 20 percent of the biomass with natural gas, while resulting in, at best, a 25 percent reduction of $NO_x$ emissions.

**Over-Fire Air (OFA)** – When primary combustion uses a fuel-rich mixture, use of OFA completes the combustion. Because the mixture is always off-stoichiometric when combustion is occurring, the combustion temperature is reduced. After all other stages of combustion, the remainder of the fuel is oxidized in the OFA zone. The bagasse boiler will utilize an OFA system to promote vigorous mixing of the combustion gases to maximize combustion efficiency and reduce pollutant emissions. The OFA system injects hot air at high velocities into the furnace.

Advanced OFA systems have been developed and marketed by several companies. There are several novel OFA systems being offered on the market today which are applicable to biomass-fired stoker boilers. All attempt to improve air/fuel mixing and turbulence in the furnace, while maximizing gas residence time. Cold spots are reduced, and more complete carbon burnout is accomplished. Two of these systems, which have some experience on biomass-fired boilers, are described below.

**Nalco Mobotec** – ROFA® (Rotating Opposed Fire Air) is Nalco Mobotec's patented design that sets the volume of combustion gases in the furnace in rotation via an asymmetric boosted OFA system. The induced rotation and turbulence prevent laminar flow, resulting in superior mixing and temperature distribution, for more effective combustion. Staging the combustion allows for optimal emissions control, inducing reduction of $NO_x$, CO, and PM, while minimizing excess air and unburned carbon in the fly ash. This system has demonstrated significant $NO_x$ reductions, with lower reagent use or no need for a reagent. ROFA also allows for the flexibility to fire various fuels or co-fire biomass. ROTAMIX® is a patented technique for rotary mixing of chemicals and/or additional fuel in the ROFA system. The system combines air injection nozzles with automatically regulated lances for the injection of chemicals into the furnace where the temperature is most favorable. Combined with ROFA, the ROTAMIX system can reduce $NO_x$ emissions. Additionally, demand for chemicals is reduced, when compared to other SNCR systems.

**Synterprise EcoJet** – EcoJet is marketed as an advanced OFA combustion system. The company claims the system will provide the following benefits:

- Reduced Fuel Use – EcoJet reduces the use of fuel operating costs with improved combustion completion. The EcoJet System's unique high energy variable direction, variable flow tuning capabilities provide dramatically improved mixing and distribution of fuel in the flue gas. The EcoJet System breaks up the laminar flow present in almost all biomass boilers by using high pressure, low volume, variable flow air nozzles. The EcoJet System re-circulates the gas stream in the furnace, finishing combustion, reducing gas velocity, improving distribution, reducing particulate carry over, and reducing total mass gas flow, while providing temperature control in the upper furnace. The EcoJet System reduces fuel use and erosion accelerated damage to water walls and convection pass elements, as well as related damage in downstream components.
- Increased Steam/Power Generation Revenues – The EcoJet System is designed to improve the mixing of combustion air, partially burned gases, and fuel while decreasing total mass flow and reducing velocities. Increased turbulence, increased time, and improved temperature management increase furnace efficiencies and result in increased steam generation. The EcoJet System overcomes poor combustion conditions caused by wet fuel, lower quality fuel, high CO, and other poor combustion conditions, resulting in a much more stable combustion state that allows recovery of previously lost generation from wet fuel or high CO conditions. Using advanced separated OFA staged combustion improvement processes, the EcoJet System improves combustion completion, increases steam generation, and reduces particulates, ash and erosion. By decreasing fuel use (3 to 10 percent), increasing steam generation/power sales revenue (3 to 10 percent), and by lowering erosion, particulates, ash and related maintenance costs, the EcoJet System provides a quick return on investment.
- $NO_x$, CO, VOC, and PM Emission Reduction – The EcoJet System provides emissions reductions. For example, $NO_x$ emissions can be reduced by the unique advanced, staged separated OFA process using staged combustion while optimizing CO and particulate carry over. The EcoJet System completes the combustion process, stabilizing CO, allowing reductions in total air and excess air, thus reducing $NO_x$ formation from 20 to 50 percent, and can reduce, or eliminate, the use of reagents to meet emission regulations. The EcoJet System can reduce $NO_x$ emissions an additional 30 to 40 percent by injecting reagents such as urea, aqueous $NH_3$, or anhydrous $NH_3$.

Both Nalco Mobotec and Synterprise have indicated the ability to achieve 0.21 lb/MMBtu $NO_x$ without SNCR, and 0.14 lb/MMBtu with SNCR, on bagasse-fired boilers similar to the proposed HEF boiler.

**Less Excess Air (LEA)** – The amount of excess air in the combustion zone has been correlated to the amount of $NO_x$ generated. Limiting excess air to the boiler can limit the $NO_x$ content of the flue gas. However, low excess air cannot be used when burning a high moisture biomass fuel in suspension because the reduced combustion air flow will cause the fuel to pile on the grate. This is problematic due to the variability of the biomass and the difficulty in consistently maintaining ideal combustion conditions.

**Combustion Optimization** – Combustion optimization refers to the active control of combustion by measuring boiler oxygen level, combustion zone temperature, etc., and adjusting boiler operating parameters in response. The active combustion control measures seek to find optimum combustion efficiency and to control combustion at that efficiency. The bagasse boiler will be optimized for maximum combustion efficiency, and boiler operating parameters will be continuously monitored (see Section 2.0). However, the nature of the bagasse fuel may result in continuous changes to optimization points.

**Low $NO_x$ Burners (LNB)** – An LNB provides a stable flame that has several different burning zones. For example, the first zone can be primary combustion; the second zone can be Fuel Reburning (FR) with fuel added to chemically reduce $NO_x$; and the third zone can be the final combustion in low excess air to limit the temperature. LNB is not an option for a biomass-fired system with pneumatic distributors for fuel feed, because fuel in this system is injected into the furnace above the grate. Lighter particles, such as bagasse, burn in suspension, and the heavier particles, such as wood, fall to the grate. It is also not applicable to a fluidized bed boiler.

LNBs can be employed for propane and fuel oil firing. These type burners will be utilized on the bagasse boiler.

***Evaluation of Technically Feasible Control Alternatives***

The technically feasible $NO_x$ controls for the bagasse boiler are listed in Table 5-4. As shown, there are five types of $NO_x$ abatement methods with various techniques for each method. Each available technique was listed with its associated efficiency estimate, identified as feasible or infeasible, and ranked based on control efficiency. Tail end SCR, SNCR, combustion controls, and using ultra-low nitrogen fuel are the initial choices for reducing $NO_x$ from the combustion process. Most recent permits issued for biomass boilers have required the use of combustion controls, combined with SNCR, to control $NO_x$ because these controls are generally available, technically feasible, well proven, and provide the maximum degree of emission reduction. SCR and RSCR have had limited application to biomass-fired boilers.

***Ranking of Technically Feasible Control Alternatives***

SCR/RSCR, SNCR, and reducing the residence time at peak temperatures are highly effective in controlling $NO_x$ emissions and will achieve the maximum degree of $NO_x$ emission reduction. As shown in Table 5-4, RSCR and SCR have an estimated $NO_x$ removal efficiency of 75 percent, SNCR has an estimated $NO_x$ removal efficiency of 50 to 60 percent, and reducing residence time at peak temperatures has an estimated $NO_x$ removal efficiency of 50 to 65 percent. Reducing peak temperatures provides an efficiency of 15 to 25 percent. Advanced OFA systems employ a combination of these methods to achieve $NO_x$ reduction. Other technologies have not demonstrated equivalent levels of control for $NO_x$.

***Evaluation of Economic, Environmental, and Energy Impacts of Feasible Technologies***

***Economic Impacts***

The top ranked technically feasible control technologies, as shown in Table 5-4, are RSCR and SCR. RSCR does not have any cost advantage over SCR (due to RSCR's fuel costs), and RSCR does not achieve any lower emissions than SCR. Therefore, a cost analysis for "tail-end" SCR only was prepared, based on recent cost quotes. This cost analysis is presented in Appendix J, as a component of a larger overall quote for a complete air pollution control system.

The cost analysis is summarized in Tables 5-5 and 5-6, and cost effectiveness values are shown. Where feasible, costs for a complete package were estimated, due to cost savings that can be realized by procuring control equipment through a single vendor. Therefore, the cost of a particular control technology must be estimated based on the differences in complete packages. As shown, the estimated installed capital cost of SCR is $3.7 million. The total annual costs are estimated at $780,000 per year. Based on the estimated 70 percent reduction in $NO_x$ emissions (reduction of 322.5 TPY at 8,040 hr/yr operation), the total cost effectiveness is $2,418 per ton of $NO_x$ removed.

The next most effective add-on $NO_x$ control technology is SNCR. Because HEF is proposing to utilize SNCR for $NO_x$ control on the bagasse boiler, a detailed cost analysis is not required. However, to allow comparison to the SCR system costs and to determine incremental cost effectiveness, a cost estimate for SNCR was developed. This cost is presented in Appendix J, based on a quote from a leading SNCR vendor. As shown, the estimated capital cost of SNCR is approximately $2.0 million. The total annual costs are estimated at 650,000 per year. Based on the estimated 60 percent reduction in $NO_x$ emissions, the total cost effectiveness is $2,351 per ton of $NO_x$ removed.

Based on these cost analyses, the incremental cost effectiveness of SCR over SNCR can be estimated. This is shown in Table 5-6. The SCR system annual cost is approximately $130,000 greater than SNCR costs, while the SCR system will control an additional 46 TPY of $NO_x$ emissions. The incremental cost effectiveness of SCR over SNCR is therefore $2,821 per ton of $NO_x$ removed. The cost of SCR is high for only a small incremental reduction in $NO_x$ emissions.

Two enhanced OFA systems, Nalco Mobotec and Synterprise, were not evaluated for economic impacts, as these systems do not achieve any lower $NO_x$ levels, i.e., vendor quotes received included guarantees of 0.10 lb/MMBtu $NO_x$ with SNCR.

Natural gas reburning, although technically feasible, would be very costly to operate. A reburn system would require displacement of 20 percent of the biomass with natural gas (approximately 820,000 MMBtu/yr), which would result in a natural gas cost of approximately $5.7 million per year (at $7/MMBtu), while resulting in, at best, a 25-percent reduction of $NO_x$ emissions.

***Environmental***

No additional significant environmental impacts from either SCR or SNCR technology are anticipated. SCR requires disposal of the catalyst every year. SNCR uses water (with the ammonia), while the SCR does require natural gas usage. The electrical energy required to operate either the SNCR or the SCR systems is approximately the same, about 35 kW.

***Energy***

Energy penalties occur with SNCR and SCR. SNCR will require inputs of energy, water, and ammonia. SCR requires energy, natural gas, and $NH_3$. Energy is required to maintain the flue gas stream at the appropriate temperature for catalyst operation. There will also be a loss in efficiency of the boiler with SNCR due to the injection of an aqueous stream and subsequent evaporation in the boiler.

***Selection of BACT and Rationale***

The identification, technical evaluation, and ranking of the available control technologies indicate that combustion controls and SCR or SNCR provide the maximum degree of $NO_x$ emission reduction. The evaluation of the energy, environmental, and economic impacts demonstrates that SCR is extremely costly. At approximately $3.7 million, the SCR system would cost approximately 15 percent of the cost of the entire bagasse boiler. The SCR would result in only marginal reductions in $NO_x$ emissions (46 TPY) compared to SNCR, resulting in an incremental cost of over $2,800 per ton of $NO_x$ removed. This cost is high. In additional, a similar renewable fuels/ethanol plant (Highlands Ethanol LLC) was recently issued a final PSD permit by FDEP based on SNCR, and was not required to utilize SCR.

In addition, there is limited operating experience with SCR systems on biomass-fired boilers, and no operating experience on bagasse-fired boilers. Therefore, additional costs could be incurred as a result of unforeseen problems encountered with the system.

It is also noted that the SCR vendor is only guaranteeing the catalyst life to be one year, arguably based on lack of experience of this equipment with biomass in general and sweet sorghum bagasse in particular. Also, several vendors were asked to provide a list of experience with SCR projects. Based on the vendor's responses, they have no operating experience utilizing SCR on a biomass-fired boiler, let alone on bagasse. We understand one vendor is currently constructing an SCR system on a wood-fired boiler in Texas; however it is not yet operational.

The additional costs imposed by SCR could potentially render the project infeasible based on economic impacts. Lending institutions are not willing to lend significant amounts of capital for unproven technology configurations. At the very least, SCR would put HEF at a significant cost disadvantage compared to Highlands Ethanol and Southeast Renewable Fuels, which will be producing the exact same product as HEF – ethanol from biomass- but without having to bear this additional cost.

For all these reasons, SCR is rejected as BACT for $NO_x$ emissions for the bagasse boiler. [Notwithstanding this determination, HEF proposes to leave necessary space for the installation of a $NO_x$ catalyst at some time in the future, if SCR becomes more technically proven and more cost effective].

The next most effective $NO_x$ control technology, SNCR, along with advanced combustion design and controls, is selected as BACT for the bagasse boiler. SNCR is feasible and reasonable based on the economic, environmental, and energy impacts. A $NO_x$ emission rate of 0.10 lb/MMBtu, 30-day rolling average, is proposed as BACT for the bagasse boiler. This limit is equal to the recent BACT determination for Southeast Renewable Fuels, LLC, for its spreader stoker boiler design.

As stated previously, the primary goals of the HEF project are as follows:

- Generating steam and electricity from a renewable resource
- Generating "green" jobs in Florida, in lieu of purchasing out-of-state fossil fuels
- Reduction in GHG emissions due to the use of annually renewable fuels
- Accomplishing the above while remaining economically viable

The selection of SNCR as BACT for $NO_x$ is consistent with these goals

As noted previously, HEF will be uniquely tied to an agricultural operation and thus subject to weather conditions as well as shifts in agricultural commodity prices. The price of ethanol, the primary product of the facility, will be subject to fluctuation in the future. The electricity provided to the electric grid by the facility will be sold through a power purchase agreement, which is fundamentally different than a dedicated electric utility power plant, which solely generates electricity for sale to the grid (no steam cogeneration). All of these aspects of the project render the HEF project fundamentally different than an electric utility boiler, in operation and in economics.

HEF is concerned that its project may be compared to other dissimilar biomass projects, rather than the U.S. Sugar Boiler No. 8 which is the most recently installed bagasse boiler in the state of Florida. U.S. Sugar Boiler No. 8 is directly comparable to HEF's proposed boiler. Boiler No. 8 burns bagasse with high moisture content (50 to 55 percent), and employs SNCR, which is now well proven on bagasse boilers. Sweet sorghum bagasse and sugar cane bagasse will similarly have a high moisture content (50 to 55 percent). Like U.S. Sugar Boiler No. 8, HEF will combust bagasse, not low-moisture stillage. Boiler No. 8 was permitted several years ago. HEF has proposed lower $NO_x$ limits compared to Boiler No. 8. However, the strongest factor for comparative analysis of comparable facilities should be the relevant feedstock and conversion technology.

Conversely, the following is a list of other facilities that FDEP may use as a comparison to HEF. All these facilities, except for Highlands Ethanol (Verenium) and Southeast Renewable Fuels, are significantly distinguishable from HEF as follows:

- FBEnergy – FBEnergy is a minor PSD source and not subject to BACT; therefore, this was not a BACT determination. This is a wood-fired facility, which is a fuel much different than bagasse (in terms of moisture content, 30-50 percent, and other constituents), and for which a great deal of information is available (in terms of constituents such as ash and chemical constituents, and how they vary over time). FBEnergy sought to obtain a permit for a facility that could be built anywhere in the country, including nonattainment areas.

Therefore, they voluntarily proposed SCR. SCR also was proposed in order to avoid being a major source of HAPs, which would require a case-by-case MACT analysis. This is also purely a power production facility, with economics much different than HEF. This facility is not a valid comparison to HEF.

- ADAGE – Adage is a minor PSD source and not subject to BACT; therefore, this was not a BACT determination. ADAGE proposed a bubbling fluidized bed boiler, which is fundamentally different that HEF's suspension/grate boiler. This is also a wood-fired facility and a large power production facility (much larger boiler), with economics much different than HEF. Adage voluntarily proposed SCR, in part to avoid being a major source of HAPs and case-by-case MACT review. This facility is a not valid comparison to HEF
- American Renewables – American Renewables (GRU) is a major PSD source and subject to BACT.. GRU proposed a bubbling fluidized bed boiler, which is much different than HEF's suspension/grate boiler.. This is also a wood-fired facility and a large power production facility (with much larger boiler), with economics much different than HEF. GRU voluntarily proposed SCR as BACT. This facility is not a valid comparison to HEF
- Geoplasma – The Geoplasma project will utilize plasma-arc technology to gasify municipal solid waste producing a low Btu syn-gas. Due to the nature of this project, they must obtain a permit prior to getting financing. This plant will more than likely never be built, based on economics. This facility is not a valid comparison to HEF.
- Ineos – The Ineos project is another gasifier project. This facility is not a valid comparison to HEF.
- Highlands Ethanol – Highlands Ethanol provides the closest comparison to HEF's project, except that Highlands Ethanol proposed a bubbling fluidized bed boiler. SNCR was proposed by Highlands Ethanol, rather than SCR, and oxidation catalyst was not required; this was accepted by FDEP for the Highlands Ethanol permit. Accordingly, HEF requests the same treatment.

  Highlands Ethanol, in their application, specified a fluidized bed boiler and SNCR to achieve a $NO_x$ limit of 0.075 lb/MMBtu. FDEP, in their permit, specified 0.075 lb/MMBtu (exactly what Highlands Ethanol had proposed), which could be met through either SNCR or SCR. But SCR was not required by the permit, and SCR is not necessary to meet the permit limit.

  Highlands Ethanol's permit clearly states that they generate their own process steam by combusting biomass with stillage cake (as low as 35 percent moisture) being their primary fuel and tree wood chips/bagasse/or energy crop material listed as supplemental boiler fuel. Combusting stillage from these type components is not a proven technology on a commercial scale, with the exception of perhaps a few corn ethanol plants. FDEP has recognized this as shown by the following statement in the Highlands Ethanol permit addressing a question from EPA: "*The [backup boiler] operation will be progressively reduced as the cellulosic manufacturing process and associated biomass combustion technologies are proven*". Just as FDEP recognized that burning ethanol stillage is not commercially proven, so too, FDEP should recognize that certain technologies for combustion of sweet sorghum bagasse and sugar cane bagasse are similarly not proven. SCR applied to sweet sorghum bagasse (or any type bagasse) is unproven. HEF cannot commit to limits with equipment that is not proven.

  In the TE&PD for the Highlands Ethanol final permit, FDEP states:

  > *The applicant proposes to achieve its proposed BACT NOX 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 NOx (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 NOX 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 Highlands Ethanol pilot and demonstration plants in Jennings, Louisiana.*

*Based on the foregoing discussion, the Department will set a limit of 0.075 lb NOx/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).*

HEF's project is basically the same as this, except that sweet sorghum bagasse and sugar cane bagasse will be burned instead of stillage. One other proposed ethanol/cogeneration facility (Southeast Renewable Fuels) has tested sweet sorghum for various constituents, and has conducted a trial burn with a combination of sweet sorghum and sugarcane bagasse. The trial burn was very successful, and the sweet sorghum did not alter the character of emissions compared to burning sugarcane bagasse alone. There are no significant questions regarding sweet sorghum and the operation of the control technologies that SRF has proposed. There are, however, significant questions with the operation of an SCR or RSCR system on bagasse (sugarcane or sweet sorghum), because such systems have never been used or demonstrated on a bagasse-fired boiler. This lack of operating experience with SCR/RSCR was a major factor in the Highlands Ethanol BACT determination, and is a major factor for HEF.

Highlands Ethanol's $NO_x$ limit for the fluidized bed boiler (0.075 lb/MMBtu) is slightly lower than that proposed by HEF (0.10 lb/MMBtu), due to the selection by HEF of the hybrid suspension grate technology, which is well proven for bagasse. However, this limit proposed by HEF would not require HEF to use SCR to meet the $NO_x$ limit. It would not be appropriate to require HEF to bear the cost of an SCR or RSCR system, especially since there is no operating experience on bagasse. This would also put HEF at a significant cost disadvantage compared to Highlands Ethanol, which will be producing the exact same product as HEF- ethanol from biomass.

- Southeast Renewable Fuels – The permit was issued to SRF just in December 2010. Two $NO_x$ limits were set, one for the BFB boiler (0.08 lb/MMBtu) and one for the spreader stoker boiler (0.10 lb/MMBtu). The limit can be met with either SCR, SNCR, or a combination of the two. HEF requests the same permit requirements, i.e., a limit of 0.10 lb/MMBtu based on the hybrid suspension/grate boiler, which can be met by either SNCR, SCR, or a combination.

The NSPS Subpart Db contains $NO_x$ emission standards for fossil fuel firing. There are no specific standards for wood firing; however, when burning fuel oil in combination with wood, the applicable standard for natural gas firing alone must be met. The applicable standard for natural gas firing, for units for which construction commenced after July 9, 1997, is 0.20 lb/MMBtu. However, there is an exemption from this standard provided that fossil fuel firing does not exceed a 10 percent annual capacity factor for the unit [40 CFR

60.44b(l)(1)]. Nevertheless, the bagasse boiler will meet the BACT limit of 0.10 lb/MMBtu when firing any fuels, either alone or in combination.

### *5.4.3 Sulfur Dioxide ($SO_2$)*

***Previous BACT Determinations***

A review was performed of previous $SO_2$ BACT determinations for similar biomass-fired industrial and electric utility boilers listed in the RBLC on EPA's web page. A summary of these BACT determinations is presented in Table 5-7. Only determinations issued within the last 10 years are shown (i.e., since 2001).

Previous BACT determinations have ranged from 0.02 to 1.54 lb/MMBtu $SO_2$. Four of the determinations were for bagasse-fired boilers, and BACT limits ranged from 0.06 to 0.20 lb/MMBtu $SO_2$ (depending on averaging time). Bagasse is a fuel that exhibits lower and less variable sulfur content than wood. Six projects were located at paper mills, which predominantly obtain biomass from dedicated forests, with a consistent fuel quality.

It is noted that the Grayling Generating Station determination listed is likely not a BACT determination, because total $SO_2$ emissions from the plant were less than 40 TPY. In addition, several non-BACT determinations are included in Table 5-7. These are provided due to their similarity to the HEF project.

From the review of these previous BACT determinations, it is evident that $SO_2$ BACT determinations for biomass-fired boilers have been based solely on fuel specifications (i.e., use of low sulfur-containing fuels). Therefore, the emission limits are based on the prospective fuel supply. This is undoubtedly due to the very low sulfur content of biomass fuels. Note that the recent determination for S.D. Warren Co. was for a boiler located at a paper mill that fires bark, wood, sludge, No. 6 fuel oil, tire-derived fuel, and waste oil. Thus, this boiler is not a primarily biomass-fired boiler.

***Identification of Potentially Applicable Control Technologies***

Sulfur compounds are produced in boilers firing fossil fuels by the combustion process in which complete oxidation of the fuel-bound sulfur occurs, forming primarily $SO_2$, with smaller quantities of $SO_3$. The amount of $SO_2$ emissions is directly proportional to the sulfur and sulfate content in the fuel. Reducing $SO_2$ emissions by boiler modification is not feasible because combustion processes do not affect $SO_2$ emissions. Generally, complete oxidation of sulfur in fuel is readily achieved before complete combustion of carbon, the most abundant element in fossil fuel. Potentially applicable control technologies are listed in the following subsections.

**Sorbent Injection**

Sorbent injection involves the injection of a dry sorbent into the furnace, economizer, or in the flue gas duct after the air preheater, where the temperature is about 300°F or less. In furnace injection, a finely grained sorbent, limestone ($CaCO_3$) or hydrated lime [$Ca(OH)_2$], is distributed quickly and evenly over the entire cross section in the upper part of the furnace in a location where the temperature is in the range of 1,400 to 2,300°F. The sorbent reacts with $SO_2$ and $O_2$ to form calcium sulfate ($CaSO_4$). $CaSO_4$ is then captured in a particulate control device together with unused sorbent and fly ash. Temperatures over 2,300°F result in sintering of the surface on the sorbent, destroying the structure of the pores and reducing the active surface area.

In an economizer sorbent injection system, $Ca(OH)_2$ is injected into the flue gas stream near the economizer zone where the temperature is in the range of 600 to 1,200°F. At this temperature, $SO_2$ reacts with the sorbent to form calcium sulfite ($CaSO_3$).

In duct sorbent injection, the aim is to distribute the sorbent evenly in the flue gas duct after the air preheater, where the temperature is 300°F or less. At the same time, the flue gas is humidified with water. As with the furnace and economizer designs, the end products are collected in a particulate control device.

There are many factors that influence the performance of a duct sorbent injection process. These include sorbent reactivity, quantity of injected sorbent, relative humidity of the flue gas, gas and solids residence time in the duct, and quantity of recycled, unreacted sorbent from the particulate control device. The most efficient way of achieving good conditions is to establish a dedicated reaction chamber.

**Wet Flue Gas Desulfurization**

Devices that are based on absorption principles include packed towers, plate columns, venturi scrubbers, and spray chambers. Absorption is a mass transfer operation in which one or more soluble components of a gas mixture are dissolved in a liquid that has low volatility under the process conditions. The pollutant diffuses from the gas into the liquid when the liquid contains less than the equilibrium concentration of the gaseous component. The difference between the actual and the equilibrium concentration provides the driving force for absorption.

Wet flue gas desulfurization (FGD) systems include three different types, which are classified by the reagents used in the scrubbing process. The type of reagent influences the scrubber design, the quantity and type of wastes produced, and the type of disposal system required. Sodium-based, calcium-based, or dual-alkali-based chemicals are used; these systems are referred to as sodium-based, wet lime/limestone scrubbers, or dual-alkali. Each of these systems creates solid and liquid waste streams, which must be treated before disposal.

The sodium scrubbing systems use either a sodium hydroxide (NaOH) or a sodium carbonate ($Na_2CO_3$) wet scrubbing solution to absorb $SO_2$ from the flue gas. Because of the high reactivity of the sodium alkali sorbent compared to the lime or limestone sorbents, these systems are characterized by a low liquid-to-gas ratio. The $SO_2$ gas reacts with the hydroxide or carbonate to form sulfite (e.g., $Na_2SO_3$)

initially, then sulfate ($Na_2SO_4$) with further oxidation. Both sodium sulfite and sulfate are highly soluble; therefore, the final scrubber effluent is a mixture of sodium alkaline salt liquor that requires special disposal. Although these sodium-based systems are capable of achieving greater than 90-percent $SO_2$ reduction, they have not been used commercially on large boilers; therefore, these systems are considered unproven.

The dual-alkali scrubbing process uses the sodium-based liquor to scrub the $SO_2$ from the flue gas initially, and then calcium-based chemicals are used to regenerate the sodium hydroxide or $Na_2CO_3$ solution. Both the sodium-based and the dual alkali-based scrubbing systems were developed many years ago to address the inherent fouling problem that was often experienced with conventional lime/limestone wet scrubber systems. It was believed that the sodium-based or the dual-alkali-based systems could achieve higher percentage removal of $SO_2$ due to higher reactivity. The primary reasons for not using the sodium-based system are the cost of premium chemicals, the lack of availability of sodium-based chemicals, the highly alkaline waste liquid produced, and lack of boiler experience.

The sodium-based and the dual-alkali-based scrubbing processes are no longer commercially available from the primary supplier, FMC Corporation. Other suppliers of the sodium-based or dual-alkali-based systems, Ontario Hydro and General Electric Environmental Systems, no longer recommend these systems to control boilers over the improved lime/limestone wet scrubber.

Because neither the sodium-based scrubber nor the dual-alkali scrubber system has been installed in many years, these technologies are generally considered unavailable.

A new sodium bicarbonate scrubbing process, referred to as The Airborne Process, has entered the commercial market following 5 years of extensive research and development. The Airborne Process is a multi-pollutant control system ($SO_2$, $NO_x$, and Hg) that uses dry sodium bicarbonate injection coupled with enhanced wet sodium bicarbonate scrubbing to provide pollutant controls. The resulting by-products are ammonium sulfate and potassium sulfate that can be further processed by the vendor's patented granulation process. Although this process has lower operating costs than currently available technologies and creates a new profit stream through the production of commercial fertilizer by-products, it has only been demonstrated with coal. Because this system has not been demonstrated on biomass, it is considered infeasible for this application.

The most widely used system for large-scale $SO_2$ removal is the calcium-based wet lime/limestone FGD system. Depending on whether lime or limestone is used, the $SO_2$ reacts with the hydrates or carbonates to form calcium sulfite (i.e., $CaSO_3 \cdot \frac{1}{2}H_2O$) initially, then sulfate (i.e., $CaSO_4 \cdot 2H_2O$) with further oxidation. The latter, known as wet limestone-forced oxidation FGD, involves blowing air into the slurry to force oxidation to calcium sulfate of almost 100 percent. This produces a marketable by-product (i.e., gypsum).

$SO_2$ control efficiencies for wet limestone FGD range from 50 to 98 percent, depending on the type of device and design, with an average of 90 percent.

One version of the wet FGD technology is the spray tower. In this system, a slurry of atomized limestone is sprayed into a tall, vertical absorber tower through a series of nozzles. The flue gas enters at the bottom of the tower, passes vertically up through the spray droplets, and exits the vessel at the top to be recirculated back through the absorber system, which increases the scrubbing utilization of the limestone reagent. The scrubbing reaction produces $CaSO_3$ as the byproduct. Most systems oxidize the $CaSO_3$ into $CaSO_4$, which is easier to dewater. A bleedstream is taken off from the recycled slurry stream to purge the system of gypsum and avoiding buildup inside the spray tower. By-products and unreacted reagents in the bleedstream are dewatered using various equipment including thickeners (hydroclones), centrifuges, and vacuum filters. Dewatering can reduce the water content in the filtered by-product to as low as 10 to 15 percent by weight.

Development of the spray tower limestone FGD system operating at high liquid-to-gas ratios has produced levels of $SO_2$ removal as high as those of the dual-alkali-based system. Improved operating techniques have also eliminated the severe fouling problems experienced by the earlier lime/limestone scrubber systems.

Wet scrubbing systems can use lime rather than limestone as the alkali reagent. Quicklime (CaO) is slaked with water to form $Ca(OH)_2$. The slurry of $Ca(OH)_2$ and water is then sprayed into the spray tower. This alternative of using lime instead of limestone is less attractive economically because the cost of either CaO or $Ca(OH)_2$ is much higher than the cost of limestone. While a limestone system requires more initial capital costs for auxiliary equipment (i.e., limestone ball mill and conveyors), the lower operating cost of the reagent provides a substantial annual savings for wet limestone FGD systems over the use of lime.

In conventional wet limestone FGD systems, several additives have been used to enhance $SO_2$ removal efficiencies. The majority of additives, both organic and inorganic, have been used to bring the performance of the FGD system up to the original performance requirements. The organic additives include various mixtures of organic acids that include dibasic acid and formic acid. Magnesium, added as magnesium-lime, has been successfully used to enhance performance. With the advancement of wet FGD designs, efficiencies of 98 percent can be achieved by refinements in design including critical elements of absorbers, materials, and control systems. Additives can still play a role, but their use is primarily focused on emergency condition operation, corrosion inhibition, scaling, and by-product handling.

**Spray Dryer FGD**

In a dry FGD process, the flue gas entering the scrubber contacts an atomized slurry of either wet lime or wet $Na_2CO_3$ sorbent. The exact mechanisms for the absorption of gaseous $SO_2$ and the formation of alkaline salts are complex. Overall, the $SO_2$ gas reacts with lime or sodium sorbent to initially form either calcium sulfite ($CaSO_3 \cdot ½H_2O$) or sodium sulfite ($Na_2SO_3$). Upon further oxidation or $SO_2$ absorption enhanced by the drying process, the sulfite salts transform into calcium sulfate ($CaSO_4 \cdot 2H_2O$) or sodium sulfate ($Na_2SO_4$) solids. A typical dry scrubber will use lime as the reagent because it is more readily available than sodium carbonate and the sodium-based reactions produce a soluble by-product that requires special handling.

Lime slurry is injected into the dry scrubber chamber through either rotary atomizers or pressurized fluid nozzles. Rotary atomizers use centrifugal energy to atomize the slurry. The slurry is fed to the center of a rapidly rotating disk or wheel where it flows outward to the edge of the disk. The slurry is atomized as it leaves the surface of the rapidly rotating disk.

Fluid nozzles use kinetic energy to atomize the slurry. High-velocity air or steam is injected into a slurry stream, breaking the slurry into droplets, which are ejected at near-sonic velocities into the spray-drying chamber. Slurry droplets of comparable size can be obtained with both fluid nozzles and rotary atomizers, minimizing differences in performance due to atomizer type. The nozzle location relative to the flow, however, can be different depending on the particular design.

The moisture in the lime slurry evaporates and cools the flue gas, and the wet lime absorbs $SO_2$ in the flue gas and reacts to form liquid-solid phase salts that are then dried into insoluble crystals by the thermal effect of the flue gas. The dry scrubber chamber is designed to provide sufficient contact and residence time to complete this reaction process. The residence time in the chamber is typically designed for 10 to 15 seconds. Sufficient contact between the flue gas and the slurry solution is maintained in the absorber vessel, allowing the absorbing reactions and the drying process to be completed.

The particulates exiting the dry scrubber contain fly ash, dried calcium salts, and dried unreacted lime. The moisture content of the dried calcium salt leaving the absorber is about 2 to 3 percent, eventually decreasing to about 1 percent downstream. The simultaneous evaporation and reaction in the spray drying process increases the moisture and particulate content of the flue gas and reduces the flue gas temperature.

In the dry scrubber, the amount of water used is optimized to produce an exit stream with "dry" particulates and gases with no liquid discharge from the scrubber. Because the water is completely evaporated in the system, wastewater treatment is not needed. The flue gas temperature exiting the dry scrubber is typically 18 to 30°F above adiabatic saturation, which refers to no heat gain or loss to the surroundings. To remove the "dry" reaction products from the flue gas, the spray dry scrubber must be followed by a highly efficient PM control device, which is typically a fabric filter (baghouse), although an ESP could also be used. Use of a baghouse instead of an ESP has some advantages when using a dry scrubber FGD system because the baghouse provides additional $SO_2$ and acid gas removal. When a baghouse is used, a layer of porous filter cake is formed on the surface of the filter bags. This filter cake contains unspent reagent, which provides a site for additional desulfurization since the flue gases must pass through the filter bags.

$SO_2$ removal efficiency for lime spray drying ranges from 70 to 96 percent, with an average of 90 percent. The use of a PM control device after the dry scrubber differs from the wet scrubber system, in which the slurry leaving the wet system must be dewatered and the gas cooled to adiabatic saturation temperature, which requires the particulate control device to be located upstream of the scrubber. The dry byproduct from the dry scrubber system is generally not marketable, since the byproducts includes fly ash and reacted $SO_2$ and calcium compounds. In contrast, the wet limestone FGD system can produce a marketable byproduct (i.e., gypsum).

Key design and operating parameters that can significantly affect dry scrubber performance are reagent-to-sulfur stoichiometric ratio, slurry droplet size, inlet water content, residence time, and scrubber outlet temperature. An excess amount of lime above the theoretical requirement is generally fed to the dry scrubber to compensate for mass transfer limitations and incomplete mixing. Droplet size affects scrubber performance. Smaller droplet size increases the surface area for reaction between lime and acid gases and increases the rate of water evaporation. A longer residence time results in higher chemical reactivities, and the reagent-$SO_2$ reaction occurs more readily when the lime is wet. The scrubber outlet temperature is controlled by the amount of water in the slurry. Typically, effective utilization of lime and effective $SO_2$ removal occur at temperatures close to adiabatic saturation, but the flue gas temperature must be kept high enough to ensure that the slurry and reaction products are adequately dried prior to the particulate collection process.

Because the dry scrubber absorber construction material is usually carbon steel, the capital costs are usually less expensive as compared with wet scrubbers. However, the necessary use of lime in the process increases its annual operational costs.

**Regenerative Process**

Regenerative FGD systems can be either wet or dry and result in a concentrated stream of $SO_2$, which can then be sold. These systems include sodium sulfite, magnesium oxide, sodium carbonate, and amine.

In regenerative processes, the sorbent is regenerated chemically or thermally and re-used. Elemental sulfur or sulfuric acid is recovered from the $SO_2$ removed. The revenue from these by-products can compensate partially for the higher capital cost required in such systems. In general, regenerative processes require no waste disposal, produce little wastewater, and have low sorbent make-up requirements. However, in most systems, a pre-scrubber is essential to control chlorides. Although these processes can achieve high $SO_2$ removal efficiencies (> 95 percent), they have in general high capital costs and power consumption.

**Evaluation of Technically Feasible Control Alternatives**

The technically feasible $SO_2$ controls for the bagasse boiler are listed in Table 5-8. As shown, there are four types of $SO_2$ abatement methods with various techniques of each method. Each available technique was listed with its associated efficiency estimate, identified as feasible or infeasible, and ranked based on control efficiency.

***Ranking of Technically Feasible Control Alternatives***

As shown in Table 5-8, wet FGD, spray dryer scrubbers, and the regenerative $SO_2$ scrubbing process are the highest ranked control technologies for biomass boilers, and can all achieve upwards of 95-percent control efficiency. However, past $SO_2$ BACT determinations for biomass-fired boilers have been based solely on fuel specifications (i.e., use of low sulfur fuel). Recently, biomass boilers have employed acid gas scrubbing systems for the purpose of controlling emissions of HCl, which is a HAP. These systems are used to reduce total HAP emissions to below major source threshold levels.

***Evaluation of Economic, Environmental, and Energy Impacts of Feasible Technologies***

**Economic**

Wet, dry, and regenerative FGD systems can all achieve the same level of $SO_2$ control efficiency. To evaluate the cost effectiveness of FGD applied to the bagasse boiler, cost estimates for a lime spray drying system were developed. Spray drying systems are generally less expensive than the wet limestone FGD process and are therefore more economical.

A cost quote from a major supplier was utilized for the economic analysis, and the analysis is presented in Appendix J. This quote is for a complete system, including the spray dryer absorber, pulse jet fabric filter, and ancillary equipment. To install a lime spray-drying system, increased $PM/PM_{10}$ control equipment would be required due the increased particulate loading caused by the spray drying systems. $SO_2$ removal was specified as 84 percent (presumably due to the low uncontrolled emissions). Based on the fuel heating value and sulfur content of the HEF fuels, the potential uncontrolled $SO_2$ emissions are 800 TPY.

Based on the cost analysis presented in Appendix J, the capital cost of lime spray drying with fabric filter is approximately \$8.0 million (see also Table 5-6). The annualized cost is approximately \$1.7 million. Based on uncontrolled emissions of $SO_2$ of 800 TPY, and assuming 84-percent removal, the total $SO_2$ removed is 674 TPY. The resulting cost effectiveness is approximately \$2,523 per ton of $SO_2$ removed.

However, the incremental cost of lime spray drying over the DSI/ESP technology is $1.2 million capital cost and $520,000 annual operating cost, for an incremental emission reduction of 72 TPY. This is over $7,000 per ton incremental cost compared to lime DSI/ESP. This cost is considered to be unreasonable and infeasible for the proposed project.

Wet and regenerative FGD control systems would have higher capital and annual operating costs with resulting higher cost effectiveness, and therefore were not evaluated with a detailed cost estimate.

**Environmental and Energy**

Wet or dry FGD systems would cause additional water usage and energy usage, and a liquid or solid waste would result that must be disposed.

***Selection of BACT and Rationale***

The proposed $SO_2$ BACT limit for the bagasse boiler for biomass firing is equivalent to 0.11 lb/MMBtu, 12-month rolling average. This limit is somewhat higher than other bagasse boilers (i.e., 0.06 lb/MMBtu), but this is due to the potentially higher sulfur content of sweet sorghum bagasse. HEF's proposed BACT for $SO_2$ is based on DSI, and the low sulfur content of bagasse, wood, and natural gas. The $SO_2$ emissions are a direct function of the fuel sulfur content. The uncontrolled $SO_2$ emissions from bagasse, wood, and natural gas are very low, which renders any add-on control equipment too costly. Further, there is inherent $SO_2$ and acid gas removal in the boiler/PM control system, estimated to be at least 75 percent without add-on control equipment, which should further reduce $SO_2$ emissions. The DSI system also provides up to 95 percent removal of HCl from the flue gas.

Each of the alternative $SO_2$ control systems would result in significant capital and operating costs for HEF. In summary, the proposed BACT for HEF is the use of DSI and very low sulfur fuels (i.e., bagasse, wood, and natural gas).

### *5.4.4 Sulfuric Acid Mist*

***Previous BACT Determinations***

Previous BACT determinations for SAM emissions from biomass-fired industrial and electric utility boilers are presented in Table 5-9. Only a few previous determinations exist. Combustion control through fuel specification is the only control method employed in these boiler BACT determinations for SAM. Emission limits range from 0.003 to 0.022 lb/MMBtu, based on no add-on controls. Although there is no limit proposed for SAM, the estimated bagasse boiler maximum emissions for SAM are consistent with these determinations.

***Identification of Potentially Applicable Control Technologies***

Emissions of SAM are related to $SO_2$ emissions. $SO_2$ and SAM emissions will be controlled by burning low sulfur bagasse fuel, low sulfur wood fuel, low sulfur content fuel oil, and propane. Bagasse fuel, wood fuel, low sulfur fuel oil, and propane are inherently low in sulfur, and therefore produce low SAM emissions.

Two potentially applicable control technologies for SAM emissions recently identified for electric utility units are wet ESPs and $NH_3$ injection downstream of an SCR unit. Wet ESPs can be used following a wet FGD system where the flue gas is saturated to collect SAM and liquid droplets remaining in the flue gas. SCR units have been identified as increasing SAM emissions by increasing the oxidation rate of $SO_2$ to $SO_3$. Injecting $NH_3$ downstream of the SCR acts to convert the $SO_3$ to ammonium sulfate.

Due to the already low SAM emissions from the bagasse boiler, no alternative technologies or additional add-on technologies are warranted for the bagasse boiler.

***Selection of BACT and Rationale***

The proposed BACT for SAM emissions is the use of low sulfur fuels. Since emissions of SAM are related to $SO_2$ emissions, BACT for $SO_2$ also represents BACT for SAM. The maximum potential SAM emissions are 4.9 percent of the $SO_2$ emissions due to firing any fuel. This is equivalent to a maximum of 9.8 TPY of SAM emissions.

### 5.4.5 Carbon Monoxide

***Previous BACT Determinations***

As part of the BACT analysis, a review was performed of previous CO BACT determinations for industrial and electric utility boilers listed in the RBLC on EPA's web page. A summary of BACT determinations for biomass-fired industrial and electric utility boilers from this review is presented in Table 5-10. From the review of previous BACT determinations, it is evident that the vast majority of CO BACT determinations for new biomass-fired industrial and electrical utility boilers have exclusively been based on GCPs. In a few cases, catalytic oxidation has been used. For spreader stoker bagasse-fired boilers, the BACT limits range from 0.10 lb/MMBtu (30-day rolling average) to 6.5 lb/MMBtu. For other biomass-fired spreader stoker boilers, the BACT limits range from 0.026 to 0.785 lb/MMBtu. For fluidized bed boilers (four determinations), the limits range from 0.070 to 0.12 lb/MMBtu.

Two oxidation catalyst systems for CO control are known to be in operation currently on biomass-fired boilers. These are the same units for which RSCR systems were employed for $NO_x$ control, previously described. These systems are employed on Burlington Electric and Biomass Energy, with CO emission limits of 1,500 ppmv and 0.10 lb/MMBtu, respectively. These are non-BACT limits, with the RSCR systems implemented on a voluntarily basis.

***Identification of Potentially Applicable Control Technologies***

The BACT analysis was performed based on those available and feasible control technologies that can provide the maximum degree of emission reduction for CO emissions. CO emissions, which result from incomplete combustion of fuel, are controlled by boiler design features and combustion air systems. The bagasse boiler will be designed and operated for high combustion efficiency, which will inherently minimize the production of CO. Emissions of CO are produced by the incomplete combustion of carbon. Carbon in the fuel which does not experience the required temperature or residence time at the required temperature will form CO or other organic compounds instead of being fully oxidized to $CO_2$. The important parameters in CO formation are combustion temperatures, gas residence time, and local stoichiometric ratio of fuel and air (i.e., mixing of fuel and air).

***Oxidation Catalyst***

CO emissions can be reduced by passing the flue gas over an oxidation catalyst at suitable temperature (900 to 1,000°F). Babcock Power offers such a system, which employs a canister system after the PM control device. The canister contains a CO catalyst. See Subsection 5.4.2 for a further description. Recently, a number of other vendors have been willing to provide quotes for oxidation catalyst systems. The catalysts are marketed as able to perform at relatively low temperatures, i.e., after the air heater where temperatures are approximately 500°F. At least five facilities have been permitted for oxidation catalysts. In practice, oxidation catalyst technology has only been applied to a few biomass-fired boilers, and several unknowns and disadvantages may exist, particularly as applied to a bagasse-fired boiler. These include the following:

1. Only two biomass-fired boilers are known to be operating with a catalytic CO control system. Therefore, there is a lack of experience with oxidation catalysts in biomass boilers, and no experience with one that fires bagasse.
2. As with SCR, catalysts can be easily poisoned, resulting in premature catalyst deactivation due to the alkali content of the ash.
3. The temperature profile of the flue gas does not match the temperature requirements of typical catalysts.
4. The high costs to install and operate the system (additional pressure drop, catalyst replacement and disposal, etc.) are without corresponding demonstrated need or benefit. Design and operation of the boilers to efficiently combust the fuel will minimize CO emissions. The additional costs to further lower emissions are not justified.

***Overfire Air Systems***

There are several novel OFA systems being offered on the market today that are applicable to biomass-fired stoker boilers. All attempt to improve air/fuel mixing and turbulence in the furnace, while maximizing gas residence time. Cold spots are reduced, and more complete carbon burnout is accomplished. Two of these systems, which have some experience on biomass-fired boilers, were described in Subsection 5.4.2 for $NO_x$ control. These same systems also can reduce CO emissions by accomplishing more complete combustion. The manufacturers indicate CO emissions reductions are achievable; however, these are for wood-fired boilers, which are much different than HEF's proposed bagasse-fired boiler. Without actual operating experience, it is not known what CO emission reduction would be achievable with such a system.

***Incinerators***

The use of thermal oxidation after the ESP, while also theoretically possible, is not feasible as BACT. Thermal oxidation systems include direct flame incinerators, thermal oxidizers, and afterburners. Afterburners are generally appropriate only to control gases coming from a process where combustion is incomplete, and are not appropriate for controlling boiler emissions. Incineration or thermal oxidation is the process of oxidizing combustible materials by raising the temperature of the material above its auto-ignition point in the presence of oxygen, and maintaining it at high temperature for sufficient time to complete combustion to $CO_2$ and water. Time, temperature, turbulence (for mixing), and the availability of oxygen all affect the rate and efficiency of the combustion process. The auto-ignition temperature of CO is 1,300°F. The use of oxidation catalyst (RCO) can reduce the temperature requirement down to 500°F for CO oxidation. However, with the recent improvement in low temperature catalysts, RCO is no longer a practical choice, except for retrofit situations.

While regenerative thermal oxidation (RTO) has been demonstrated on a cement kiln in Texas, RTO systems are not considered technically feasible for boilers with large gas flows, such as that associated with the proposed the bagasse boiler. The proposed boiler will have an estimated stack gas flow rate of approximately 200,000 actual cubic feet per minute (acfm). Thermal oxidation systems are typically designed for flow rates in the range of 500 to 50,000 acfm (EPA Air Pollution Control Fact Sheet – Thermal Oxidation). RTOs are considered technically and economically infeasible for the bagasse boiler.

***<u>Evaluation of Technically Feasible Control Alternatives</u>***

The technically feasible CO controls for the bagasse boiler are listed in Table 5-11. As shown, there are four types of CO abatement methods with various techniques of each method. Each available technique is listed with its associated efficiency estimate, identified as feasible or infeasible, and ranked based on control efficiency. Oxidation catalyst, OFA systems, and combustion controls are all technically feasible for reducing CO emissions from the combustion process. As discussed previously, nearly all recent permits issued for biomass boilers have required the use of GCPs to control CO because these controls are generally available, technically feasible, well proven, and provide the maximum degree of emission reduction.

Oxidation catalyst has also had limited application to biomass-fired boilers; however, none have operating experience with the unique fuels that the HEF bagasse boiler will burn (unique supply of bagasse). The most recent BACT determinations for boilers similar to HEF are the Highlands Ethanol and Southeast Renewable Fuels permits issued in Florida. The Highlands permit required good combustion controls with a fluidized bed boiler, and the Southeast Renewable Fuels permit required oxidation catalyst "if needed" to meet the CO permit limit of 0.10 lb/MMBtu, 30-day rolling average. FBEnergy in Florida, a non-BACT permit, also specifies the use of oxidation catalyst for a wood biomass-fired boiler.

***Ranking of Technically Feasible Control Alternatives***

The technically feasible CO control methods are ranked in Table 5-11 based on emission reduction effectiveness. CO oxidation is the most effective method for controlling CO emissions and will achieve the maximum degree of CO emission reduction, with an estimated CO removal efficiency of 60 to 80 percent. The next most effective methods for CO control are enhanced OFA systems, with a control efficiency of 70 percent. GCPs rank next in effectiveness.

Previous BACT emission limits established for biomass-fired units have required combustion control as the method used to control CO emissions. Oxidation catalysts have been determined to be BACT for CO in only two instances: NRG Energy (Connecticut) and Loblolly Green Power (SC). Other technologies such as thermal oxidation are not demonstrated or feasible for biomass-fired boilers.

***Evaluation of Economic, Environmental, and Energy Impacts of Feasible Technologies***

***Economic***

The cost analysis for "tail-end" oxidation catalyst is presented in Table 5-5 and 5-6. As shown, the estimated capital cost of oxidation catalyst is $1.4 million. The total annual costs are estimated at over $360,000 per year. For the HEF spreader stoker boiler, oxidation catalyst would reduce CO and VOC emissions by an estimated 60 percent, from 584.3 TPY to 239.6 TPY, for a 345 TPY reduction. The cost effectiveness of oxidation catalyst for CO and VOC control is $1,044 per ton reduced. The cost of oxidation catalyst is therefore comparatively low.

One enhanced OFA system was further evaluated for economic impacts. The cost analysis is presented in Table 5-6. Costs are based on a quote from a major vendor and standard cost factors. The estimated capital cost is $3.1 million, and the annual cost is $500,000 per year. A 25-percent reduction in CO is quoted, resulting in a reduction of 146 TPY in CO emissions. The resulting cost effectiveness is $3,400 per ton of CO removed. This high capital and operating cost coupled with lack of operating experience on a bagasse boiler rules out this technology.

***Environmental***

No additional significant environmental impacts from oxidation catalyst or OFA technology are anticipated.

***Energy***

Energy penalties occur with oxidation catalyst and OFA. Oxidation catalyst will require inputs of energy. OFA requires energy due to additional fans.

***Selection of BACT and Rationale***

The identification, technical evaluation, and ranking of the available control technologies indicate that combustion controls and oxidation catalyst provide the maximum degree of CO emission reduction. The evaluation of the energy, environmental, and economic impacts demonstrate that oxidation catalyst is relatively cost effective. However, catalyst vendors are not willing to guarantee the catalyst for more than one year of operation. This is also a testament to the total lack of operating experience with these systems on biomass, and in particular sugarcane and sweet sorghum bagasse. Therefore, additional costs could result based on unforeseen problems encountered with the system.

The primary reason for reducing CO emissions is to minimize emissions of organic HAP. However, as demonstrated for the proposed HEF boiler, based on test data from similar bagasse boilers, the facility will be a minor source of HAPs (i.e., less than 25 TPY all HAPs combined), even with the proposed CO limit of 0.30 lb/MMBtu. In order to ensure that the facility maintains a minor HAP source, HEF will make provisions to be able to install a CO catalyst after the ESP, if test data after operations begin demonstrates the catalyst is needed to maintain the minor source status.

CO emissions at 0.30 lb/MMBtu for the proposed boiler result in no significant impact on CO ambient air quality, as the modeling analysis is Section 6.0 demonstrates.

For all these reasons, oxidation catalyst is rejected as BACT for CO emissions for the bagasse boiler.

An enhanced OFA system, although potentially capable of lowering CO by up to 25 percent, is also costly and unproven on a bagasse-fired boiler. The next most effective CO control technology, modern OFA combustion design and controls, is selected as BACT for the bagasse boiler. OFA is feasible and reasonable based on the economic, environmental, and energy impacts. A CO emission rate of 0.30 lb/MMBtu), 30-day rolling average, is proposed as BACT for the hybrid suspension/grate type bagasse boiler. This limit is equal to the most recent BACT determination for an operating hybrid suspension/grate bagasse-fired boiler, i.e., Boiler No. 8 at U.S. Sugar Corporation.

The proposed CO BACT limit of 0.30 lb/MMBtu is equivalent to approximately 400 ppmvd at 3 percent $O_2$, 30-day rolling average. It is noted that this limit is well below the Boiler MACT limit recently promulgated for new source hybrid suspension/grate boilers of 1,500 ppmvd at 3 percent $O_2$; however, this limit includes malfunction events.

### *5.4.6 Volatile Organic Compounds*

***Previous BACT Determinations***

A review was performed of previous VOC BACT determinations for industrial and electric utility boilers listed in the RBLC on EPA's web page, and a summary for biomass-fired industrial and electric utility boilers is presented in Table 5-12. The VOC BACT emission limits for biomass-fired industrial and electric utility boilers range from 0.005 to 0.50 lb/MMBtu. This rather large range of emissions is due to differences in boiler design and operation, as well as fuel differences. From the review of previous determinations, it is evident that VOC BACT determinations for biomass-fired industrial and electric utility boilers have been GCPs and boiler design. One facility, Biomass Energy, employs an oxidation catalyst for CO emission reduction, which also reduced VOC emissions.

***Identification of Potentially Applicable Control Technologies***

***Refrigerated Condensers***

The most common types of condensers used are surface and contact condensers. In surface condensers, the coolant does not contact the gas stream. Most surface condensers in refrigerated systems are shell and tube type. Shell and tube condensers circulate the coolant through tubes. The VOCs condense on the outside surface of the tube. Plate and frame type heat exchangers are also used as condensers in refrigerated systems. In these condensers, the coolant and the vapor flow separately over thin plates. In either design, the condensed VOC vapors drain away to a collection tank for storage, reuse, or disposal.

Contact condensers cool the vapor stream by spraying either a liquid at ambient temperature or a chilled liquid directly into the gas stream.

Refrigerated condensers are used as air pollution control devices for treating emissions with high VOC concentrations (>5,000 ppmv), in applications involving gasoline bulk terminals, storage, etc. Refrigerated condensers are not technically feasible for reduction of VOC from industrial boilers, and as such are not technically feasible for the bagasse boiler.

***Carbon Adsorbers***

Adsorption is employed to remove VOC compounds from low to medium concentration gas streams. Adsorption is a phenomenon where gas molecules passing through a bed of solid particles are selectively held there by attractive forces, which are weaker and less specific than those of chemical bonds. During adsorption, a gas molecule migrates from the gas stream to the surface of the solid where it is held by physical attraction, releasing energy, the heat of adsorption, which typically equals or exceeds the heat of condensation. Adsorption capacity of the solid for the gas tends to increase with the gas phase concentration, molecular weight, diffusivity, polarity, and boiling point. Gases form actual chemical bonds with the adsorbent surface groups.

There are five types of adsorption techniques (see Table 5-13). Of the five techniques, fixed bed units are typically utilized for controlling continuous VOC-containing streams from flow rates ranging from several hundred to several thousand acfm. Based on the gas flow rate of the bagasse boiler, carbon adsorption is not technically feasible for this project.

***Oxidation, OFA Systems, and Good Combustion Practices***

These techniques were described in Subsection 5.4.5 for CO emissions. CO and VOC emissions are closely related, and these techniques apply equally to VOC emissions.

***Flare***

Flaring is a VOC control process in which the VOCs are piped to a remote, usually elevated, location and burned in an open flame in the open air using a specially designed burner tip and auxiliary fuel. Flares are not technically feasible for the bagasse boiler due to the large gas volume and low Btu value of the gas stream.

***Incinerators***

The two basic types of incinerators are thermal and catalytic. Thermal systems may be direct flame incinerators with no energy recovery, flame incinerators with a recuperative heat exchanger, or regenerative systems, which operate in a cyclic mode to achieve high-energy recovery. Catalytic systems include fixed bed (packed bed or monolith) systems and fluid-bed systems, both of which provide for energy recovery. Catalytic systems are not an option for biomass combustion due to catalyst poisoning.

Although thermal incinerators are theoretically feasible for the bagasse boiler, the high flue gas volume and low concentration of VOCs would require that the flow be split into two gas streams and fed into two separate incinerators. In addition, it is estimated that the total incinerator natural gas usage would be approximately 24,000 scf/hr, equal to 210 million standard cubic feet per year (MMscf/yr). The combustion of natural gas would result in increased $NO_x$ emissions. For these reasons, incineration is considered not technically feasible for the bagasse boiler.

***Evaluation of Technically Feasible Control Technologies***

The technically feasible VOC controls for the bagasse boiler are listed in Table 5-13. As shown, there are four types of VOC abatement methods with various techniques of each method. Each available technique was listed with its associated efficiency estimate, identified as feasible or infeasible, and ranked based on control efficiency. As presented in the table, the only technically feasible VOC control technologies for biomass-fired boilers are the same techniques described in above for CO emissions.

***Selection of BACT and Rationale***

The proposed VOC emission limit for the hybrid suspension/grate bagasse boiler is 0.017 lb/MMBtu, achieved through good combustion practices. This proposed emission limit is within the range of previous determinations, and is lower than most bagasse-fired boilers. The bagasse boiler will minimize VOC through proper furnace design and GCPs, including the following:

- Advanced OFA system design
- Control of combustion air and combustion temperature

- Controlled distribution of fuel on the combustion gate
- Better controls over the furnace loads and transient conditions

Use of an oxidation catalyst could potentially lower VOC emissions further. However, the shortcomings of using this technology have been previously described. Like for CO, the primary driver for a oxidation catalyst is to insure that the facility remains a minor source for HAPs emissions. As described previously, HEF will make provisions for installation of an oxidation catalyst, in the event that it is needed to render the facility a minor source of HAPs.

## 5.5 Volatile Organic Liquid Storage Tanks

The HEF Facility will have four VOL storage tanks subject to NSPS Subpart Kb. These tanks will store fuel ethanol, denaturant/gasoline, 200-proof ethanol, and off-spec ethanol, and will have capacities ranging from 100,000 to 1,000,000 gallons. These tanks will either be fitted with internal floating roofs meeting NSPS specifications, or will have a pressure relief device/vent condenser to control VOC emissions to an equivalent level. VOC emissions from these tanks combined are estimated at 3.9 TPY.

Internal floating roofs that meet NSPS requirements represent the state of the art for control of VOC emissions from floating roof tanks, and have been previously determined to represent BACT for VOL storage tanks. Other options include external floating roofs and venting to an add-on control device, but these options represent equivalent control.

The facility will also have one other VOL storage tank for corrosion inhibitor (2,300 gallon capacity). This tank will be a vertical fixed roof tank. Emissions from this tank are estimated at only 0.006 TPY, estimated from the TANKS program.

Use of a fixed roof tank for this small, low-emitting tank represents BACT because it is not cost effective to fit the tank with internal or external floating roofs, or to vent these tanks to a flare or vapor recovery unit.

# 6.0 AIR QUALITY IMPACT ANALYSIS

## 6.1 Significant Impact Analysis Approach

### *6.1.1 General*

The general modeling approach for the significant impact analysis for HEF followed EPA and FDEP modeling guidelines for determining compliance with AAQS and PSD increments. For all criteria pollutants that will be emitted in excess of the PSD significant emission rate due to a proposed project, a significant impact analysis is performed to determine whether the emission and/or stack configuration changes due to the project alone will result in predicted impacts that are in excess of the EPA significant impact levels. For the HEF project, emission increases above the PSD significant emission rates occur for the following criteria pollutants: $SO_2$, $NO_x$, PM, $PM_{10}$, $PM_{2.5}$, CO, and VOC.

Because AAQS and PSD increments do not exist for total PM or VOC, air impacts for these pollutants are not required. Therefore, the pollutants $SO_2$, $NO_x$, $PM_{10}$, $PM_{2.5}$, and CO require a significant impact analysis.

### *6.1.2 Site Vicinity*

If the maximum project-only impacts are above the significant impact levels in the vicinity of the project, then two additional, more detailed air modeling analyses are required. Current FDEP policies stipulate that the highest annual average and highest short-term (i.e., 24-hour or less) concentrations are to be compared to the applicable significant impact levels (see Table 3-1). The first analysis demonstrates compliance with federal and Florida AAQS, and the second analysis demonstrates compliance with allowable PSD Class II increments.

For the 1-hour $SO_2$ significant impact level, EPA recommends an interim level of 3 parts per billion (ppb) or 7.9 µg/m$^3$ in the memorandum, *General Guidance for Implementing the 1-hour SO2 National Ambient Air Quality Standard in Prevention of Significant Deterioration Permits, Including an Interim 1-hour $SO_2$ Significant Impact Level*, issued on August 23, 2010. The project impacts are considered to be less than significant if the highest 5-year average concentration of maximum modeled daily 1-hour concentrations, based on using 5-years of meteorological data, is predicted to be less than the interim significant impact level. This level is intended to be used as a screening tool for completing the required air quality analyses for the 1-hour $SO_2$ National Ambient Air Quality Standards (NAAQS) under the federal PSD program under 40 CFR 52.21. This screening tool is available to states with EPA-approved implementation plans containing PSD programs, to use at their discretion.

Similar to the 1-hour $SO_2$ significant impact level, EPA recommends an interim 1-hour $NO_2$ significant impact level of 4 ppb or 7.6 µg/m$^3$ in the memorandum, *General Guidance for Implementing the 1-hour*

*$NO_2$ National Ambient Air Quality Standard in Prevention of Significant Deterioration Permits, Including an Interim 1-hour $NO_2$ Significant Impact Level*, issued on June 28, 2010. The project impacts are considered to be less than significant if the highest 5-year average concentration of maximum modeled daily 1-hour concentrations, based on using 5-years of meteorological data, is predicted to be less than the interim significant impact level. This level is also intended to be used as a screening tool for completing the required air quality analyses for the 1-hour $NO_2$ NAAQS under the federal PSD program at 40 CFR 52.21, and is available to states with EPA-approved implementation plans containing PSD programs, to use at their discretion.

For $PM_{2.5}$, the 24-hour and annual significant impact levels of 1.2 and 0.3 µg/m$^3$, respectively, were finalized by EPA on October 20, 2010 (FR Vol. 75, No. 202, pages 64864-64907) and were effective as of December 20, 2010. These levels are intended to be used as screening tools for completing the required air quality analyses.

### *6.1.3 Far Field*

Generally, if a major new facility or major modification is located within 200 km of a PSD Class I area, then a significant impact analysis is also performed to evaluate the impacts of the project alone at the PSD Class I area. The ENP, located about 147 km from the project site, is the only PSD Class I area that is located within 200 km of the HEF site. The maximum predicted impacts are compared to EPA's recommended significant impact levels for PSD Class I areas (Table 3-1). These recommended levels are the currently accepted criteria to determine whether a proposed project will incur a significant impact on PSD Class I areas.

Similar to the $PM_{2.5}$ PSD Class II increments, EPA finalized the 24-hour and annual PSD Class I significant impact levels for $PM_{2.5}$ of 0.07 and 0.06 µg/m$^3$, respectively, on October 20, 2010, which became effective as of December 20, 2010. These levels are intended to be used as screening tools for completing the required air quality analyses.

If the maximum project-only impacts at ENP are above the recommended EPA PSD Class I significant impact levels, then a cumulative source analysis is performed to demonstrate compliance with allowable PSD Class I increments.

## 6.2 Pre-Construction Monitoring Analysis Approach

The proposed project's maximum impacts are compared to the *de minimis* monitoring levels to determine whether the project is subject to pre-construction monitoring requirements. For all applicable pollutants that have emission increases greater than the PSD significant emission rates, an impact analysis is performed to determine whether the project alone will result in predicted impacts that will exceed the EPA *de minimis* monitoring levels at any off-plant property locations in the vicinity of the plant. Current FDEP policies stipulate that the predicted highest annual average and highest short-term concentrations are to be compared to the applicable *de minimis* monitoring levels (Table 3-2). EPA recently finalized the *de minimis* monitoring level for $PM_{2.5}$ of 4.0 µg/m$^3$, 24-hour average, on October 20, 2010, which became effective as of December 20, 2010.

A proposed major stationary facility or major modification may be exempt from pre-construction ambient monitoring requirements with respect to a particular pollutant if the emissions increase of that pollutant due to the project would result in air quality impacts less than the *de minimis* monitoring levels. As presented in Section 4.0, the project's maximum predicted pollutant impacts are less than the *de minimis* monitoring concentration levels for all pollutants except for $PM_{10}$, $PM_{2.5}$, $SO_2$ and VOC (ozone). As such, preconstruction ambient monitoring analysis is required for $PM_{10}$, $PM_{2.5}$, $SO_2$, and ozone. The required analysis is presented in Section 4.0.

## 6.3 Cumulative Source Impact Analyses Approach

### *6.3.1 AAQS and PSD Class II Analysis*

If the project-only impacts are greater than the significant impact levels, the air modeling analyses must consider other nearby sources and background concentrations, and determine the cumulative impact of these sources for comparison to AAQS and PSD increments.

As described in Section 6.10, HEF's project-only maximum impacts for the following pollutants and averaging times are predicted to be greater than the significant impact levels:

- $SO_2$: 1-hour and 24-hour averages
- $PM_{10}$: 24-hour and annual averages
- $PM_{2.5}$: 24-hour and annual averages
- $NO_2$: 1-hour average

Therefore, additional air modeling analyses must be performed for these pollutants and averaging times that consider other nearby sources and background concentrations, in order to determine the cumulative impact of these sources for comparison to ambient air standards. In general, when 5 years of meteorological data are used in the analysis, the highest annual and the HSH short-term concentrations are compared to the applicable AAQS and allowable PSD increments. The HSH concentration is calculated each year for a receptor field by:

1. Eliminating the highest concentration predicted at each receptor
2. Identifying the second-highest concentration at each receptor
3. Selecting the highest concentration among these second-highest concentrations

The approach is consistent with AAQS and allowable PSD increments, which permit a short-term average concentration to be exceeded once per year at each receptor.

For determining compliance with the 24-hour AAQS for $PM_{10}$, the highest of the sixth-highest concentrations predicted at each receptor over 5 years of meteorological data (i.e., H6H), instead of the HSH concentration predicted for each year, is used to compare to the applicable 24-hour AAQS. For determining compliance with the 24-hour AAQS for $PM_{2.5}$, the $98^{th}$ percentile of the predicted maximum 24-hour concentrations at each receptor, averaged over 5 years of meteorological data, is selected to compare to the AAQS. For determining compliance with the annual AAQS for $PM_{2.5}$, the predicted maximum annual concentrations at each receptor, averaged over 5 years of meteorological data, is selected to compare to the AAQS.

For determining compliance with the 1-hour AAQS for $NO_2$, the $98^{th}$ percentile of the predicted daily 1-hour maximum concentrations at each receptor, averaged over 3 years of meteorological data, is selected to compare to the applicable AAQS. For determining compliance with the 1-hour AAQS for $SO_2$, the $99^{th}$ percentile of the predicted daily 1-hour maximum concentrations at each receptor, averaged over 3 years of meteorological data, is selected to compare to the applicable AAQS.

The AAQS analysis is a cumulative source analysis that evaluates whether the air quality impact concentrations from all sources will comply with the AAQS. These concentrations include the modeled impacts from sources at the HEF facility and from other nearby facility sources, added to a background concentration. The background concentration accounts for sources not included in the modeling analysis.

The PSD Class II analysis is a cumulative source analysis that evaluates whether the air quality impact concentrations for increment-affecting sources will comply with the allowable PSD Class II increments. These concentrations include the modeled impacts from PSD increment-affecting sources at HEF, plus nearby PSD increment-affecting sources at other facilities.

### *6.3.2 PSD Class I Analysis*

For each pollutant for which the maximum predicted impact exceeds the proposed Class I significant impact level, a cumulative source PSD Class I analysis is required.

In addition to PSD Class I increment analysis, AQRV analyses of visibility impairment and acid deposition are generally requested to be performed by the Federal Land Manager (FLM) of the Class I areas. However, based on the project's emissions and distance from the Class I areas, the FLM may determine that modeling for the project would not show any significant additional impacts to the AQRV (see Section 7.4). When AQRV impacts are expected to be low and not required by the FLM, FDEP and EPA Region IV recommend using a conservative screening modeling procedure with the American Meteorological Society and EPA Regulatory Model (AERMOD) to estimate the project's impacts for comparison to the Class I SIL and to address compliance with the PSD Class I increments.

Upon review of the HEF project's emissions and distance that the project is from the ENP PSD Class I area, the project's impacts are anticipated to not show any significant additional impacts to the AQRV at the PSD Class I area. As such, analyses of the project's impacts on AQRV of visibility impairment and acid deposition at the PSD Class I area are not included in this report. Therefore, AERMOD was used to estimate the project's impacts for comparison to the Class I SILs, based on conservative screening procedures recommended by FDEP. More details are provided in Section 7.0 to support the rationale for assessing the project's impacts using this approach.

## 6.4 Model Selection

The selection of one or more air quality models to estimate maximum air quality impacts must be based on the model's ability to simulate impacts in all key areas surrounding a project site. For predicting concentrations at receptors that are located within 50 km of a project site, FDEP recommends using the AERMOD dispersion model. The AERMOD model was selected and used for predicting concentrations in the vicinity of the HEF site. In addition, AERMOD was used for predicting concentrations at 50 km in the direction of ENP in order to represent the project's impacts at the PSD Class I area following FDEP's screening procedures. Concentrations were also predicted at 100 km in the direction of ENP to ensure that the project's impacts would be less than the PSD Class I significant impact levels.

AERMOD calculates hourly concentrations based on hourly meteorological data and is applicable for most applications, since it is recognized as containing the latest scientific algorithms for simulating plume behavior in all types of terrain. AERMOD Version 11103 is the most recent available version on EPA's Internet web site: Support Center for Regulatory Air Models (SCRAM) within the Technology Transfer Network (TTN). A listing of AERMOD features is presented in Table 6-1.

For modeling analyses that will undergo regulatory review, such as PSD permit applications, the following modeling features are recommended by EPA and are incorporated as the regulatory default options in AERMOD:

- Use of elevated terrain algorithms
- Stack-tip downwash
- Missing data processing routines
- 4-hour half-life for exponential decay of $SO_2$ for urban sources
- Calm wind processing routines

For this project, the EPA regulatory default options were used to address maximum impacts.

## 6.5 Meteorological Data

### *6.5.1 Site Vicinity*

Meteorological data used with the AERMOD model to determine air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations from the Fort Myers Southwest Florida Regional (RSW) Airport in Fort Myers and upper air sounding data collected at Tampa International Airport (TIA) in Tampa. The period of record is 2001 through 2005. The Fort Myers RSW airport is located approximately 85 km (53 miles) south-southwest of the site and is the closest primary weather station to the study area considered to have meteorological data representative of the project site. Because the Fort Myers meteorological station is only 85 km from the HEF site and the terrain between the two sites is mostly flat, the wind direction and wind speed frequencies that are experienced at Fort Myers are considered to be very similar to that experienced at the HEF site. As such, the Fort Myers wind direction and wind speed frequencies are considered to be representative of the HEF site.

AERMOD incorporates land use parameters for determining boundary layer parameters that are used for dispersion. AERSURFACE reads land use files developed by the U.S. Geological Survey (USGS) and provides average land use values for albedo, Bowen ratio, and surface roughness within a specified radius. Current air modeling guidance suggests that the land use parameters should be representative of the data measurement site (i.e., Fort Myers RSW). In January 2008, EPA released new recommendations for determining the surface land use characteristics in its AERMOD Implementation Guide. The Guide recommends the following procedures:

- Surface roughness length should be based on an inverse-distance weighted geometric mean for the default upwind distance of 1 km relative to the measurement site.
- The Bowen ratio should be based on a simple, unweighted geometric mean over a default 10-km by 10-km domain. There should be no direction or distance dependency for the data.
- The albedo should be based on a simple unweighted arithmetic mean for the same domain used for the Bowen ratio.

AERSURFACE Version 08009 (EPA, January 9, 2008) was used to calculate these surface characteristics. Land cover data were obtained from the USGS National Land Cover Data 1992 archives

(NLCD92) in the form of a GeoTIFF file covering the entire state of Florida. The USGS data were downloaded from the following website:

http://edcftp.cr.usgs.gov/pub/data/landcover/states/

Land use data values that exist within a 1-km radius of Fort Myers RSW and the HEF site were extracted from 7.5-degree land use files from the USGS using the AERSURFACE program. AERSURFACE currently extracts land use data in 12 wind direction sectors covering 360 degrees. The average land use values within 1 km of each site area are as follows:

Average land use at Fort Myers RSW:

- Albedo – 0.15
- Bowen ratio – 0.4
- Surface roughness – 0.109 meters (m)

Average land use at the HEF site:

- Albedo – 0.16
- Bowen ratio – 0.47
- Surface roughness – 0.547 m

While the average albedo and Bowen ratio for the two sites are considered similar, the surface roughness values are slightly different. Because the area of the approximate 75-acre HEF site will be cleared and the trees will be removed, the surface roughness, shown based on existing land use, will be lower when the project is constructed and operated. As a result, the difference in land use values between the two sites, particularly for surface roughness, will be less and not expected to be a significant factor in evaluating impacts. As such, the Fort Myers RSW meteorological data were selected for the proposed HEF project since they are considered the most representative data of the project site conditions and are readily available for modeling of the HEF sources.

## 6.6 Emission Inventory

### *6.6.1 Significant Impact Analysis*

A significant impact analysis was performed for $SO_2$, $NO_x$, $PM_{10}$, $PM_{2.5}$, and CO. A summary of the modeled emission rates for the proposed project is presented in Table 6-2. Emissions for the bagasse boiler are based on the maximum emissions while firing bagasse, as presented in Tables 2-12 and 2-13.

Physical stack and stack operating parameters for the proposed project that were used in the air modeling analysis are presented in Table 6-3. The proposed bagasse boiler will have a stack height of 150 ft and an inner stack diameter of 14 ft.

To address $PM_{10}$ and $PM_{2.5}$ impacts from the proposed project, $PM_{10}$ and $PM_{2.5}$ sources were modeled explicitly using the maximum $PM_{10}$ and $PM_{2.5}$ emission rates (see Table 6-3). These sources include the bagasse boiler, three cooling towers, truck load out flare, the material handling operations for biomass and flyash for the boiler, and truck traffic. The basis for the fugitive emissions estimates is presented in Table 2-16 and Appendix C.

### 6.6.2 *AAQS and PSD Class II Analyses*

The maximum pollutant impacts for the proposed project are predicted to be less than the significant impact levels for all pollutants and averaging periods except for the following:

- $SO_2$: 1-hour and 24-hour averages
- $PM_{10}$: 24-hour and annual averages
- $PM_{2.5}$: 24-hour and annual averages
- $NO_2$: 1-hour average

As a result, cumulative source impact analyses were conducted to determine compliance with AAQS and PSD Class II increments for these pollutants.

A significant impact area (SIA) and the radius of the SIA were determined for each pollutant and averaging time combination for which the proposed project's impact is predicted to be significant. The radius of impact was used as the basis for determining the inventory of background sources to be included in the air impact analyses.

The proposed project's SIAs were determined for the following pollutants and averaging times:

- $SO_2$: 4.8 and 0.9 km for the 1-hour and 24-hour averages, respectively
- $PM_{10}$: 1.4 and 0.4 km for the 24-hour and annual averages, respectively
- $PM_{2.5}$: 2.9 and 0.4 km for the 24-hour and annual averages, respectively
- $NO_2$: 12 km for the 1-hour average

Data on background $SO_2$, $PM_{10}$, $PM_{2.5}$, and $NO_2$ sources were obtained from FDEP. Facilities located within the SIA were modeled explicitly (i.e., the modeling area). Facilities within the SIA plus 50 km were considered to be in the screening area.

For averaging times greater than 1-hour, all facilities in the screening area were evaluated using the North Carolina screening technique (also known as the "20D approach"). Based on this technique, facilities whose annual emissions (i.e., TPY) are less than the threshold quantity, Q, are eliminated from the modeling analysis. Q is equal to 20 × (D – SIA), where D is the distance in km from the facility to the Site.

In addition, the source inventories were evaluated to identify major emitting facilities located beyond the screening area but within 100 km of the HEF site. Facilities in this area that have the potential to emit more than 1,000 TPY were included in the modeling inventory.

For the 1-hour $SO_2$ and $NO_2$ analyses, recommendations from EPA's memorandum, *Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour $NO_2$ National Ambient Air Quality Standard*, issued on March 1, 2011, were considered. This memorandum, also applicable to the 1-hour $SO_2$ NAAQS, presents EPA's strong suggestion that "the emphasis in determining which nearby sources to include in the modeling analysis should focus on the area within about 10 km of a project location in most cases. The routine inclusion of all sources within 50 km of the project location, the nominal distance for which AERMOD is applicable, is likely to produce an overly conservative result in most cases."

Based on these recommendations, facilities within 10 km of the HEF site were modeled (for $NO_2$, facilities within the SIA of 12 km). Major emitting facilities located beyond the modeling area but within the screening area were identified and modeled if their emissions were greater than 250 lb/hr (i.e., approximately 1,000 TPY).

Permit-allowable emission rates were used for the AAQS analysis as available. Actual emission rates are recommended for PSD Class II increment analysis. However, data on actual emission rates are more difficult to gather for $PM_{10}$, $PM_{2.5}$, $SO_2$, and $NO_2$. As a conservative approach, potential or permit-allowable emission rates were used for most of the sources in the $PM_{10}$ ($PM_{2.5}$ emissions were based on $PM_{10}$ emissions), $SO_2$, and $NO_2$ PSD Class II increment analyses.

Listings of $SO_2$ sources that were used in the AAQS and PSD Class II analyses and their locations relative to HEF are provided in Table 6-4 for the 24-hour averaging time and Table 6-5 for the 1-hour averaging time. Similarly, listings of $PM_{10}$/ $PM_{2.5}$ and $NO_2$ sources that were used in the AAQS and PSD Class II analyses and their locations relative to HEF are provided in Tables 6-6 and 6-7, respectively. Detailed $SO_2$, $PM_{10}/PM_{2.5}$, and $NO_2$ source data that were used for the AAQS and PSD Class II increment analyses are presented in Appendix K.

### 6.6.3 *PSD Class I Analysis*

The maximum impacts due to the HEF project are predicted to be less than the recommended PSD Class I significant impact levels for most pollutants and averaging periods at 50 km distance, but slightly greater than significant impact levels for certain pollutants at that distance (refer to Section 6.10). At 100 km, the maximum impacts due to the HEF project are predicted to be less than the significant impact levels for all pollutants and averaging periods. As a result, cumulative source impact analyses were not performed at ENP since the project's impacts are expected to be well below the PSD Class I significant impact levels at ENP.

## 6.7 Building Downwash Effects

Aerodynamic forces in the vicinity of structures and obstacles, such as buildings, disturb atmospheric flow fields. This flow disturbance near buildings and other structures can enhance the dispersion of emissions from stacks affected by the disturbed flow. The disturbance can also reduce the effective height of emissions from stacks located near buildings and obstacles. The height of these disturbances can be compared to the release points of modeled sources. For sources with release points above these disturbances, the effect on dispersion is not significant.

The AERMOD model specifically incorporates the effects of atmospheric downwash by utilizing downwash algorithms based on stack and building locations and heights which are input to the model. Significant proposed building structures at HEF were identified by the site plot plan (see Figure 2-3). Building dimensions for the structures were entered into the EPA's Building Profile Input Program (BPIPPRM, Version 04274) for the purpose of developing wind direction-specific building dimensions for input to AERMOD. The dimensions of the proposed structures are shown in Table 6-8.

## 6.8 Receptor Locations

### 6.8.1 *Site Vicinity*

Receptor locations used in the modeling analysis were based on Universal Transverse Mercator (UTM) coordinates from Zone 17, North American Datum 1983 (NAD83). The air modeling origin was assumed to be located at the approximate center of the HEF site, UTM east and north coordinates of 466,400 and 3,009,000 meters, respectively.

In general, a Cartesian receptor grid was used extending from the plant property boundary out to 7 km. Receptors were located at the following intervals and distances from the origin:

- Every 50 meters along the HEF property boundary
- Every 100 meters from the plant property to 2,000 meters

- Every 250 meters from 2,000 to 7,000 meters

For addressing the 1-hour $NO_2$ NAAQS, the modeling grid was extended out to 15 km with additional receptors located every 500 meters from 7,000 to 10,000 meters and every 1000 meters from 10,000 to 15,000 meters.

The heights above msl for all receptors were extracted using seamless National Elevation Data (NED) from the USGS website.

### *6.8.2 Everglades National Park*

The project's impacts to address potential impacts at the ENP were predicted at 68 receptors located at 50 and 100 km in the direction of ENP.

## 6.9 Background Concentrations

Background concentrations are used to determine total ambient air quality impacts to demonstrate compliance with the AAQS. "Background concentrations" are defined as concentrations due to sources other than those specifically included in the modeling analysis. For all pollutants, background includes other point sources not included in the modeling analysis (i.e., distant sources or small sources), fugitive emission sources, and natural background sources. In general, monitoring data collected near the area in which the air quality impact is performed is used for this purpose.

Summaries of ambient $SO_2$, $PM_{10}$, $PM_{2.5}$, and $NO_2$ concentrations measured in the HEF Site area are presented in Section 4.0. Based on data collected from 2008-2010, the following values were selected to represent background:

- $SO_2$ concentrations
  - second-highest 24-hour average of 26.2 $\mu g/m^3$
  - 3-year average of the 99$^{th}$ percentile of the maximum daily 1-hour average of 18.3 $\mu g/m^3$
- $PM_{10}$ concentrations
  - second-highest 24-hour average of 60 $\mu g/m^3$
  - highest annual average of 20 $\mu g/m^3$
- $PM_{2.5}$ concentrations
  - 3-year average of the 98$^{th}$ percentile of the maximum 24-hour average of 14.7 $\mu g/m^3$
  - 3-year average of the highest annual average of 6.5 $\mu g/m^3$

- $NO_2$ concentration:
  - 3-year average of the 98th percentile of the maximum daily 1-hour average of 45.1 µg/m$^3$

## 6.10 Model Results

### 6.10.1 PSD Class II Significant Impact Analysis

The maximum pollutant concentrations predicted for the proposed HEF project, including $PM_{10}$ and $PM_{2.5}$ concentrations due to the boiler, cooling towers, flares, material handling operations, and vehicular traffic, are compared to the PSD Class II significant impact levels in Table 6-9.

The modeling results indicate that maximum concentrations due to the proposed project are predicted to be less than the significant impact levels for all pollutants, except for the following:

- $SO_2$: 1-hour and 24-hour averages
- $PM_{10}$: 24-hour and annual averages
- $PM_{2.5}$: 24-hour and annual averages
- $NO_2$: 1-hour average

Therefore, a cumulative AAQS and PSD Class increment analyses were conducted for these pollutants.

### 6.10.2 PSD Class I Significant Impact Analysis

The maximum $SO_2$, $NO_2$, $PM_{10}$, and $PM_{2.5}$ concentrations predicted for the proposed project to address potential impacts at the ENP are presented in Table 6-10. The maximum impacts are predicted to be less than the recommended PSD Class I significant impact levels for most pollutants and averaging periods at 50 km, but slightly greater than significant impact levels for the 24-hr $SO_2$ at that distance. At 100 km, the maximum impacts due to the HEF project are predicted to be less than the significant impact levels for all pollutants and averaging periods. As a result, cumulative source impact analyses were not performed at ENP since the project's impacts are expected to be well below the PSD Class I significant impact levels at ENP.

### 6.10.3 AAQS Analyses

A summary of the results of the modeling analyses to demonstrate compliance with the AAQS is presented in Table 6-11. The maximum predicted concentrations are as follows:

- $SO_2$ Concentrations
  - HSH 24-hour concentration is 54.1 µg/m$^3$, which is well below the AAQS of 260 µg/m$^3$
  - 5-year average of the 99$^{th}$ percentile of the maximum daily 1-hour concentrations is 94.7 µg/m$^3$, which is well below the AAQS of 196.5 µg/m$^3$
- $PM_{10}$ Concentrations
  - H6H 24-hour and highest annual average concentrations are 72.9 and 22.4 µg/m$^3$, respectively, which are below the 24-hour and annual AAQS of 150 and 50 µg/m$^3$, respectively
- $PM_{2.5}$ Concentrations
  - 5-year average of the 98$^{th}$ percentile of the maximum 24-hour concentrations is 19.2 µg/m$^3$, which is below the AAQS of 35 µg/m$^3$
  - 5-year average of the highest annual concentrations is 7.5 µg/m$^3$, which is below the AAQS of 15 µg/m$^3$
- $NO_2$ Concentrations:
  - 5-year average of the 98$^{th}$ percentile of the maximum daily 1-hour concentrations is 77.5 µg/m$^3$, which is well below the AAQS of 189 µg/m$^3$

### *6.10.4 PSD Class II Increment Analyses*

A summary of the results of the modeling analyses, to demonstrate compliance with the PSD Class II increments, is presented in Table 6-12. The maximum predicted concentrations are as follows:

- $SO_2$ Concentrations
  - HSH 24-hour concentration is 27.9 µg/m$^3$, which is well below the PSD Class II increment of 91 µg/m$^3$
- $PM_{10}$ Concentrations
  - H2H 24-hour and highest annual average concentrations are 9.6 and 2.4 µg/m$^3$, respectively, which are below the PSD Class II increments of 30 and 17 µg/m$^3$, respectively
- $PM_{2.5}$ Concentrations
  - H2H 24-hour and highest annual average concentrations are 7.6 and 1.1 µg/m$^3$, respectively, which are below the PSD Class II increments of 9 and 4 µg/m$^3$, respectively

## 6.11 Conclusions

Based on the air quality modeling analyses, the maximum pollutant concentrations due to the proposed HEF facility are predicted to be less than the PSD Class II significant impact levels for all pollutants except for the 1-hour and 24-hour $SO_2$ impacts; 24-hour and annual $PM_{10}$ impacts; 24-hour and annual $PM_{2.5}$ impacts; and 1-hour $NO_2$ impacts. Based on the PSD Class I significant impact analysis, the maximum pollutant concentrations due to the proposed facility at the ENP are predicted to be less than the PSD Class I significant impact levels. As a result, more detailed $SO_2$, $PM_{10}$, $PM_{2.5}$, and $NO_2$ modeling analyses were performed with background sources to address compliance with the AAQS and PSD Class II increments. The results of the air modeling analyses demonstrate that the proposed project will comply with all applicable AAQS and PSD increments.

## 7.0 ADDITIONAL IMPACT ANALYSIS

This section presents the impacts that the proposed HEF project will have on associated growth; impacts to vegetation, soils, and visibility in the vicinity of the HEF site; and impacts at the PSD Class I area of the ENP related to AQRVs. Specifically, this section addresses FDEP Rules 62-212.400(4)(e), (8)(a) and (b), and (9), F.A.C. These rules are:

> (4) Source Information. (e) The air quality impacts, and the nature and extent of any or all general commercial, residential, industrial, and other growth which has occurred since August 7, 1977, in the area the source or modification would affect.
>
> (8) Additional Impact Analyses.
>
> (a) The owner or operator shall provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the source or modification and general commercial, residential, industrial and other growth associated with the source or modification. The owner or operator need not provide an analysis of the impact on vegetation having no significant commercial or recreational value.
>
> (b) The owner or operator shall provide an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial and other growth associated with the source or modification.
>
> (9) Sources Impacting Federal Class I Areas. Sources impacting Federal Class I areas are subject to the additional requirements provided in 40 CFR 52.21(p), adopted by reference in Rule 62-204.800, F.A.C.

## 7.1 Historical Growth and Impacts Due to Associated Growth

### *7.1.1 Introduction*

The general trends in residential, commercial, industrial, and other growth that has occurred in Highlands County since August 7, 1977, are presented in Subsections 7.1.2 through 7.1.4. Information is presented from a variety of available sources (i.e., Florida Statistical Abstract, FDEP, etc.) that characterize Highlands County as a whole. Information on air emissions and air quality obtained from FDEP and EPA is presented in Subsection 7.1.5.

The growth analysis in Subsection 7.1.6 considers the air quality impacts due to emissions resulting from the industrial, commercial, and residential growth associated with the proposed construction and operation of the proposed HEF project. The information and analysis is consistent with the EPA Guidance related to this requirement in the *Draft New Source Review Workshop Manual* (EPA, 1990).

The Site is located in the eastern portion of Highlands County and is surrounded by citrus groves. Highlands County is bounded by Glades County to the south, DeSoto and Hardee Counties to the west, Polk County to the north, and Okeechobee County to the east. Highlands County is a large county in Florida in land area, comprising approximately 1,100 square miles.

### 7.1.2 Residential Growth

***Population and Household Trends***

As an indicator of residential growth, the trends in the population and number of household units in Highlands County since 1978 are shown in Figure 7-1. The county experienced a 123-percent increase in population for the years 1978 through 2009. During this period, there was an increase in population of about 55,013. Similarly, the number of households in the county increased since 1977 by about 24,128, or 127 percent.

### 7.1.3 Commercial Growth

***Retail Trade and Wholesale Trade***

As an indicator of commercial growth in Highlands County, the trends in the number of commercial facilities and employees involved in retail and wholesale trade are presented in Figure 7-2. The retail trade sector comprises establishments engaged in retailing merchandise. The retailing process is the final step in the distribution of merchandise. Retailers are, therefore, organized to sell merchandise in small quantities to the general public. The wholesale trade sector comprises establishments engaged in wholesaling merchandise. This sector includes merchant wholesalers who buy and own the goods they sell, manufacturers' sales branches and offices that sell products manufactured domestically by their own company, and agents and brokers who collect a commission or fee for arranging the sale of merchandise owned by others.

From 1988 to 2009, retail trade in Highlands County has decreased by 4 establishments and 334 employees, or 1 and 7 percent, respectively. For the same period, wholesale trade has increased in the county by 53 establishments and 148 employees, or 83 and 35 percent, respectively.

***Labor Force***

The trend in the labor force in Highlands County since 1985 is shown in Figure 7-3. The sectors employing the largest number of persons in Highlands County have been in services, retail trade, and administration and support. Between 1985 and 2009, approximately 17,428 persons were added to the available work force, for an increase of 94 percent.

***Tourism***

Another indicator of commercial growth in Highlands County is the tourism industry. As an indicator of tourism growth in the county, the trend in the number of hotels and motels and the number of units at the hotels and motels are presented in Figure 7-4.

This industry comprises establishments primarily engaged in marketing and promoting communities and facilities to businesses and leisure travelers through a range of activities, such as assisting organizations in locating meeting and convention sites; providing travel information on area attractions, lodging accommodations, and restaurants; providing maps; and organizing group tours of local historical, recreational, and cultural attractions.

Between 1987 and 2010, there was no change in the number of hotels and motels in the county; however, there was an increase of 36 percent in the number of units at those facilities.

***Transportation***

As an indicator of transportation growth, the trend in the number of vehicle miles traveled (VMT) by motor vehicles on major roadways in Highlands County is presented in Figure 7-5. The county's main arteries are SR 98, SR 70, and U.S 27, which run east-west and north-south, respectively, through the county.

The existing commercial and transportation infrastructure should be adequate to provide any support services that might be required during construction and operation of the HEF. The workforce needed to operate the proposed facility represents a small fraction of the labor force present in the immediate and surrounding areas.

### 7.1.4 Industrial Growth

***Manufacturing and Agricultural Industries***

As an indicator of industrial growth, the trend in the number of employees in the manufacturing industry in Highlands County since 1987 is shown in Figure 7-6. As shown, the manufacturing industry experienced a 45 percent decrease in manufacturing employment from 1987 through 2009.

As another indicator of industrial growth, the trend in the number of employees in the agricultural industry, including sugar, in Highlands County since 1978 is also shown in Figure 7-6. As shown, the agricultural industry experienced a slight decrease in employment of 3 percent from 1987 through 2008.

***Utilities***

As an indicator of electrical utility growth, the electrical generation capacity in Highlands County since 1977 is shown in Figure 7-7.

### 7.1.5 Air Quality Discussion

***Air Emissions from Stationary Sources***

Based on actual emissions reported for the most recent year of available (2008, 2009, or 2010) from FDEP, total emissions from permitted stationary air sources in Highlands County are as follows:

- $SO_2$: 316 TPY
- $PM_{10}$: 20 TPY
- $NO_x$: 546 TPY
- CO: 87 TPY
- VOC: 63 TPY

Complete VOC emissions data was not available. VOC emissions were estimated based on about 10 percent of the total $NO_x$ and CO emissions.

***Air Emissions from Mobile Sources***

The trends in the air emissions of CO, VOC, and $NO_x$ from mobile sources in Highlands County are presented in Figure 7-8. Between 1990 and 2009, there were significant decreases in emissions of CO and a slight decrease in VOC and $NO_x$ emissions. The decrease in emissions were estimated at 51.1 TPD of CO, 3.9 TPD VOC, and 2.4 TPD of $NO_x$, which represent decreases from 1977 emissions of 64, 60, and 36 percent, respectively. Total emissions from mobile sources estimated for 2009 are 10,293 TPY for CO, 949 TPY for VOCs, and 1,533 TPY for $NO_x$.

***Air Monitoring Data***

Since 1977, Highlands County has been classified as attainment or maintenance for all criteria pollutants. Limited air quality monitoring data has been collected in Highlands County, only historical $O_3$ data was found in Lake Placid. For this evaluation, the air quality monitoring data collected at the monitoring stations nearest to the HEF site were used to assess air quality trends since 1977. Air quality monitoring data were based on the following monitoring stations:

Since 1988, PM has been measured at the air monitoring stations in the form of $PM_{10}$ due to the promulgation of the $PM_{10}$ AAQS. Prior to 1988, the AAQS for PM was in the form of TSP concentrations, and this form was measured at the stations.

Data collected from monitoring stations located in nearby counties are considered to be generally representative of air quality in Highlands County. Because these monitoring stations are generally located in more urbanized areas than the HEF area, the reported concentrations are likely to be somewhat higher than that experienced at the site.

These data indicate that the maximum air quality concentrations currently measured in the region comply with and are well below the applicable AAQS. These monitoring stations are located in areas where the highest concentrations of a measured pollutant are expected due to the combined effect of emissions from stationary and mobile sources, as well as the effects of meteorology. Therefore, the ambient concentrations in areas not monitored are expected to have pollutant concentrations less than the monitored concentrations from these sites.

***$SO_2$ Concentrations***

The trends in the annual, 24-hour, 3-hour, and 1-hour average $SO_2$ concentrations measured near the HEF Site since 1975 to 2010 are presented in Figures 7-9 through 7-12, respectively. $SO_2$ concentrations have been measured at eight stations for various time periods throughout these years. As shown in these figures, except for two years at the Mulberry (Polk County) monitor, concentrations have been and continue to be well below the AAQS.

It should be noted that limited data was available for comparison to the 1-hour $SO_2$ standard. To show a more detailed history, 1-hour second highest concentrations were summarized in Figure 7-12a, however, limited data in a the form of the 1-hour standard (99$^{th}$ percentile of the daily maximum 1-hour values) is presented in Figure 7-12b and compared to the AAQS.

***$PM_{10}$ Concentrations***

The trends in the annual and 24-hour average $PM_{10}$ and TSP concentrations since 1975 are presented in Figures 7-13a and 7-13b, respectively. TSP concentrations are presented through 1988, since the AAQS was based on TSP concentrations through that year. In 1988, the TSP AAQS was revoked, and the PM standard was revised to $PM_{10}$. As shown in these figures, measured TSP concentrations were generally below the TSP AAQS.

Since 1988, when $PM_{10}$ measurements began, the $PM_{10}$ concentrations have been and continue to be below the AAQS.

***$PM_{2.5}$ Concentrations***

The trends in annual and 24-hour average $PM_{2.5}$ concentrations since 1999 are presented in Figures 7-14a and 7-14b, respectively. As shown in the figures, aside from two years at the Hillsborough county monitor, measured $PM_{2.5}$ concentrations have been and continue to be below the AAQS.

***NO$_2$ Concentrations***

The trends in the annual and 1-hour average $NO_2$ concentrations measured at the nearest monitors to the HEF Site are presented in Figures 7-15a, and 7-15b and 7-15c, respectively. As shown in these figures, measured $NO_2$ concentrations have generally been well below the AAQS.

It should be noted that limited data was available for comparison to the 1-hour $NO_2$ standard. To show a more detailed history, 1-hour second highest concentrations were summarized in Figure 7-15b, however, limited data in the form of the 1-hour standard (98$^{th}$ percentile of the daily maximum 1-hour values) is presented in Figure 7-15c and compared to the AAQS.

***CO Concentrations***

The trends in the 1- and 8-hour average CO concentrations since 1977 are presented in Figures 7-16 and 7-17, respectively. As shown in these figures, measured CO concentrations have generally been well below the AAQS.

***O$_3$ Concentrations***

The trends in the 1-hour average $O_3$ concentrations since 1977 are presented in Figure 7-18. The 8-hour average $O_3$ concentrations are presented in Figure 7-19. As shown in these figures, the measured $O_3$ concentrations have generally been below the AAQS.

### *7.1.6 Impacts of Associated Growth*

Construction of the HEF facility will occur over approximately 12 to 18 months and will require an average of approximately 500 to 1,000 workers during that time. It is anticipated that many of these construction personnel will commute to the site. A total of about 60 additional permanent workers will be employed for the operation of the facility. Both the construction and permanent jobs are all new jobs created within Highlands County. However, the workforce needed to construct and operate the facility represents a small fraction of the population already present in the immediate area. Therefore, while there would be a small increase in vehicular traffic in the area, the effect on air quality levels would be minimal.

There are also expected to be no air quality impacts due to associated commercial and industrial growth, given the location of the HEF site. The existing commercial and industrial infrastructure is adequate to provide any support services that facility might require and would not increase with the operation of the facility. The addition of the HEF project will have a small positive effect on the increase of growth in the area. However, the surrounding area will certainly remain agricultural in the future.

The air quality data measured in the region of the HEF site indicates that the maximum air quality concentrations are well below the AAQS. Based on the trends presented of these maximum concentrations, the air quality has generally improved in the region since the PSD baseline date of August 7, 1977. As demonstrated in Section 6.0, the maximum air quality impacts resulting from the HEF facility are predicted to be low and for some pollutants and averaging times, below the significant impact levels. The cumulative 24-hour and annual average $PM_{10}$, 24-hour and annual $PM_{2.5}$, and 1-hour and 24-hour average $SO_2$, and 1-hour $NO_2$ impacts predicted demonstrate that the HEF facility and background sources will comply with the PSD increments and AAQS. As a result, the air quality concentrations in the region are expected to remain below the AAQS when the HEF facility becomes operational.

## 7.2 Potential Air Quality Effect Levels on Soils, Vegetation and Wildlife

### *7.2.1 Soils*

The potential and hypothesized effects of atmospheric deposition on soils include:

- Increased soil acidification
- Alteration in cation exchange
- Loss of base cations
- Mobilization of trace metals

The potential sensitivity of specific soils to atmospheric inputs is related to two factors. First, the physical ability of a soil to conduct water vertically through the soil profile is important in influencing the interaction with deposition. Second, the ability of the soil to resist chemical changes, as measured in terms of pH and soil cation exchange capacity (CEC), is important in determining how a soil responds to atmospheric inputs.

Soils in the vicinity of the HEF site are dominated by three soil series as identified in U.S. Department of Agriculture (USDA) Soil Survey of Highlands County: Astatula sand, 0- to 8-percent slopes; Paola sand, 0- to 8-percent slopes; and Paola-Basinger sands, rolling. These soils are described as follows:

- <u>Astatula sand, 0 to 8 percent slopes</u> – This nearly level to moderately sloping, excessively drained soil is in the ridge part of the county. This soil is the dominant soil on the ridge. The mapped areas are irregular in shape and range from 50 to more than 2,500 acres. The slopes are smooth to convex. Typically, the surface layer is dark grayish brown sand about 7-inches thick. The underlying material to a depth of 80 inches is brownish yellow sand. The available water capacity of this Astatula soil is very low. The permeability is very rapid. Depth to the water table is more than 80 inches. Most of the acreage of this soil is in citrus crops. A large part of the acreage has been developed for urban use. Small areas have been cleared for improved pasture grasses and cultivated crops. The natural vegetation consists of sand pine, longleaf pine, turkey oak, live oak, and hickory. The understory is scattered saw palmetto, sabal palmetto, bluestem, paspalum, cactus, and pineland threeawn.
- <u>Paola sand, 0 to 8 percent slopes</u> – This nearly level to moderately sloping, excessively drained soil is on high sandy ridges in the ridge part of the county. The mapped areas

are irregular in shape and range from 25 to more than 500 acres. The slopes are smooth to convex. Typically, the surface layer is gray sand about 5-inches thick. The subsurface layer, to a depth of 17 inches, is light gray sand. The subsoil, to a depth of 27 inches, is very pale brown and yellowish brown sand. The substratum to a depth of 80 inches or more is yellowish brown and yellow sand. The available water capacity of this Paola soil is very low. The permeability is very rapid. Depth to the water table is more than 80 inches. Most of the acreage of this soil is in citrus or natural vegetation. Some areas have been cleared for improved pasture and cultivated crops. The natural vegetation consists of sand pine, slash pine, turkey oak, scrub hickory, myrtle oak, Chapman oak, and sand live oak. The understory consists of scattered saw palmetto and pineland threeawn.

- Paola-Basinger sands, rolling – This highly pitted complex consists of nearly level to rolling, excessively drained soils on side slopes and ridge tops and poorly drained to very poorly drained soils in small depressional areas. The slopes are smooth to convex on the ridges and concave in the depressions and range from 0 to 12 percent. Basinger soil ranges from less than 1 acre to more than 10 acres, and Paola soil makes up the remaining acres in the map unit. This map unit is only in one area on the southeastern side of the ridge between Lake Placid and Florida State Highway 70. Typically, this soil has a surface layer of gray sand about 7-inches thick. The subsurface layer, to a depth of 17 inches, is light gray sand. The subsoil, to a depth of 27 inches, is very pale brown sand. The substratum to a depth more than 80 inches is yellowish brown and yellow sand. Basinger soil is in the pitted or depressional areas. Typically, the surface layer of this soil is dark gray fine sand about 6-inches thick. The upper part of the subsurface, to a depth of 16 inches, is light gray fine sand. The lower part, to a depth of 21 inches, is light brownish gray fine sand. The subsoil, to a depth of 52 inches, is brown fine sand. The upper part of the substratum, to a depth of 62 inches, is light brownish gray fine sand. The lower part to a depth of more than 80 inches is grayish brown loamy fine sand. Most of this map unit is in an urban subdivision; consequently, many areas have been altered by cutting, filling, or smoothing for present and future development. The available water capacity of Paola soil is very low. The permeability is very rapid. The water table is at a depth of more than 72 inches throughout the year. The available water capacity of Basinger soil is low. The permeability is rapid. The water table is at a depth of less than 12 inches during the summer rainy season. Some areas are ponded for a short period after heavy rainfall. The high water table impedes internal drainage. The natural vegetation on Paola soil consists of sand and slash pines, turkey oak, myrtle oak, Chapman oak, sand live oak, pignut hickory, scattered saw palmetto, and pineland threeawn. The natural vegetation on the Basinger soil is mostly St. John's Wort and some pineland threeawn, sand cordgrass, cutgrass, bluestem, maidencane, and pickerelweed. The present and intended use as an urban subdivision precludes the use of this land for cultivated crops, citrus crops, improved pasture, pine tree production, or rangeland.

### 7.2.2 *Vegetation*

The concentrations of the pollutants, duration of exposure, and frequency of exposure influence the response of vegetation to atmospheric pollutants. The pattern of pollutant exposure expected from the facility is that of a few episodes of relatively high ground-level concentration, which occur during certain meteorological conditions, interspersed with long periods of extremely low ground-level concentrations. If there are any effects of stack emissions on plants, they will be from the short-term, higher doses. A dose is the product of the concentration of the pollutant and duration of the exposure.

In general, the effects of air pollutants on vegetation occur primarily from $SO_2$, $NO_2$, $O_3$, and PM. Effects from minor air contaminants, such as fluoride, chlorine, hydrogen chloride, ethylene, ammonia, hydrogen sulfide, CO, and pesticides, have also been reported in the literature. The effects of air pollutants are dependent both on the concentration of the contaminant and the duration of the exposure. The term "injury," as opposed to damage, is commonly used to describe all plant responses to air contaminants and will be used in the context of this analysis. Air contaminants are thought to interact primarily with plant foliage, which is considered to be the major pathway of exposure.

Injury to vegetation from exposure to various levels of air contaminants can be termed acute, physiological, or chronic. Acute injury occurs as a result of a short-term exposure to a high contaminant concentration and is typically manifested by visible injury symptoms ranging from chlorosis (discoloration) to necrosis (dead areas). Physiological or latent injury occurs as the result of a long-term exposure to contaminant concentrations below those that result in acute injury symptoms. Chronic injury results from repeated exposure to low concentrations over extended periods of time, often without any visible symptoms, but with some effect on the overall growth and productivity of the plant. In this assessment, 100 percent of the particular air pollutant in the ambient air was assumed to interact with the vegetation, which is a very conservative approach.

***Sulfur Dioxide and Sulfuric Acid Mist***

Sulfur is an essential plant nutrient usually taken up as sulfate ions by the roots from the soil solution. When $SO_2$ in the atmosphere enters the foliage through pores in the leaves, it reacts with water in the leaf interior to form sulfite ions. Sulfite ions are highly toxic. They interact with enzymes, compete with normal metabolites, and interfere with a variety of cellular functions (Horsman and Wellburn, 1976). However, within the leaf, sulfite ions are oxidized to sulfate ions, which can then be used by the plant as a nutrient. Small amounts of sulfite may be oxidized before they prove harmful.

Observed $SO_2$ effect levels for several plant species and plant sensitivity groupings are presented in Tables 7-1 and 7-2, respectively. $SO_2$ gas at elevated levels has long been known to cause injury to plants. Acute $SO_2$ injury usually develops within a few hours or days of exposure, and symptoms include marginal, flecked, and/or intercostal necrotic areas that appear water-soaked and dullish green initially. This injury generally occurs to younger leaves. Chronic injury is usually evident by signs of chlorosis, bronzing, premature senescence, reduced growth, and possible tissue necrosis (EPA, 1982). Background levels of $SO_2$ range from 5.2 to 15.7 µg/m$^3$.

Many studies have been conducted to determine the effects of high-concentration, short-term $SO_2$ exposure on natural community vegetation. Sensitive plants include ragweed, legumes, blackberry, southern pine, and red and black oak. These species are injured by exposure to 3-hour $SO_2$

concentrations of 790 to 1,570 µg/m$^3$. Intermediate plants include locust and sweetgum. These species are injured by exposure to 3-hour $SO_2$ concentrations of 1,570 to 2,100 µg/m$^3$. Resistant species (injured at concentrations above 2,100 µg/m$^3$ for 3 hours) include white oak and dogwood (EPA, 1982).

A study of native Floridian species (Woltz and Howe, 1981) demonstrated that cypress, slash pine, live oak, and mangrove exposed to 1,300 µg/m$^3$ $SO_2$ for 8 hours were not visibly damaged. This finding supports the levels cited by other researchers on the effects of $SO_2$ on vegetation. Another study (McLaughlin and Lee, 1974) demonstrated that approximately 20 percent of a cross-section of plants ranging from sensitive to tolerant was visibly injured at 3-hour $SO_2$ concentrations of 920 µg/m$^3$. Jack pine seedlings exposed to $SO_2$ concentrations of 470 to 520 µg/m$^3$ for 24 hours demonstrated inhibition of foliar lipid synthesis; however, this inhibition was reversible (Malhotra and Kahn, 1978). Black oak exposed to 1,310 µg/m$^3$ $SO_2$ for 24 hours a day for 1 week demonstrated a 48 percent reduction in photosynthesis (Carlson, 1979).

$SO_2$ is considered to be the primary factor causing the death of lichens in most urban and industrial areas. The first indications of damage from $SO_2$ include the inhibition of nitrogen fixation, increased electrolyte leakage, and decreased photosynthesis and respiration, followed by discoloration and death of the algal component of the lichen (Fields, 1988). Sensitive species are damaged or killed by annual average levels of $SO_2$ ranging from 8 to 30 µg/m$^3$, and very few lichens can tolerate levels exceeding 125 µg/m$^3$ (Johnson 1979, DeWit 1976, Hawsworth and Rose 1970, LeBlanc, et al. 1972). In another study, two lichen species exhibited signs of $SO_2$ damage in the form of decreased biomass gain and photosynthetic rate as well as membrane leakage when exposed to concentrations of 200 to 400 µg/m$^3$ for 6 hours per week for 10 weeks (Hart, et al., 1988).

Acidic precipitation is formed from $SO_2$ emissions during the burning of primarily fossil fuels. This pollutant is oxidized to $SO_3$ in the atmosphere and dissolves in rain to form SAM, which falls as acidic precipitation (Ravera, 1989). Although concentration data are not available, SAM has been reported to yield necrotic spotting on the upper surfaces of leaves (Middleton, et. al., 1950).

***Nitrogen Dioxide***

$NO_2$ can injure plant tissue with symptoms usually appearing as irregular white to brown collapsed lesions between the leaf veins and near the margins. Conversely, non-injurious levels of $NO_2$ can be absorbed by plants, enzymatically transformed into ammonia, and incorporated into plant constituents such as amino acids (Matsumaru, et al., 1979).

For plants that have been determined to be more sensitive to $NO_2$ exposure than others, acute exposure (1, 4, and 8 hours) caused 5 percent predicted foliar injury at concentrations ranging from 3,800 to

15,000 μg/m$^3$ (Heck and Tingey, 1979). Chronic exposure of selected plants (some considered $NO_2$ sensitive) to $NO_2$ concentrations of 2,000 to 4,000 μg/m$^3$ for 213 to 1,900 hours caused reductions in yield of up to 37 percent and some chlorosis (Zahn, 1975). Short-term exposure to $NO_x$ at concentrations of 564 μg/m$^3$ caused adverse effects in lichen species (Holopainen and Karenlampi, 1984).

***Particulate Matter***

Although information pertaining to the effects of PM on plants is scarce, baseline concentrations are available (Mandoli and Dubey, 1988). Ten species of native Indian plants were exposed to levels of PM that ranged from 210 to 366 μg/m$^3$ for an 8-hour averaging period. Damage in the form of a higher leaf area/dry weight ratio was observed at varying degrees for most plants tested. Concentrations of PM lower than 163 μg/m$^3$ did not appear to be injurious to the tested plants.

***Carbon Monoxide***

Information pertaining to the effects of CO on plants is scarce. The main effect of high concentrations of CO is the inhibition of cytochrome *c* oxidase, the terminal oxidase in the mitochondrial electron transfer chain. Inhibition of cytochrome *c* oxidase depletes the supply of adenosine triphosphate (ATP), the principal donor of free energy required for cell functions. However, this inhibition only occurs at extremely high concentrations of CO. Pollok, et al. (1989) reported that exposure to a $CO:O_2$ ratio of 25 (equivalent to an ambient CO concentration of $6.85 \times 10^6$ μg/m$^3$) resulted in stomatal closure in the leaves of the sunflower (*Helianthus annuus*). Naik, et al. (1992) reported cytochrome *c* oxidase inhibition in corn, sorghum, millet, and Guinea grass at $CO:O_2$ ratios of 2.5 (equivalent to an ambient CO concentration of $6.85 \times 10^5$ μg/m$^3$). These plants were considered the species most sensitive to CO-induced inhibition of cytochrome *c* oxidase.

***Ozone***

$O_3$ can cause various damage to broad-leaved plants including: tissue collapse, interveinal necrosis, and markings on the upper surface leaves know as stippling (pigmented yellow, light tan, red brown, dark brown, red, or purple), flecking (silver or bleached straw white), mottling, chlorosis or bronzing, and bleaching. $O_3$ can also stunt plant growth and bud formation. On certain plants such as citrus, grape, and tobacco, it is common for leaves to wither and drop early.

### *7.2.3 Wildlife*

A wide range of physiological and ecological effects to fauna has been reported for gaseous and particulate pollutants (Newman, 1981; Newman and Schreiber, 1988). The most severe of these effects have been observed at concentrations above the secondary AAQS. Physiological and behavioral effects have been observed in experimental animals at or below these standards. For impacts on wildlife, the lowest threshold values of $SO_2$, $NO_x$, and particulates that are reported to cause physiological changes are shown in Table 7-3.

### *7.2.4 Impact Analysis Methodology*

A screening approach was used that compared the HEF project's maximum predicted ambient concentrations of air pollutants of concern in the vicinity of the site and the ENP PSD Class I Area with effect threshold limits for both vegetation and wildlife as reported in the scientific literature. A literature search was conducted to determine the effects of air contaminants on plant species as well as those species reported to occur in the vicinity of the site and in the PSD Class I area. It is recognized that effect threshold information is not available for all species found in these areas, although studies have been performed on a few of the common species and on other species known to be sensitive indicators of effects. Species of lichens, which are symbiotic organisms comprised of green or blue-green algae and fungi, have been used worldwide as air pollution monitors because relatively low levels of sulfur-, nitrogen-, and fluorine-containing pollutants adversely affect many species, altering lichen community composition, growth rates, reproduction, physiology, and morphological appearance (Blett et al., 2003).

## 7.3 Impacts on Soils, Vegetation, Wildlife, and Visibility in the Project's Vicinity

### *7.3.1 Impacts on Vegetation and Soils*

The primary vegetation, as well as agricultural crop, in the vicinity of the HEF is orange trees in citrus groves. The site is surrounded by orange groves for a large distance in all directions. Exotic species will colonize portions of the area, most notably melaleuca (*Melaleuca quinquenervia*) and Brazilian pepper (*Schinus terebinthifolius*), particularly within drainage features associated with the agricultural operations.

Soils in the area are primarily sandy soils. According to the modeling results presented in Section 6.0, the maximum air quality impacts due to the proposed HEF project are predicted to be below the AAQS and PSD increments. The AAQS were established to protect both public health and welfare. Public welfare is protected by the secondary AAQS, which Florida has adopted. Secondary standards set limits to protect public welfare, including protection against visibility impairment, damage to animals, crops, vegetation, and buildings (EPA, 2007).

Since the project's impacts on the local air quality are predicted to be less than the AAQS and less than the effect levels on soils and vegetation, the project's impacts on soils, vegetation, and wildlife in the vicinity of the site are expected to be negligible. With regard to $O_3$ concentrations, VOC and $NO_x$ emissions are precursors to $O_3$ formation, and the project's VOC and $NO_x$ emissions represent a small increase in VOC and $NO_x$ emissions for Highlands County. The facility's maximum VOC and $NO_x$ emissions are 123 and 185 TPY, respectively. The current County-wide VOC and $NO_x$ point source emissions (from Section 7.1.5) are approximately 63 TPY and 546 TPY, respectively. Total emissions from mobile sources estimated for 2009 are 949 TPY for VOCs and 1,533 TPY for $NO_x$. These emissions represent a significant small increase in total County-wide VOC and $NO_x$ emissions, however, the increase is much less compared to regional VOC and $NO_x$ emissions (i.e., from other surrounding counties).

### 7.3.2 *Impacts on Wildlife*

The major air quality risk to wildlife in the U.S. is from continuous exposure to pollutants above the NAAQS. This occurs in non-attainment areas (e.g., Los Angeles Basin). Risks to wildlife also may occur for wildlife living in the vicinity of an emission source that experiences frequent upsets or episodic conditions resulting from malfunctioning equipment, unique meteorological conditions, or startup operations (Newman and Schreiber, 1988). Under these conditions, chronic effects (e.g., particulate contamination) and acute effects (e.g., injury to health) have been observed (Newman, 1981).

Although air pollution impacts to wildlife have been reported in the literature, many of the incidents involved acute exposures to pollutants, usually caused by unusual or highly concentrated releases or unique weather conditions. As presented in Chapter 6, the predicted 1-hour $SO_2$ and $NO_2$ impacts are 94.7 μg/m$^3$ and 77.5 μg/m$^3$ which are 52 and 59 percent below the AAQS 1-hour limits of 196.5 μg/m$^3$ and 189 μg/m$^3$, respectively. The predicted 24-hour $PM_{2.5}$ and $PM_{10}$ impacts are 19.2 μg/m$^3$ and 72.9 μg/m$^3$ which are 45 and 51 percent below the AAQS 24-hour limits of 35 μg/m$^3$ and 150 μg/m$^3$, respectively. In addition, CO is predicted to be well below the significant impact levels which are considered trigger levels for the AAQS analysis, thus CO impacts are not expected to be significant. Compared to the AAQS, it is highly unlikely that emissions from HEF facility will cause adverse effects to wildlife due to the project's low impacts, which are predicted to be below the AAQS based on worst-case operation. Coupled with the mobility of wildlife, the potential for exposure of wildlife to the project's impacts is extremely unlikely.

## 7.4 Impacts to AQRVs in the ENP PSD Class I Area

### 7.4.1 *Identification of AQRVs and Methodology*

An AQRV analysis was conducted to assess the potential risk to AQRVs at the ENP due to the proposed emissions from the HEF facility. The ENP is the closest Class I area to the site, located approximately 147-km south of the HEF site.

The U.S. Department of the Interior in 1978 defined AQRVs to be:

> All those values possessed by an area except those that are not affected by changes in air quality and include all those assets of an area whose vitality, significance, or integrity is dependent in some way upon the air environment. These values include visibility and those

scenic, cultural, biological, and recreational resources of an area that are affected by air quality.

Important attributes of an area are those values or assets that make an area significant as a national monument, preserve, or primitive area. They are the assets that are to be preserved if the area is to achieve the purposes for which it was set aside (Federal Register, 1978).

The AQRVs include visibility, freshwater and coastal wetlands, dominant plant communities, unique and rare plant communities, soils and associated periphyton, and the wildlife dependent on these communities for habitat. Rare, endemic, threatened, and endangered species of the national park and bioindicators of air pollution (e.g., lichens) are also evaluated.

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

From HEF emissions presented in Table 6-2, the maximum potential emissions are estimated to be as follows using the highest emission rate for the short-term period and assuming 8,760 hours/year operation:

| Pollutant | Averaging Period | Maximum Emission Rate (lb/hr) | |
|---|---|---|---|
| | | **Units** | **Value** |
| $SO_2$ | 1-hour | lb/hr | 70.60 |
| $PM_{10}$ | 24-hour | lb/hr | 8.94 |
| $NO_x$ | 1-hour | lb/hr | 126.76 |
| $H_2SO_4$ | 24-hour | lb/hr | 3.15 |
| Total | | lb/hr | 209.4 |
| | | TPY | 917.4 |

The HEF site is located approximately 147 km from the PSD Class I area of the ENP. With Q as 917.4 TPY and D as 147 km, Q/D is equal to 6.2, well below the FLM criteria of 10. As a result, HEF is requesting an exemption from performing AQRV impact analyses.

# TABLES

**Table 2-1: Fuel Analysis, Highlands EnviroFuels**

| | Design Values | | | | | |
|---|---|---|---|---|---|---|
| | Sugarcane Bagasse | | Sorghum Bagasse | | Wood | |
| Parameter | As Fired | Dry Basis | As Fired | Dry Basis | (Dry Basis) | Natural Gas |
| Specific Gravity | – | – | – | – | – | – |
| Heating Value (Btu/lb) | 3,900 (as fired) | 7,800, dry | 3,900 (as fired) | 7,800, dry | 4,250, wet | – |
| Heating Value (Btu/gal) | – | – | – | – | – | – |
| Heating Value (Btu/scf) | – | – | – | – | – | 1,020 |
| Ultimate Analysis: | | | | | | |
| Carbon | 24.8 | 49.6 | 23 | 46 | 49.6 | – |
| Hydrogen | 3 | 6.0 | 2.75 | 5.5 | 5.87 | – |
| Nitrogen | 0.2 | 0.4 | 0.32 | 0.64 | 0.4 | – |
| Oxygen | 20.4 | 40.8 | 20.9 | 41.8 | 40.9 | – |
| Sulfur | 0.06 | 0.12 | 0.11 | 0.22 | 0.07 | – |
| Ash/Inorganic | 1.52 | 3.04 | 2.8 | 5.6 | 9 | – |
| Chlorine | 0.02 | 0.04 | 0.12 | 0.24 | 0.21 | – |
| Moisture | 50 | NA | 50 | NA | 30 - 50 | – |

Note: values represent average fuel characteristics, see Appendix A for detailed summary.

**Table 2-2: Biomass Boiler Design Parameters, Highlands EnviroFuels**

| Parameter | Value | Unit | Basis |
|---|---|---|---|
| **Boiler** | | | |
| Hours of Operation | 8,040 | hr/yr | Based on 335 days of operation |
| Maximum Steam 24-Hour | 250,000 | lb/hr | Highlands Ethanol |
| Maximum Steam 1-Hour | 275,000 | lb/hr | Based on 110% of 24-Hour steam rate |
| Net Enthalpy | 1,247.1 | Btu/lb | See Appendix A |
| Thermal Efficiency (Biomass) | 68 | % | Boiler manufacturer |
| Thermal Efficiency (Natural Gas) | 82 | % | Estimate |
| Total Heat Output Required | 2,506,671 | MMBtu/yr | Based on net enthalpy and 335 days/yr |
| **Sugar Cane Bagasse** | | | |
| Heating Value | 3,900 | Btu/lb, wet | See Appendix A |
| Heating Value | 7.8 | MMBtu/ton | Calculated |
| Sugarcane Harvested | 1,074,091 | Tons | Based on heat output requirement |
| Bagasse from Sugarcane | 22 | % | Fagen Engineering |
| Sugarcane Bagasse | 236,300 | Tons | Calculated |
| **Sweet Sorghum Bagasse** | | | |
| Heating Value | 3,900 | Btu/lb, wet | See Appendix A |
| Heating Value | 7.8 | MMBtu/ton | Calculated |
| Sweet Sorghum Harvested | 984,584 | Tons | Based on heat output requirement |
| Bagasse from Sweet Sorghum | 24 | % | Fagen Engineering |
| Sweet Sorghum Bagasse | 236,300 | Tons | Calculated |
| **Wood** | | | |
| Heating Value | 4,250 | Btu/lb, wet | See Appendix A |
| Heating Value | 8.5 | MMBtu/ton | Calculated |
| **Natural Gas** | | | |
| Heating Value | 1,020 | Btu/scf | See Appendix A |

**Table 2-3: Maximum Fuel Usage for the Biomass Boiler, Highlands EnviroFuels**

| Fuel Type | Heat Input[b] | Heat Output | Fuel Firing Rate | |
|---|---|---|---|---|
| **Maximum 1-hour/3-Hour[a]** | | | | |
| | (MMBtu/hr) | (MMBtu/hr) | | |
| Biomass - Sugarcane Bagasse | 504.3 | 343 | 64.66 | TPH |
| - Sorghum Bagasse | 504.3 | 343 | 64.66 | TPH |
| - Wood | 504.3 | 343 | 59.33 | TPH |
| Natural Gas | 249.0 | 204 | 244,118 | scf/hr |
| **Maximum 24-Hour[a]** | | | | |
| | (MMBtu/hr) | (MMBtu/hr) | | |
| Biomass - Sugarcane Bagasse | 458.5 | 312 | 58.78 | TPH |
| - Sorghum Bagasse | 458.5 | 312 | 58.78 | TPH |
| - Wood | 458.5 | 312 | 53.94 | TPH |
| Natural Gas | 249.0 | 204 | 244,118 | scf/hr |
| **Annual Average** | | | | |
| | (MMBtu/yr) | (MMBtu/yr) | | |
| Normal Operations (100% Bagasee Firing) | | | | |
| Sugarcane Bagasse | 1,843,140 | 1,253,336 | 236,300 | TPY |
| Sorghum Bagasse | 1,843,140 | 1,253,336 | 236,300 | TPY |
| Wood | 0 | 0 | 0 | TPY |
| Natural Gas | 0 | 0 | 0 | MMscf/yr |
| Total | 3,686,281 | 2,506,671 | | |
| Maximum Wood Firing (10%Wood / 90% Bagasse) | | | | |
| Sugarcane Bagasse | 1,658,826 | 1,128,002 | 212,670 | TPY |
| Sorghum Bagasse | 1,658,826 | 1,128,002 | 212,670 | TPY |
| Wood | 368,628 | 250,667 | 43,368 | TPY |
| Natural Gas | 0 | 0 | 0 | MMscf/yr |
| Total | 3,686,281 | 2,506,671 | | |
| Maximum Natural Gas Firing (30% Natural Gas / 70% Bagasse) | | | | |
| Sugarcane Bagasse | 1,215,145 | 826,299 | 155,788 | TPY |
| Sorghum Bagasse | 1,215,145 | 826,299 | 155,788 | TPY |
| Wood | 0 | 0 | 0 | TPY |
| Natural Gas | 1,041,553 | 854,074 | 1,021 | MMscf/yr |
| Total | 3,471,844 | 2,506,671 | | |

Notes:

[a] Maximum 3-hour heat input based on 275,000 lb/hr steam rate; maximum 24-hour based on 250,000 lb/hr. Fuels may be burned in combination, not to exceed total heat outputs.

[b] Heat input and output rates are calculated based on the design parameters shown in Table 2-2.

**Table 2-4: Specifications for VOL Storage Tanks**

| Tank Description<br>Tank ID No. | Fuel Ethanol Storage Tank<br>1 | 200 Proof Ethanol Storage Tank<br>2 | Off-Spec Tank<br>3 | Denaturant/Gasoline Tank<br>4 | Corrosion Inhibitor Tank<br>5 |
|---|---|---|---|---|---|
| Subpart Kb Applies (Yes/No) | Yes | Yes | Yes | Yes | No |
| Tank Content | Ethanol | Ethanol | Off-Spec Ethanol Product | Gasoline (4.5% of ethanol for denaturant) | Methanol, xylene and ethylbenzene |
| Tank Type | Internal Floating Roof | Internal Floating Roof | Internal Floating Roof | Internal Floating Roof | Vertical Fixed Roof |
| Tank Height (ft) | 52.0 | 32.0 | 32.0 | 32.0 | 8.0 |
| Tank Diameter (ft) | 58.0 | 25.0 | 25.0 | 25.0 | 7.0 |
| Tank Capacity (gallons) | 1,000,000 | 100,000 | 100,000 | 100,000 | 2,300 |
| Throughput (gal/yr) | 36,000,000 | 36,000,000 | 3,600,000 | 1,620,000 | 2,700 |
| Turnovers per Year | 36 | 360 | 36 | 16 | 1 |

[a] See MSDS in Appendix D for corrosion inhibitor speciation.

**Table 2-5: Ethanol Process: $CO_2$ and Distillation Scrubbers**

| | |
|---|---|
| **Manufacturer and Model No.** | Vogelbusch (or equivalent) |
| **$CO_2$ Scrubber** | |
| Inlet Flue Gas Temp (°F) | 77 |
| Inlet Design Flow Rate (acfm) | 4,566 |
| Scrubbing Liquid | Process Water |
| Scrubbing Liquid Flow Rate (gpm) | 64 |
| Recirculation Liquid Flow Rate (gpm) | 101 |
| Ethanol Removal Efficiency (%) | 98 |
| **Distillation Scrubber** | |
| Inlet Flue Gas Temp (°F) | 77 |
| Inlet Design Flow Rate (acfm) | 120 |
| Scrubbing Liquid | Soft Water |
| Scrubbing Liquid Flow Rate (gpm) | 4 |
| Ethanol Removal Efficiency (%) | 98 |

**Table 2-6: Boiler Control Equipment Parameters: Wet Sand Separator (Cyclone)**

| | |
|---|---|
| **Manufacturer and Model No.** | Wet Cyclone (or equivalent)[a] |
| Inlet Flue Gas Temp (°F) | 510 |
| Inlet Design Flue Gas Flow Rate (acfm) | 256,832 |
| Moisture (% Volume) | 18 |
| Cyclone Diameter (ft) | 22 |
| Cyclone Height (ft) | 35 |
| No. of Spray Nozzles (Cyclone) | 5 |
| No. of Spray Nozzles (Inlet Duct) | 9 |
| Total Water Flow to Nozzles (gpm) | 713 |
| Pressure Drop (in $H_2O$) | 9 |
| Overall PM Collection Efficiency (%) | 80 |

[a] Vendor for the Biomass Boiler Cyclone not yet selected.

**Table 2-7: Boiler Control Equipment Parameters: Electrostatic Precipitator**

| | | | |
|---|---|---|---|
| **Manufacturer and Model No.** | Factory Sales (or equivalent)[a] | | |
| | Model No.39R-1330-3712P | | |
| Inlet Flue Gas Temp (°F) | | | 510 |
| Inlet Design Flue Gas Flow Rate (acfm) | | | 256,832 |
| Moisture (% Volume) | | | 18 |
| Inlet PM Loading (lb/MMBtu) | | | 0.41 |
| No. of Precipitators | | | 1 |
| Precipitation Type | | | Rigid Electrode |
| Total Number of Fields | | | 4 |
| Total Installed Collection Area ($ft^2$) | | | 71,656 |
| Gas Velocity (ft/s) | | | 3.66 |
| Specific Collection Area ($ft^2$/1,000 acfm) | | | 279 |
| Power Consumption (kw) | | | 121 |
| Pressure Drop (in $H_2O$) | | | 0.5 |
| **Pollutants** | **Inlet Loading (lb/MMBtu)** | **Outlet Loading (lb/MMBtu)** | **Control Efficiency %** |
| Particulate Matter | 0.41 | 0.015 | 96.3 |

[a] Vendor for the Biomass Boiler ESP not yet selected.



Golder Associates

**Table 2-8: Boiler Control Equipment Parameters: Selective Non-Catalytic Reduction System**

| | | | |
|---|---|---|---|
| **Manufacturer and Model No.** | DNT[a] (or equivalent) | | |
| Flue Gas Flow Rate (acfm) | | | 256,832 |
| $NO_x$ Reduction Reagent | | | 19% Ammonia |
| Ammonia Injectors | | | 6 |
| Ammonia Flow Control Section | | | 1 |
| Pressure Drop (in of wc) | | | 0.8 |
| **Pollutants** | **Inlet Loading (lb/MMBtu)** | **Outlet Loading (lb/MMBtu)** | **Control Efficiency %** |
| Nitrogen Oxides | 0.25 | 0.10 | 60 |

Notes:

[a] Vendor for the Biomass Boiler SNCR system not yet selected.

**Table 2-9: Boiler Control Equipment Parameters: Dry Sorbent Injection System**

| | | | |
|---|---|---|---|
| **Manufacturer and Model No.** | Factory Sales (or equivalent)[a] | | |
| | Model No. T-268 | | |
| Inlet Flue Gas Temp ($^oF$) | | | 510 |
| Inlet Design Flue Gas Flow Rate (acfm) | | | 256,832 |
| Moisture (% Volume) | | | 18 |
| No. of Injection Fans | | | 1 |
| No. of Feed Hoppers | | | 1 |
| No. of Pulverizers | | | 1 |
| No. of Classifiers | | | 1 |
| Reagent | | | Trona or sodium bicarbonate |
| Dry Sorbent Injection Rate (lb/hr) | | | 219 |
| Pulverizer Motor (hp) | | | 40 |
| Classifier Motor (hp) | | | 8 |
| Blower Motor (hp) | | | 20 |
| **Pollutants** | **Inlet Loading (lb/hr)** | **Outlet Loading (lb/hr)** | **Control Efficiency %** |
| HCl | 37 | 1.8 | 79 |
| $SO_2$ | 64 | 16.0 | 75 |

[a] Vendor for the Biomass Boiler Acid Gas Removal System not yet selected.

**Table 2-10: Physical, Performance, and Emissions Data for the Fermentation $CO_2$ Scrubber**

| Parameter | Value [a] | Basis |
|---|---|---|
| Performance Data | | |
| Ethanol Production (gal/yr) | 36,000,000 | Highlands Envirofuels |
| Ethanol Production (gal/day) | 120,000 | Estimated |
| Scrubbing Column Control Efficiency (%) | 98.0 | Design Value |
| Hours of Operation | 7,296 | Maximum |
| Emission Factors[a] | | |
| Uncontrolled Ethanol (lb/hr) | 770.4 | Design Value |
| Controlled Ethanol (lb/hr) | 15.41 | Calculated |
| Uncontrolled Other VOCs - Total (lb/hr) | 180.0 | Calculated |
| Controlled Other VOCs - Total (lb/hr) | 3.60 | Design Value |

Emission Calculation - Speciated [a,b]

| Pollutant | Factor (%) | Description | Maximum Uncontrolled Emissions (lb/hr) | Maximum Uncontrolled Emissions (TPY) | Maximum Controlled Emissions (lb/hr) | Maximum Controlled Emissions (TPY) |
|---|---|---|---|---|---|---|
| Ethanol | 100.0 | of ethanol | 770.4 | 2,810.4 | 15.41 | 56.21 |
| Ethyl Acetate | 78.0 | of other VOCs | 140.4 | 512.2 | 2.81 | 10.24 |
| Acetaldehyde[c] | 19.8 | of other VOCs | 35.6 | 130.0 | 0.71 | 2.60 |
| Methanol [c] | 2.2 | of other VOCs | 4.0 | 14.4 | 0.079 | 0.29 |
| | | **Total VOC** | **950.4** | **3,467.1** | **19.01** | **69.34** |
| | | **Total HAP** | **39.6** | **144.5** | **0.79** | **2.89** |

[a] Based on data from Highlands EnviroFuels, 2011.

[b] Example Calculation - Ethyl Acetate:

*Hourly Average: 3.6 lb/hr Total Controlled Other VOCs x (78 % Maximum of VOC / 100) = 2.81 lb/hr Ethyl Acetate*

*Annual Average: 2.81 lb/hr Ethyl Acetate x 7,296 hr/yr / 2,000 lb/hr = 10.24 TPY Ethyl Acetate*

[c] Hazardous Air Pollutants (HAP).

**Table 2-11: Physical, Performance, and Emissions Data for the Distillation Vent Scrubber**

| Parameter | Value [a] | Basis |
|---|---|---|
| <u>Performance Data</u> | | |
| Ethanol Production (gal/yr) | 36,000,000 | Highlands Envirofuels |
| Ethanol Production (gal/day) | 120,000 | Estimated |
| Scrubbing Column Control Efficiency (%) | 98 | Design Value |
| Hours of Operation | 7,296 | Maximum |
| <u>Emission Factors[a]</u> | | |
| Uncontrolled Ethanol (lb/hr) | 79.20 | Design Value |
| Controlled Ethanol (lb/hr) | 1.58 | Calculated |
| Uncontrolled Other VOCs - Total (lb/hr) | 1.20 | Design Value |
| Controlled Other VOCs - Total (lb/hr) | 1.20 | Design Value |

<u>Emission Calculation - Speciated [a,b]</u>

| | | | Maximum Uncontrolled Emissions | | Maximum Controlled Emissions | |
|---|---|---|---|---|---|---|
| Pollutant | Factor (%) | Description | (lb/hr) | (TPY) | (lb/hr) | (TPY) |
| Ethanol | 100.0 | of ethanol | 79.20 | 288.92 | 1.58 | 5.78 |
| Ethyl Acetate | 78.0 | of other VOCs | 0.94 | 3.41 | 0.94 | 3.41 |
| Acetaldehyde[c] | 19.8 | of other VOCs | 0.24 | 0.87 | 0.24 | 0.87 |
| Methanol [c] | 2.2 | of other VOCs | 0.026 | 0.096 | 0.026 | 0.096 |
| | | **Total VOC** | **80.4** | **293.3** | **2.78** | **10.16** |
| | | **Total HAP** | **0.26** | **0.96** | **0.26** | **0.96** |

[a] Based on data from Highlands EnviroFuels, 2011.

[b] Example Calculation - Ethyl Acetate:

*Hourly Average: 1.2 lb/hr Total Controlled Other VOCs x (78 % Maximum of VOC / 100) = 0.94 lb/hr Ethyl Acetate*

*Annual Average: 0.94 lb/hr Ethyl Acetate x 7,296 hr/yr / 2,000 lb/hr = 3.41 TPY Ethyl Acetate*

[c] Hazardous Air Pollutants (HAP).

Table 2-12: Maximum Short-Term Emissions for the Biomass Boiler, Highlands EnviroFuels

| Regulated Pollutant | Sugarcane Bagasse Emission Factor [a] (lb/MMBtu) | Sugarcane Bagasse Activity Factor [b] (MMBtu/hr) | Sugarcane Bagasse Maximum Emissions (lb/hr) | Sweet Sorghum Bagasse Emission Factor [a] (lb/MMBtu) | Sweet Sorghum Bagasse Activity Factor [b] (MMBtu/hr) | Sweet Sorghum Bagasse Maximum Emissions (lb/hr) | Wood Emission Factor [a] (lb/MMBtu) | Wood Activity Factor [b] (MMBtu/hr) | Wood Maximum Emissions (lb/hr) | Natural Gas Emission Factor [a] (lb/MMBtu) | Natural Gas Activity Factor (MMBtu/hr) | Natural Gas Maximum Emissions (lb/hr) | Maximum Emissions for all fuels (lb/hr) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1-hr Averages | | | | | | | | | | | | | |
| Sulfur Dioxide [j] | 0.078 | 504 | 39.1 | 0.14 | 504 | 70.6 | 0.075 | 504 | 37.8 | 0.00059 [d] | 249 | 0.15 | 70.6 |
| Nitrogen Oxides (uncontrolled) | 0.25 | 504 | 126.1 | 0.25 | 504 | 126.1 | 0.25 | 504 | 126.1 | 0.14 [d] | 249 | 34.18 | 126.1 |
| Carbon Monoxide (cold-startup) | 3.0 [e] | 183 | 550.2 | 6.5 [e] | 183 | 1,192.1 | 6.5 [e] | 183 | 1,192.1 | 0.00059 [d] | 249 | 0.15 | 1,192.1 |
| 3-hr Averages | | | | | | | | | | | | | |
| Particulate (PM) | 0.015 | 504 | 7.6 | 0.015 | 504 | 7.6 | 0.015 | 504 | 7.6 | 0.0075 [d] | 249 | 1.9 | 7.6 |
| Particulate ($PM_{10}$) | 0.015 | 504 | 7.6 | 0.015 | 504 | 7.6 | 0.015 | 504 | 7.6 | 0.0075 [d] | 249 | 1.9 | 7.6 |
| Particulate ($PM_{2.5}$) [c] | 0.0098 | 504 | 4.9 | 0.0098 | 504 | 4.9 | 0.0098 | 504 | 4.9 | 0.0075 [d] | 249 | 1.9 | 4.9 |
| Sulfur Dioxide [j] | 0.078 | 504 | 39.1 | 0.14 | 504 | 70.6 | 0.075 | 504 | 37.8 | 0.00059 [d] | 249 | 0.15 | 70.6 |
| Nitrogen Oxides (uncontrolled) | 0.25 | 504 | 126.1 | 0.25 | 504 | 126.1 | 0.25 | 504 | 126.1 | 0.14 [d] | 249 | 34.18 | 126.1 |
| Carbon Monoxide (cold-startup) | 3.0 [e] | 183 | 550.2 | 6.5 [e] | 183 | 1,192.1 | 6.5 [e] | 183 | 1,192.1 | 0.082 [d] | 249 | 20.5 | 1,192.1 |
| VOC | 0.017 | 504 | 8.6 | 0.017 | 504 | 8.6 | 0.017 | 504 | 8.6 | 0.0054 [d] | 249 | 1.34 | 8.6 |
| Lead | 9.60E-05 [i] | 504 | 0.048 | 9.60E-05 [i] | 504 | 0.048 | 8.4E-05 [i] | 504 | 0.042 | 4.9E-07 [d] | 249 | 1.2E-04 | 0.048 |
| Mercury | 1.38E-05 [i] | 504 | 0.0070 | 1.38E-05 [i] | 504 | 0.0070 | 3.6E-06 [i] | 504 | 0.0018 | 2.5E-07 [d] | 249 | 6.3E-05 | 0.0070 |
| Fluorides | 6.0E-04 [f] | 504 | 0.30 | 6.0E-04 [f] | 504 | 0.30 | 6.0E-04 [f] | 504 | 0.30 | -- | 249 | -- | 0.30 |
| Sulfuric Acid Mist [g] | 0.0038 | 504 | 1.9 | 0.0069 | 504 | 3.5 | 0.0037 | 504 | 1.9 | 2.9E-05 | 249 | 7.2E-03 | 3.46 |
| Ammonia [h] | 0.018 | 504 | 8.8 | 0.018 | 504 | 8.8 | 0.018 | 504 | 8.8 | 0.018 | 249 | 4.4 | 8.8 |
| 24-hr Averages | | | | | | | | | | | | | |
| Particulate (PM) | 0.015 | 458 | 6.9 | 0.015 | 458 | 6.9 | 0.015 | 458 | 6.9 | 0.0075 [d] | 249 | 1.9 | 6.9 |
| Particulate ($PM_{10}$) | 0.015 | 458 | 6.9 | 0.015 | 458 | 6.9 | 0.015 | 458 | 6.9 | 0.0075 [d] | 249 | 1.9 | 6.9 |
| Particulate ($PM_{2.5}$) [c] | 0.0098 | 458 | 4.5 | 0.0098 | 458 | 4.5 | 0.0098 | 458 | 4.5 | 0.0075 [d] | 249 | 1.9 | 4.5 |
| Sulfur Dioxide [j] | 0.078 | 458 | 35.5 | 0.14 | 458 | 64.2 | 0.075 | 458 | 34.4 | 0.00059 [d] | 249 | 0.15 | 64.2 |
| Nitrogen Oxides | 0.10 | 458 | 45.8 | 0.10 | 458 | 45.8 | 0.10 | 458 | 45.8 | 0.10 | 249 | 24.90 | 45.8 |
| Carbon Monoxide (cold-startup) | 3.0 [e] | 183 | 550.2 | 6.5 [e] | 183 | 1,192.1 | 6.5 [e] | 183 | 1,192.1 | 0.082 [d] | 249 | 20.5 | 1,192.1 |
| VOC | 0.017 | 458 | 7.8 | 0.017 | 458 | 7.8 | 0.017 | 458 | 7.8 | 0.0054 [d] | 249 | 1.34 | 7.8 |
| Lead | 9.60E-05 [i] | 458 | 0.044 | 9.60E-05 [i] | 458 | 0.044 | 8.4E-05 [i] | 458 | 0.039 | 4.9E-07 [d] | 249 | 1.2E-04 | 0.044 |
| Mercury | 1.38E-05 [i] | 458 | 0.0063 | 1.38E-05 [i] | 458 | 0.0063 | 3.6E-06 [i] | 458 | 0.0017 | 2.5E-07 [d] | 249 | 6.3E-05 | 0.0063 |
| Fluorides | 6.0E-04 [f] | 458 | 0.28 | 6.0E-04 [f] | 458 | 0.28 | 6.0E-04 [f] | 458 | 0.28 | -- | 249 | -- | 0.28 |
| Sulfuric Acid Mist [g] | 0.0038 | 458 | 1.7 | 0.00686 | 458 | 3.1 | 0.003675 | 458 | 1.7 | 2.9E-05 | 249 | 7.2E-03 | 3.15 |
| Ammonia [h] | 0.018 | 458 | 8.0 | 0.018 | 458 | 8.0 | 0.018 | 458 | 8.0 | 0.018 | 249 | 4.4 | 8.0 |
| 30-day Rolling Averages | | | | | | | | | | | | | |
| Sulfur Dioxide [j] | 0.078 | 458 | 35.5 | 0.14 | 458 | 64.2 | 0.075 | 458 | 34.4 | 0.00059 [d] | 249 | 0.15 | 64.2 |
| Nitrogen Oxides | 0.10 | 458 | 45.8 | 0.10 | 458 | 45.8 | 0.10 | 458 | 45.8 | 0.10 | 249 | 24.9 | 45.8 |
| Carbon Monoxide | 0.30 | 458 | 137.5 | 0.30 | 458 | 137.5 | 0.30 | 458 | 137.5 | 0.082 [d] | 249 | 20.5 | 137.5 |
| Ammonia [h] | 0.018 | 458 | 8.0 | 0.018 | 458 | 8.0 | 0.018 | 458 | 8.0 | 0.018 | 249 | 4.4 | 8.0 |

Notes:

[a] Based on Proposed BACT limits, unless otherwise noted.

[b] Maximum 1-hour and 3-hour heat input based on 275,000 lb/hr steam; maximum 24-hour and 30-day rolling average heat input based on 250,000 lb/hr steam.

[c] Based on wood residue combustion, Section 1.6, AP-42, September 2003; 65 percent of PM emissions.

[d] Based on AP-42 emission factor for Natural Gas (Section 1.4, July 1998), divided by the heating value for natural gas (1,020 Btu/scf).

[e] Under cold startup conditions, boiler will be limited to 100,000 lb/hr of steam. Cold startup heat input rate is based on this limited steam rate.

[f] Based on highest stack test results for New Hope Power Company Boilers A, B, and C (1999-2002) excluding 1999 wood test for Unit C.

[g] Based on 4% of the $SO_2$ emissions becomes $SO_3$ from AP-42 for fuel oil burning; then convert to SAM (98/80).

[h] Ammonia emission rate of 30 ppmvd @ 7% $O_2$. Gas flow rate = 101,300 dscfm for 24-hour average. Other fuels based on same emissions factor (0.018 lb/MMBtu).

[i] Based on maximum sorghum fuel content, sorghum fuel analysis September 2009. Maximum values used. Assumed 90% control efficiency for Lead.

[j] Uncontrolled emission rates for $SO_2$ are 0.31 for sugarcane bagasse, 0.56 lb/MMBtu for sorghum bagasse, and 0.30 lb/MMBtu for wood.
A control efficiency of 75 percent is applied to all emisison rates, except those due to natural gas combustion.

**Table 2-13: Maximum Annual Emissions for the Biomass Boiler, Highlands EnviroFuels**

| | Sugarcane Bagasse | | | Sweet Sorghum Bagasse | | | Wood | | | Natural Gas | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Regulated Pollutant | Emission Factor [a] (lb/MMBtu) | Activity Factor ($10^{12}$ Btu/yr) | Annual Emissions (TPY) | Emission Factor [a] (lb/MMBtu) | Activity Factor ($10^{12}$ Btu/yr) | Annual Emissions (TPY) | Emission Factor [a] (lb/MMBtu) | Activity Factor ($10^{12}$ Btu/yr) | Annual Emissions (TPY) | Emission Factor [a] (lb/MMBtu) | Activity Factor ($10^{12}$ Btu/yr) | Annual Emissions (TPY) | Total Annual Emissions[c] (TPY) |
| Particulate (PM) | 0.015 | 1.843 | 13.8 | 0.015 | 1.843 | 13.8 | 0.015 | 0.000 | 0.0 | 0.0075 | 0.000 | 0.0 | 27.6 |
| Particulate ($PM_{10}$) | 0.015 | 1.843 | 13.8 | 0.015 | 1.843 | 13.8 | 0.015 | 0.000 | 0.0 | 0.0075 | 0.000 | 0.0 | 27.6 |
| Particulate ($PM_{2.5}$) | 0.010 | 1.843 | 9.0 | 0.010 | 1.843 | 9.0 | 0.010 | 0.000 | 0.0 | 0.0075 | 0.000 | 0.0 | 18.0 |
| Sulfur dioxide | 0.078 | 1.843 | 71.4 | 0.14 | 1.843 | 129.0 | 0.075 | 0.000 | 0.0 | 0.00059 | 0.000 | 0.0 | 200.4 |
| Nitrogen oxides | 0.10 | 1.843 | 92.2 | 0.10 | 1.843 | 92.2 | 0.10 | 0.000 | 0.0 | 0.10 | 0.000 | 0.0 | 184.3 |
| Carbon monoxide | 0.30 | 1.843 | 276.5 | 0.30 | 1.843 | 276.5 | 0.30 | 0.000 | 0.0 | 0.082 | 0.000 | 0.0 | 552.9 |
| VOC | 0.017 | 1.843 | 15.7 | 0.017 | 1.843 | 15.7 | 0.017 | 0.000 | 0.0 | 0.0054 | 0.000 | 0.0 | 31.3 |
| Lead | 9.60E-05 | 1.843 | 0.088 | 9.60E-05 | 1.843 | 0.088 | 8.4E-05 | 0.000 | 0.000 | 4.9E-07 | 0.000 | 0.0 | 0.18 |
| Mercury | 1.38E-05 | 1.843 | 0.0127 | 1.38E-05 | 1.843 | 0.0127 | 3.6E-06 | 0.000 | 0.0000 | 2.5E-07 | 0.000 | 0.0 | 0.025 |
| Fluorides | 6.0E-04 | 1.843 | 0.55 | 6.0E-04 | 1.843 | 0.55 | 6.0E-04 | 0.000 | 0.00 | -- | 0.000 | -- | 1.1 |
| Sulfuric acid mist[b] | 0.00380 | 1.843 | 3.50 | 0.00686 | 1.843 | 6.32 | 0.00368 | 0.000 | 0.00 | 2.9E-05 | 0.000 | 0.0 | 9.8 |
| Ammonia | 0.018 | 1.843 | 16.2 | 0.018 | 1.843 | 16.2 | 0.018 | 0.000 | 0.0 | 0.018 | 0.000 | 0.0 | 32.3 |

Notes:

[a] Refer to Table 2-12 for basis of emission factors.

[b] Based on 4% of the $SO_2$ emissions becomes $SO_3$ from AP-42 for fuel oil burning; then convert to SAM (98/80).

[c] Denotes maximum for any fuel combination.

Table 2-14: Short-Term Emissions of Hazardous Air Pollutants from the Biomass Boiler

| HAP | Sugarcane Bagasse Emission Factor (lb/MMBtu) | Ref | Activity Factor (MMBtu/hr) | Control Efficiency (%) | Hourly Emissions (lb/hr) | Sorghum Bagasse Emission Factor (lb/MMBtu) | Ref | Activity Factor (MMBtu/hr) | Control Efficiency (%) | Hourly Emissions (lb/hr) | Wood Emission Factor (lb/MMBtu) | Ref | Activity Factor (MMBtu/hr) | Control Efficiency (%) | Hourly Emissions (lb/hr) | Natural Gas Emission Factor (lb/10$^6$ scf) | Ref | Activity Factor (MMscf/hr) | Control Efficiency (%) | Hourly Emissions (lb/hr) | Maximum Emissions for All Fuels (lb/hr) | HAP |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Biomass Boiler** | | | | | | | | | | | | | | | | | | | | | | |
| Acetaldehyde | UD | 2 | 459 | | UD | UD | 2 | 459 | | UD | 8.3E-04 | 4 | 459 | | 0.38 | ND | | 0.24 | | ND | 0.38 | Acetaldehyde |
| Acetophenone | ND | | 459 | | ND | ND | | 459 | | ND | 3.2E-09 | 4 | 459 | | 1.47E-06 | ND | | 0.24 | | ND | 1.47E-06 | Acetophenone |
| Acrolein | UD | 2 | 459 | | UD | UD | 2 | 459 | | UD | 4.0E-03 | 4 | 459 | | 1.83 | ND | | 0.24 | | ND | 1.83 | Acrolein |
| Antimony | ND | | 459 | | ND | ND | | 459 | | ND | 7.90E-06 | 4 | 459 | | 0.0036 | ND | | 0.24 | | ND | 3.62E-03 | Antimony |
| Arsenic[a] | 2.05E-05 | 8 | 459 | 90 | 9.40E-04 | 2.05E-05 | 8 | 459 | 90 | 9.40E-04 | 1.13E-04 | 1 | 459 | 90 | 0.0052 | 2.00E-04 | 6 | 0.24 | 90 | 4.88E-06 | 5.18E-03 | Arsenic[a] |
| Benzene | 5.00E-03 | 2 | 459 | | 2.29 | 5.00E-03 | 2 | 459 | | 2.29 | 0.0042 | 4 | 459 | | 1.93 | 0.0021 | 6 | 0.24 | | 5.13E-04 | 2.29 | Benzene |
| Beryllium[a] | 3.85E-05 | 8 | 459 | 90 | 1.77E-03 | 3.85E-05 | 8 | 459 | 90 | 1.77E-03 | 5.09E-07 | 1 | 459 | 90 | 2.33E-05 | 1.20E-05 | 6 | 0.24 | 90 | 2.93E-07 | 1.77E-03 | Beryllium[a] |
| bis(2ethylhexyl)phthalate | 6.71E-04 | 2 | 459 | | 0.31 | 6.71E-04 | 2 | 459 | | 0.31 | 4.70E-08 | 4 | 459 | | 2.15E-05 | ND | | 0.24 | | ND | 0.31 | bis(2ethylhexyl)phthalate |
| Cadmium[a] | 3.33E-05 | 8 | 459 | 90 | 1.53E-03 | 3.33E-05 | 8 | 459 | 90 | 1.53E-03 | 4.10E-06 | 4 | 459 | 90 | 1.88E-04 | 0.0011 | 6 | 0.24 | 90 | 2.69E-05 | 1.53E-03 | Cadmium[a] |
| Carbon Disulfide | ND | | 459 | | ND | ND | | 459 | | ND | ND | | 459 | | ND | ND | | 0.24 | | ND | ND | Carbon Disulfide |
| Carbon Tetrachloride | ND | | 459 | | ND | ND | | 459 | | ND | 4.50E-05 | 4 | 459 | | 0.021 | ND | | 0.24 | | ND | 2.06E-02 | Carbon Tetrachloride |
| Chlorine | 0.00040 | 7 | 459 | | 0.18 | 0.0032 | 7 | 459 | | 1.47 | 3.10E-03 | 5 | 459 | | 1.42 | ND | | 0.24 | | ND | 1.47 | Chlorine |
| Chlorobenzene | ND | | 459 | | ND | ND | | 459 | | ND | 3.3E-05 | 4 | 459 | | 0.015 | ND | | 0.24 | | ND | 1.51E-02 | Chlorobenzene |
| Chloroform | ND | | 459 | | ND | ND | | 459 | | ND | 2.8E-05 | 4 | 459 | | 0.013 | ND | | 0.24 | | ND | 1.28E-02 | Chloroform |
| Chromium[a] | 2.05E-03 | 8 | 459 | 90 | 9.40E-02 | 2.05E-03 | 8 | 459 | 90 | 9.40E-02 | 5.22E-05 | 1 | 459 | 90 | 2.39E-03 | 0.0014 | 6 | 0.24 | 90 | 3.42E-05 | 9.40E-02 | Chromium[a] |
| Chromium+6 | 1.37E-04 | 9 | 459 | 90 | 6.30E-03 | 1.37E-04 | 9 | 459 | 90 | 6.30E-03 | 3.50E-06 | 4 | 459 | | 0.0016 | ND | | 0.24 | | ND | 6.30E-03 | Chromium+6 |
| Cobalt | ND | | 459 | | ND | ND | | 459 | | ND | 6.50E-06 | 4 | 459 | | 0.0030 | 8.40E-05 | 6 | 0.24 | | 2.05E-05 | 2.98E-03 | Cobalt |
| m&p-Cresol | ND | | 459 | | ND | ND | | 459 | | ND | ND | | 459 | | ND | ND | | 0.24 | | ND | ND | m&p-Cresol |
| Cumene | ND | | 459 | | ND | ND | | 459 | | ND | ND | | 459 | | ND | ND | | 0.24 | | ND | ND | Cumene |
| Dibenzofurans | ND | | 459 | | ND | ND | | 459 | | ND | 1.78E-09 | 4 | 459 | | ND | ND | | 0.24 | | ND | ND | Dibenzofurans |
| Dibutylphthalate | ND | | 459 | | ND | ND | | 459 | | ND | ND | | 459 | | ND | ND | | 0.24 | | ND | ND | Dibutylphthalate |
| 1,4-Dichlorobenzene(p) | ND | | 459 | | ND | ND | | 459 | | ND | ND | | 459 | | ND | 0.0012 | 6 | 0.24 | | 2.93E-04 | 2.93E-04 | 1,4-Dichlorobenzene(p) |
| Ethylbenzene | ND | | 459 | | ND | ND | | 459 | | ND | 3.1E-05 | 4 | 459 | | 0.014 | ND | | 0.24 | | ND | 1.42E-02 | Ethylbenzene |
| Formaldehyde | 1.50E-03 | 2 | 459 | | 0.69 | 1.50E-03 | 2 | 459 | | 0.69 | 0.0044 | 4 | 459 | | 2.02 | 0.075 | 6 | 0.24 | | 1.83E-02 | 2.02 | Formaldehyde |
| Hexane | ND | | 459 | | ND | ND | | 459 | | ND | ND | | 459 | | ND | 1.8 | 6 | 0.24 | | 4.39E-01 | 0.44 | Hexane |
| Hydrogen Chloride[b] | 9.90E-03 | 7 | 459 | 0 | 4.54 | 0.08 | 10 | 459 | 0 | 36.68 | 0.097 | 5 | 459 | 0 | 44.47 | ND | | 0.24 | 95 | ND | 44.47 | Hydrogen Chloride[b] |
| Hydrogen Fluoride | 6.00E-04 | 1 | 459 | 0 | 0.275 | 6.00E-04 | 1 | 459 | 0 | 0.275 | 6.0E-04 | 1 | 459 | 0 | 0.275 | ND | | 0.24 | | ND | 2.75E-01 | Hydrogen Fluoride |
| Lead-Total[a] | 9.60E-05 | 8 | 459 | 90 | 4.40E-03 | 9.60E-05 | 8 | 459 | 90 | 4.40E-03 | 8.4E-05 | 1 | 459 | 90 | 3.85E-03 | 5.00E-04 | 6 | 0.24 | 90 | 1.22E-05 | 4.40E-03 | Lead-Total[a] |
| Manganese[a] | 2.31E-03 | 8 | 459 | 90 | 0.11 | 2.31E-03 | 8 | 459 | 90 | 0.11 | 0.0016 | 4 | 459 | 90 | 7.34E-02 | 3.80E-04 | 6 | 0.24 | 90 | 9.28E-06 | 0.11 | Manganese[a] |
| Mercury[a] | 1.38E-05 | 8 | 459 | | 6.33E-03 | 1.38E-05 | 8 | 459 | | 6.33E-03 | 3.6E-06 | 1 | 459 | | 0.0017 | 2.60E-04 | 6 | 0.24 | | 6.35E-05 | 6.33E-03 | Mercury[a] |
| Methanol | UD | 2 | 459 | | UD | UD | 2 | 459 | | UD | ND | | 459 | | ND | ND | | 0.24 | | ND | ND | Methanol |
| Methyl Isobutyl Ketone | ND | | 459 | | ND | ND | | 459 | | ND | ND | | 459 | | ND | ND | | 0.24 | | ND | ND | Methyl Isobutyl Ketone |
| Methylene Chloride | ND | | 459 | | ND | ND | | 459 | | ND | ND | | 459 | | ND | ND | | 0.24 | | ND | ND | Methylene Chloride |
| Nickel[a] | 1.10E-03 | 8 | 459 | 90 | 5.04E-02 | 1.10E-03 | 8 | 459 | 90 | 5.04E-02 | 3.30E-05 | 4 | 459 | 90 | 1.51E-03 | 0.0021 | 6 | 0.24 | 90 | 5.13E-05 | 5.04E-02 | Nickel[a] |
| 4-Nitrophenol | ND | | 459 | | ND | ND | | 459 | | ND | 1.10E-07 | 4 | 459 | | 5.04E-05 | ND | | 0.24 | | ND | 5.04E-05 | 4-Nitrophenol |
| Pentachlorophenol (PCP) | ND | | 459 | | ND | ND | | 459 | | ND | 5.10E-08 | 4 | 459 | | 2.34E-05 | ND | | 0.24 | | ND | 2.34E-05 | Pentachlorophenol (PCP) |
| Phenols | 3.10E-05 | 2 | 459 | | 0.0142 | 3.10E-05 | 2 | 459 | | 0.0142 | 5.10E-05 | 4 | 459 | | 0.023 | ND | | 0.24 | | ND | 2.34E-02 | Phenols |
| Phosphorus | ND | | 459 | | ND | ND | | 459 | | ND | 2.70E-05 | 4 | 459 | | 0.012 | ND | | 0.24 | | ND | 1.24E-02 | Phosphorus |
| Propionaldehyde | ND | | 459 | | ND | ND | | 459 | | ND | 6.10E-05 | 4 | 459 | | 0.028 | ND | | 0.24 | | ND | 2.80E-02 | Propionaldehyde |
| Selenium[a] | 6.41E-06 | 8 | 459 | 90 | 2.94E-04 | 6.41E-06 | 8 | 459 | 90 | 2.94E-04 | 2.80E-06 | 4 | 459 | 90 | 1.28E-04 | 2.40E-05 | 6 | 0.24 | 90 | 5.86E-07 | 2.94E-04 | Selenium[a] |
| Styrene | ND | | 459 | | ND | ND | | 459 | | ND | 0.0019 | 4 | 459 | | 0.87 | ND | | 0.24 | | ND | 0.87 | Styrene |
| Dioxin/Furan (2, 3, 7, 8-Tetrachlorodibenzo-p-dioxin) | ND | | 459 | | ND | ND | | 459 | | ND | 8.60E-12 | 4 | 459 | | 3.94E-09 | ND | | 0.24 | | ND | 3.94E-09 | Dioxin/Furan (2, 3, 7, 8-Tetrachlorodibenzo-p-dioxin) |
| Toluene | 1.00E-04 | 2 | 459 | | 0.046 | 1.00E-04 | 2 | 459 | | 0.046 | 9.20E-04 | 4 | 459 | | 0.42 | 0.0034 | 6 | 0.24 | | 8.30E-04 | 0.42 | Toluene |
| 1, 1, 2-Trichloroethane | ND | | 459 | | ND | ND | | 459 | | ND | ND | | 459 | | ND | ND | | 0.24 | | ND | ND | 1, 1, 2-Trichloroethane |
| Trichloroethylene | ND | | 459 | | ND | ND | | 459 | | ND | ND | | 459 | | ND | ND | | 0.24 | | ND | ND | Trichloroethylene |
| Vinyl Chloride | ND | | 459 | | ND | ND | | 459 | | ND | 1.80E-05 | 4 | 459 | | 0.0083 | ND | | 0.24 | | ND | 8.25E-03 | Vinyl Chloride |
| m- & p-Xylene | ND | | 459 | | ND | ND | | 459 | | ND | ND | | 459 | | ND | ND | | 0.24 | | ND | ND | m- & p-Xylene |
| o-Xylene | ND | | 459 | | ND | ND | | 459 | | ND | 2.50E-05 | 4 | 459 | | 0.011 | ND | | 0.24 | | ND | 1.15E-02 | o-Xylene |

**Table 2-14: Short-Term Emissions of Hazardous Air Pollutants from the Biomass Boiler**

| | Sugarcane Bagasse | | | | | Sorghum Bagasse | | | | | Wood | | | | | Natural Gas | | | | | Maximum | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HAP | Emission Factor (lb/MMBtu) | Ref | Activity Factor (MMBtu/hr) | Control Efficiency (%) | Hourly Emissions (lb/hr) | Emission Factor (lb/MMBtu) | Ref | Activity Factor (MMBtu/hr) | Control Efficiency (%) | Hourly Emissions (lb/hr) | Emission Factor (lb/MMBtu) | Ref | Activity Factor (MMBtu/hr) | Control Efficiency (%) | Hourly Emissions (lb/hr) | Emission Factor ($lb/10^6$ scf) | Ref | Activity Factor (MMscf/hr) | Control Efficiency (%) | Hourly Emissions (lb/hr) | Emissions for All Fuels (lb/hr) | HAP |
| **POMs** | | | | | | | | | | | | | | | | | | | | | | **POMs** |
| 3-Methylcholanthrene | ND | | 459 | | ND | ND | | 459 | | ND | ND | 4 | 459 | | ND | 1.80E-06 | 7 | 0.24 | | 4.39E-07 | 4.39E-07 | 3-Methylcholanthrene |
| Acenaphthene | ND | | 459 | | ND | ND | | 459 | | ND | 9.1E-07 | 4 | 459 | | 4.17E-04 | 1.80E-06 | 7 | 0.24 | | 4.39E-07 | 4.17E-04 | Acenaphthene |
| Acenaphthylene | 1.00E-06 | 2 | 459 | | 4.59E-04 | 1.00E-06 | 2 | 459 | | 4.59E-04 | 5.0E-06 | 4 | 459 | | 0.0023 | 1.80E-06 | 7 | 0.24 | | 4.39E-07 | 2.29E-03 | Acenaphthylene |
| Anthracene | 4.56E-07 | 2 | 459 | | 2.09E-04 | 4.56E-07 | 2 | 459 | | 2.09E-04 | 3.0E-06 | 4 | 459 | | 0.0014 | 2.40E-06 | 7 | 0.24 | | 5.86E-07 | 1.38E-03 | Anthracene |
| Benzo (a) anthracene | 3.00E-06 | 2 | 459 | | 1.38E-03 | 3.00E-06 | 2 | 459 | | 1.38E-03 | 6.5E-08 | 4 | 459 | | 2.98E-05 | 1.80E-06 | 7 | 0.24 | | 4.39E-07 | 1.38E-03 | Benzo (a) anthracene |
| Benzo(a)pyrene | 1.00E-06 | 2 | 459 | | 4.59E-04 | 1.00E-06 | 2 | 459 | | 4.59E-04 | 2.6E-06 | 4 | 459 | | 0.0012 | 1.20E-06 | 7 | 0.24 | | 2.93E-07 | 1.19E-03 | Benzo(a)pyrene |
| Benzo(b)fluoranthene | 3.00E-06 | 2 | 459 | | 1.38E-03 | 3.00E-06 | 2 | 459 | | 1.38E-03 | 1.0E-07 | 4 | 459 | | 4.59E-05 | 1.80E-06 | 7 | 0.24 | | 4.39E-07 | 1.38E-03 | Benzo(b)fluoranthene |
| Benzo(e)pyrene | 1.00E-06 | 2 | 459 | | 4.59E-04 | 1.00E-06 | 2 | 459 | | 4.59E-04 | 2.6E-09 | 4 | 459 | | 1.19E-06 | ND | | 0.24 | | ND | 4.59E-04 | Benzo(e)pyrene |
| Benzo(g,h,i)perylene | ND | | 459 | | ND | ND | | 459 | | ND | 9.3E-08 | 4 | 459 | | 4.26E-05 | 1.20E-06 | 7 | 0.24 | | 2.93E-07 | 4.26E-05 | Benzo(g,h,i)perylene |
| Benzo(j,k)fluoranthene | 1.97E-06 | 2 | 459 | | 9.03E-04 | 1.97E-06 | 2 | 459 | | 9.03E-04 | 1.6E-07 | 4 | 459 | | 7.34E-05 | 1.80E-06 | 7 | 0.24 | | ND | 9.03E-04 | Benzo(j,k)fluoranthene |
| Chrysene | 3.00E-06 | 2 | 459 | | 1.38E-03 | 3.00E-06 | 2 | 459 | | 1.38E-03 | 3.8E-08 | 4 | 459 | | 1.74E-05 | 1.80E-06 | 7 | 0.24 | | 4.39E-07 | 1.38E-03 | Chrysene |
| Dibenzo(a,h)anthracene | ND | | 459 | | ND | ND | | 459 | | ND | 9.1E-09 | 4 | 459 | | 4.17E-06 | 1.20E-06 | 7 | 0.24 | | 2.93E-07 | 4.17E-06 | Dibenzo(a,h)anthracene |
| Dimethylbenz(a)anthracene | ND | | 459 | | ND | ND | | 459 | | ND | ND | 4 | 459 | | ND | ND | | 0.24 | | ND | ND | Dimethylbenz(a)anthracene |
| Fluoranthene | 1.20E-05 | 2 | 459 | | 0.0055 | 1.20E-05 | 2 | 459 | | 0.0055 | 1.6E-06 | 4 | 459 | | 7.34E-04 | 3.00E-06 | 7 | 0.24 | | 7.32E-07 | 5.50E-03 | Fluoranthene |
| Fluorene | ND | | 459 | | ND | ND | | 459 | | ND | 3.4E-06 | 4 | 459 | | 0.0016 | 2.80E-06 | 7 | 0.24 | | 6.84E-07 | 1.56E-03 | Fluorene |
| indeno(1,2,3-cd)pyrene | ND | | 459 | | ND | ND | | 459 | | ND | 8.7E-08 | 4 | 459 | | 3.99E-05 | 1.80E-06 | 7 | 0.24 | | 4.39E-07 | 3.99E-05 | indeno(1,2,3-cd)pyrene |
| Naphthalene | 2.30E-05 | 2 | 459 | | 0.0105 | 2.30E-05 | 2 | 459 | | 0.0105 | 9.7E-05 | 4 | 459 | | 0.044 | 6.10E-04 | 7 | 0.24 | | 1.49E-04 | 4.45E-02 | Naphthalene |
| Perylene | ND | | 459 | | ND | ND | | 459 | | ND | 5.2E-10 | 4 | 459 | | 2.38E-07 | ND | | 0.24 | | ND | 2.38E-07 | Perylene |
| Phenanthrene | 5.00E-06 | 2 | 459 | | 0.0023 | 5.00E-06 | 2 | 459 | | 0.0023 | 7.0E-06 | 4 | 459 | | 0.0032 | 1.70E-05 | 7 | 0.24 | | 4.15E-06 | 3.21E-03 | Phenanthrene |
| Pyrene | 1.00E-05 | 2 | 459 | | 0.0046 | 1.00E-05 | 2 | 459 | | 0.0046 | 3.7E-06 | 4 | 459 | | 0.0017 | 5.00E-06 | 7 | 0.24 | | 1.22E-06 | 4.59E-03 | Pyrene |
| Total POMs** | 6.44E-05 | | 459 | | 0.030 | 6.44E-05 | | 459 | | 0.030 | 0.00012 | | 459 | | 0.057 | 6.58E-04 | | 0.24 | | 1.61E-04 | 0.06 | Total POMs** |
| **MAXIMUM SINGLE HAP** | | | | | 4.54 | | | | | 36.68 | | | | | 44.47 | | | | | 0.439 | 44.47 | **MAXIMUM SINGLE HAP** |
| **TOTAL** | | | | | **8.65** | | | | | **42.07** | | | | | **53.92** | | | | | **0.460** | **55.27** | **TOTAL** |

UD = Undetected
ND = No Data available
[a] Assumed 90% control efficiency for all metals, except mercury for which zero control was assumed.
[b] For HCl a control efficiency of 95 percent was applied.

References
1. Based on highest stack test results for New Hope Power Company Boilers A, B, and C (1999-2002) excluding 1999 wood test for Unit C.
2. Based on HAP Emissions for U.S. Sugar-Clewiston Boiler 7 - Highest of three runs January 31, 2000.
3. Based on average of three stack testing runs of Boiler No. 7. (December, 2002)
4. Based on AP-42 emission factors for wood combustion (Section 1.6).
5. Based on the maximum of stack test result for boilers firing wood or a combination of wood and bagasse, 2004-2007. See Appendix B, Table B-4.
6. Based on AP-42 emission factors for natural gas combustion (Section 1.4).
7. Based on HAP testing of bagasse fired boilers. Maximum of 18 runs for HCl. Emissions for $Cl_2$ based on AP-42 for wood firing and Appendix B, Table B-4, which shows 4% of HCl is emitted as $Cl_2$.
8. Based on the maximum of fuel analysis results for SRF sweet sorghum analysis conducted Sept. 2009.
9. Based on the ratio of wood emission factor for Chromium VI to Chromium.
10. Based on maximum chlorine content of sorghum (0.24% Cl or 0.32 lb/MMBtu as HCl) and assuming 75% inherent removal in ash. Chlorine emissions are 4% of HCl, based on AP-42 for wood firing and Appendix B, Table B-4.
**Sum of all POMs, unless emission factors are only listed for Total POMs, not individuals, and will be noted.

**Table 2-15: Summary of Annual Emissions of Hazardous Air Pollutants from the Biomass Boiler**

| Fuel Scenario | Maximum Single HAP (TPY) | Total HAPs (TPY) |
|---|---|---|
| Bagasse Only | 6.91 | 15.84 |
| 90% Bagasse/10% Wood | 6.85 | 18.26 |
| 70% Bagasse/30% Natural Gas | 4.56 | 11.40 |
| **Worst-Case HAPs Total** | **6.91** | **18.26** |

[a] See Appendix B, Tables B-5, B-6, and B-7.

Table 2-16. Maximum Annual Fugitive Dust Emissions for Highlands EnviroFuels, LLC

| SOURCE | TYPE OF OPERATION | M MOISTURE CONTENT [a] (%) | U WIND SPEED [b] (MPH) | UNCONTROLLED PM EMISSION FACTOR (LB/TON) [c] | UNCONTROLLED $PM_{10}$ EMISSION FACTOR (LB/TON) [c] | UNCONTROLLED $PM_{2.5}$ EMISSION FACTOR (LB/TON) [c] | CONTROL TYPE | CONTROL EFFICIENCY (%) | CONTROLLED PM EMISSION FACTOR (LB/TON) | CONTROLLED $PM_{10}$ EMISSION FACTOR (LB/TON) | CONTROLLED $PM_{2.5}$ EMISSION FACTOR (LB/TON) | ACTIVITY FACTOR | MAXIMUM ANNUAL EMISSIONS PM (TSP) (TONS/YR) | $PM_{10}$ (TONS/YR) | $PM_{2.5}$ (TONS/YR) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **BIOMASS DELIVERIES** | | | | | | | | | | | | | | | |
| SUGARCANE TRUCK TRAFFIC ON PAVED ROADS[i] | VEHICULAR TRAFFIC | -- | -- | 0.11 lb/VMT | 0.022 lb/VMT | 0.0054 lb/VMT | WATER/SWEEP | 50 | 0.055 lb/VMT | 0.011 lb/VMT | 0.0027 lb/VMT | 25,500 VMT | 0.70 | 0.14 | 0.035 |
| SORGHUM TRUCK TRAFFIC ON PAVED ROADS[i] | VEHICULAR TRAFFIC | -- | -- | 0.11 lb/VMT | 0.022 lb/VMT | 0.0054 lb/VMT | WATER/SWEEP | 50 | 0.055 lb/VMT | 0.011 lb/VMT | 0.0027 lb/VMT | 25,500 VMT | 0.70 | 0.14 | 0.035 |
| WOOD TRUCK TRAFFIC ON PAVED ROADS[i] | VEHICULAR TRAFFIC | -- | -- | 0.11 lb/VMT | 0.022 lb/VMT | 0.0054 lb/VMT | WATER/SWEEP | 50 | 0.055 lb/VMT | 0.011 lb/VMT | 0.0027 lb/VMT | 1,475 VMT | 0.041 | 0.0081 | 0.0020 |
| **BAGASSE HANDLING** | | | | | | | | | | | | | | | |
| BAGASSE FROM DRYING SYSTEM-TO-TRANSFER CONVEYOR | CONTINUOUS DROP | 50 | 6.9 | 0.000040 | 0.000019 | 0.0000028 | ENCLOSURE | 0 | 0.000040 | 0.000019 | 0.0000028 | 467,874 TPY [d] | 0.0093 | 0.0044 | 0.00067 |
| TRANSFER CONVEYOR-TO-HOPPER | CONTINUOUS DROP | 50 | 6.9 | 0.000040 | 0.000019 | 0.0000028 | ENCLOSURE | 0 | 0.000040 | 0.000019 | 0.0000028 | 467,874 TPY [d] | 0.0093 | 0.0044 | 0.00067 |
| HOPPER-TO-BAGASSE DISTRIBUTION CONVEYOR | CONTINUOUS DROP | 50 | 6.9 | 0.000040 | 0.000019 | 0.0000028 | ENCLOSURE | 0 | 0.000040 | 0.000019 | 0.0000028 | 467,874 TPY [d] | 0.0093 | 0.0044 | 0.00067 |
| BAGASSE DISTRIBUTION CONVEYOR-TO-METER BINS | CONTINUOUS DROP | 50 | 6.9 | 0.000040 | 0.000019 | 0.0000028 | ENCLOSURE | 0 | 0.000040 | 0.000019 | 0.0000028 | 467,874 TPY [d] | 0.0093 | 0.0044 | 0.00067 |
| BAG. DIS. CONV. OVERFLOW-TO-SURPLUS BAGASSE CONVEYOR | CONTINUOUS DROP | 50 | 6.9 | 0.000040 | 0.000019 | 0.0000028 | ENCLOSURE | 0 | 0.000040 | 0.000019 | 0.0000028 | 46,787 TPY [e] | 0.00093 | 0.00044 | 0.000067 |
| SURPLUS BAGASSE CONVEYOR-TO-BAGASSE STORAGE PILE | CONTINUOUS DROP | 50 | 6.9 | 0.000040 | 0.000019 | 0.0000028 | ENCLOSURE | 0 | 0.000040 | 0.000019 | 0.0000028 | 46,787 TPY [e] | 0.00093 | 0.00044 | 0.000067 |
| FRONT END LOADER (RECLAIM)-TO-RECLAIM CONVEYOR | BATCH DROP | 50 | 6.9 | 0.000040 | 0.000019 | 0.0000028 | NONE | 0 | 0.000040 | 0.000019 | 0.0000028 | 46,787 TPY [e] | 0.00093 | 0.00044 | 0.000067 |
| RECLAIM CONVEYOR-TO-RETURN CONVEYOR | CONTINUOUS DROP | 50 | 6.9 | 0.000040 | 0.000019 | 0.0000028 | ENCLOSURE | 0 | 0.000040 | 0.000019 | 0.0000028 | 46,787 TPY [e] | 0.00093 | 0.00044 | 0.000067 |
| RETURN CONVEYOR-TO-BAGASSE TRANSFER CONVEYOR | CONTINUOUS DROP | 50 | 6.9 | 0.000040 | 0.000019 | 0.0000028 | ENCLOSURE | 0 | 0.000040 | 0.000019 | 0.0000028 | 46,787 TPY [e] | 0.00093 | 0.00044 | 0.000067 |
| BAGASSE TRANSFER CONVEYOR-TO-HOPPER | CONTINUOUS DROP | 50 | 6.9 | 0.000040 | 0.000019 | 0.0000028 | ENCLOSURE | 0 | 0.000040 | 0.000019 | 0.0000028 | 46,787 TPY [e] | 0.00093 | 0.00044 | 0.000067 |
| HOPPER-TO-BAGASSE DISTRIBUTION CONVEYOR | CONTINUOUS DROP | 50 | 6.9 | 0.000040 | 0.000019 | 0.0000028 | ENCLOSURE | 0 | 0.000040 | 0.000019 | 0.0000028 | 46,787 TPY [e] | 0.00093 | 0.00044 | 0.000067 |
| BAGASSE STORAGE PILE[f] | WIND EROSION | -- | -- | -- | -- | -- | WATERING | 50 | -- | -- | -- | -- | 0.015 | 0.0076 | 0.0076 |
| FRONT END LOADER BAGASSE STORAGE PILE MAINTENANCE[g] | VEHICULAR TRAFFIC | -- | -- | 0.27 lb/VMT | 0.032 lb/VMT | 0.0032 lb/VMT | PARTIAL ENCLOSURE/WATERING | 75 | 0.07 lb/VMT | 0.008 lb/VMT | 0.0008 lb/VMT | 10,950 VMT | 0.37 | 0.044 | 0.0044 |
| BULLDOZER BAGASSE STORAGE PILE MAINTENANCE[h] | VEHICULAR TRAFFIC | -- | -- | 0.031 lb/hr | 0.0018 lb/hr | 0.00067 lb/hr | PARTIAL ENCLOSURE/WATERING | 75 | 0.008 lb/hr | 0.00046 lb/hr | 0.00017 lb/hr | 2,190 hr/yr | 0.008 | 0.0005 | 0.00018 |
| **WOOD HANDLING** | | | | | | | | | | | | | | | |
| TRUCK DUMP-TO-WOOD STORAGE PILE | BATCH DROP | 40 | 6.9 | 0.000054 | 0.000026 | 0.0000039 | NONE | 0 | 0.000054 | 0.000026 | 0.0000039 | 47,705 TPY [d] | 0.0013 | 0.00061 | 0.000093 |
| UNLOADING CONVEYOR-TO-HOGGER | CONTINUOUS DROP | 40 | 6.9 | 0.000054 | 0.000026 | 0.0000039 | ENCLOSURE | 0 | 0.000054 | 0.000026 | 0.0000039 | 47,705 TPY [d] | 0.0013 | 0.00061 | 0.000093 |
| HOGGER | CRUSHING | -- | -- | 0.020 | 0.0095 | 0.0014 | ENCLOSED | 95 | 0.0010 | 0.00047 | 0.000072 | 47,705 TPY [d] | 0.024 | 0.011 | 0.0017 |
| HOGGER-TO-STORAGE CONVEYOR | BATCH DROP | 40 | 6.9 | 0.000054 | 0.000026 | 0.0000039 | ENCLOSURE | 0 | 0.000054 | 0.000026 | 0.0000039 | 47,705 TPY [d] | 0.0013 | 0.00061 | 0.000093 |
| SCREEN-TO-STORAGE CONVEYOR | CONTINUOUS DROP | 40 | 6.9 | 0.000054 | 0.000026 | 0.0000039 | ENCLOSURE | 0 | 0.000054 | 0.000026 | 0.0000039 | 47,705 TPY | 0.0013 | 0.00061 | 0.000093 |
| STORAGE CONVEYOR-TO-WOOD STORAGE PILE | CONTINUOUS DROP | 40 | 6.9 | 0.000054 | 0.000026 | 0.0000039 | ENCLOSURE | 0 | 0.000054 | 0.000026 | 0.0000039 | 47,705 TPY [e] | 0.0013 | 0.00061 | 0.000093 |
| FRONT END LOADER (RECLAIM)-TO-RECLAIM CONVEYOR | BATCH DROP | 40 | 6.9 | 0.000054 | 0.000026 | 0.0000039 | NONE | 0 | 0.000054 | 0.000026 | 0.0000039 | 47,705 TPY [d] | 0.0013 | 0.00061 | 0.000093 |
| RECLAIM CONVEYOR-TO-RETURN CONVEYOR | CONTINUOUS DROP | 40 | 6.9 | 0.000054 | 0.000026 | 0.0000039 | ENCLOSURE | 0 | 0.000054 | 0.000026 | 0.0000039 | 47,705 TPY [d] | 0.0013 | 0.00061 | 0.000093 |
| RETURN CONVEYOR-TO-HOPPER | CONTINUOUS DROP | 40 | 6.9 | 0.000054 | 0.000026 | 0.0000039 | ENCLOSURE | 0 | 0.000054 | 0.000026 | 0.0000039 | 47,705 TPY [d] | 0.0013 | 0.00061 | 0.000093 |
| HOPPER-TO-HORIZONTAL DISCHARGE CONVEYOR | CONTINUOUS DROP | 40 | 6.9 | 0.000054 | 0.000026 | 0.0000039 | ENCLOSURE | 0 | 0.000054 | 0.000026 | 0.0000039 | 47,705 TPY [d] | 0.0013 | 0.00061 | 0.000093 |
| WOOD STORAGE PILE[f] | WIND EROSION | -- | -- | -- | -- | -- | WATERING | 50 | -- | -- | -- | -- | 0.20 | 0.10 | 0.10 |
| FRONTEND LOADER WOOD STORAGE PILE MAINTENANCE[g] | VEHICULAR TRAFFIC | -- | -- | 3.52 lb/VMT | 0.86 lb/VMT | 0.086 lb/VMT | PARTIAL ENCLOSURE/WATERING | 75 | 0.88 lb/VMT | 0.21 lb/VMT | 0.021 lb/VMT | 10,950 VMT | 4.81 | 1.18 | 0.12 |
| BULLDOZER WOOD STORAGE PILE MAINTENANCE[h] | VEHICULAR TRAFFIC | -- | -- | 3.32 lb/hr | 0.61 lb/hr | 0.073 lb/hr | PARTIAL ENCLOSURE/WATERING | 75 | 0.83 lb/hr | 0.15 lb/hr | 0.018 lb/hr | 2,190 hr/yr | 0.91 | 0.17 | 0.020 |
| **ASH HANDLING** | | | | | | | | | | | | | | | |
| ASH DROP TO DRAG CONVEYOR 1 | CONTINUOUS DROP | 10 | 6.9 | 0.000378 | 0.000179 | 0.0000271 | ENCLOSURE | 0 | 0.000378 | 0.000179 | 0.0000271 | 21,634 TPY [j] | 0.0041 | 0.0019 | 0.00029 |
| DRAG CONVEYOR 1 TO DRAG CONVEYOR 2 | CONTINUOUS DROP | 10 | 6.9 | 0.000378 | 0.000179 | 0.0000271 | ENCLOSURE | 0 | 0.000376 | 0.000179 | 0.0000271 | 21,634 TPY [j] | 0.0041 | 0.0019 | 0.00029 |
| DRAG CONVEYOR 2 TO DRAG CONVEYOR 3 | CONTINUOUS DROP | 10 | 6.9 | 0.000378 | 0.000179 | 0.0000271 | ENCLOSURE | 0 | 0.000378 | 0.000179 | 0.0000271 | 21,634 TPY [j] | 0.0041 | 0.0019 | 0.00029 |
| DRAG CONVEYOR 3 TO ASH SILO | CONTINUOUS DROP | 10 | 6.9 | 0.000378 | 0.000179 | 0.0000271 | ENCLOSURE | 0 | 0.000378 | 0.000179 | 0.0000271 | 21,634 TPY [j] | 0.0041 | 0.0019 | 0.00029 |
| ASH SILO TO TRUCK | CONTINUOUS DROP | 10 | 6.9 | 0.000378 | 0.000179 | 0.0000271 | ENCLOSURE | 0 | 0.000378 | 0.000179 | 0.0000271 | 21,634 TPY [j] | 0.0041 | 0.0019 | 0.00029 |
| ASH TRUCK TRAFFIC ON PAVED ROADS[i] | VEHICULAR TRAFFIC | -- | -- | 0.11 lb/VMT | 0.022 lb/VMT | 0.0054 lb/VMT | WATER/SWEEP | 50 | 0.06 lb/VMT | 0.011 lb/VMT | 0.0027 lb/VMT | 735 VMT | 0.020 | 0.0041 | 0.0010 |
| **PRODUCT LOAD OUT** | | | | | | | | | | | | | | | |
| ETHANOL TRUCK TRAFFIC ON PAVED ROADS[i] | VEHICULAR TRAFFIC | -- | -- | 0.13 lb/VMT | 0.027 lb/VMT | 0.0065 lb/VMT | WATER/SWEEP | 50 | 0.066 lb/VMT | 0.013 lb/VMT | 0.0033 lb/VMT | 1,640 VMT | 0.055 | 0.011 | 0.0027 |
| **DENATURANT/GASOLINE DELIVERIES** | | | | | | | | | | | | | | | |
| DENATURANT/GASOLINE TRUCK TRAFFIC ON PAVED ROADS[i] | VEHICULAR TRAFFIC | -- | -- | 0.13 lb/VMT | 0.027 lb/VMT | 0.0065 lb/VMT | WATER/SWEEP | 50 | 0.066 lb/VMT | 0.013 lb/VMT | 0.0033 lb/VMT | 74 VMT | 0.0025 | 0.00049 | 0.00012 |
| **LIME DELIVERIES** | | | | | | | | | | | | | | | |
| LIME TRUCK TRAFFIC ON PAVED ROADS[i] | VEHICULAR TRAFFIC | -- | -- | 0.11 lb/VMT | 0.022 lb/VMT | 0.0054 lb/VMT | WATER/SWEEP | 50 | 0.055 lb/VMT | 0.011 lb/VMT | 0.0027 lb/VMT | 47 VMT | 0.00129 | 0.00026 | 0.000064 |
| TOTAL | | | | | | | | | | | | | 7.9 | 1.8 | 0.33 |

Notes:

[a] Bagasse will be dried to 50% moisture after it is sent through the drying system. Wood moisture content based on sample testing conducted March 2008, New Hope Power Company, LLC.

[b] Based on the average of hourly windspeed data from Fort Myers International Airport for 2001-2005.

[c] Batch Drop and Continuous Drop Emission Factors are computed from AP-42 (USEPA, 2006) Section 13.2.4: E= k x 0.0032 x (U/5)^1.3 / (M/2)^1.4 lb/ton, where k = 0.74 for PM, 0.35 for PM10, and .053 for PM2.5.

[d] Refer to Table 2-2 for biomass usage, worst-case fugitive is for the 10% wood scenario. Usage rates for bagasse (425,340 TPY) and wood (43,368 TPY), and an additional 10% was added to account for year-to-year variations.

[e] Assuming 10% of biomass is overfeed.

[f] Refer to Table C-1, Appendix C for calculation.

[g] Refer to C-2 in Appendix C.

[h] Refer to Table C-3 in Appendix C.

[i] Refer Table C-4 in Appendix C.

[j] Refer to Table C-4, Appendix C, for emissions calculation. Table 2-25 shows ash generation based on sugarcane bagasse at 1.5% ash, sorghum bagasse at 2.7% ash, wood at 9% ash.

[k] Emission factor reference: AP-42 (USEPA, 2004) Section 11.19.2. $PM_{2.5}$ assumed to be equal to $PM_{10}$.

**Table 2-17: Physical, Performance, and Emissions Data for the Cooling Tower**

| Parameter | Typical Values[a] | Basis |
|---|---|---|
| Physical Data | | |
| Number of Cells | 1 | CAD Drawing |
| Deck Dimensions (ft) | | |
| Length | 80 | CAD Drawing |
| Width | 40 | CAD Drawing |
| Height | 30 | Estimated |
| Stack Dimensions | | |
| Height (ft) | 35 | Estimated |
| Stack Top Effective Inner Diameter per cell (ft) | 33 | Estimated |
| Effective Diameter, all cells (ft) | 33.0 | Estimated |
| Performance Data | | |
| Circulating Water Flow Rate (CWFR) (gal/min) | 34,000 | Fagen |
| Design Wet Bulb Temperature (°F) | 77 | |
| Design Cold Water Temperature (°F) | | |
| Heat Rejected (MMBtu/hr) | 272.22 | Fagen |
| Design Air Flow Rate per cell (acfm) | 211,860 | |
| Hours of Operation | 8,760 | |
| Emission Data | | |
| Drift Rate[b] (DR) (percent) | 0.0010 | Fagen |
| Total Dissolved Solids (TDS) Concentration, maximum (ppm)[c] | 500 | Estimated |
| Solution Drift[d] (SD) (lb/hr) | 170 | Calculated |
| PM Drift[e] (lb/hr) | 0.0851 | |
| (TPY) | 0.373 | |
| $PM_{10}$ Drift | | |
| $PM_{10}$ Portion (percent) of PM Drift | 50 | Estimated |
| $PM_{10}$ Emissions (lb/hr) | 0.0425 | |
| (TPY) | 0.186 | |
| $PM_{2.5}$ Drift | | |
| $PM_{2.5}$ Portion (percent) of PM Drift | 50 | Estimated |
| $PM_{2.5}$ Emissions (lb/hr) | 0.0425 | |
| (TPY) | 0.186 | |

Footnotes:

[a] Typical cooling tower design for indicated conditions.

[b] Drift rate is the percent of circulating water.

[c] TDS estimated based on typical TDS value for freshwater in the vicinity of the proposed project.

[d] Includes water and based on circulating water flow rate and drift rate (CWFR x DR x 8.34 lb/gal x 60 min/hr).

[e] PM calculated based on total dissolved solids and solution drift (TDS x SD).

**Table 2-18: Physical, Performance, and Emissions Data for the Truck/Rail Loading Rack Flare**

| Parameter | | Values | Basis |
|---|---|---|---|
| Physical Data | | | |
| Dimensions (ft) | | | |
| Stack Height | | 30 | Estimated |
| Stack Diameter | | 1 | Estimated |
| Performance Data | | | |
| Hourly Ethanol/Blends Throughput ($10^3$ gallons/hr) | | 36 | 600 gpm, truck or railcar filling |
| Annual Ethanol/Blends Throughput ($10^3$ gallons/yr) | | 37,620,000 | Highlands Envirofuels, LLC |
| Flare Pilot Heat Rate (MMBtu/hr) | | 0.184 | based on 3 scfm natural gas |
| Flare Control Efficiency (%) | | 98.0 | Estimated |
| Flare Pilot Hours of Operation (hr/yr) | | 8,760 | Maximum |
| Flare Hours of Operation (hr/yr) | | 3,120 | Maximum |
| VOC Loading Emission Factor Calculation | | | |
| Saturation Factor (unitless) | | 1 | AP-42 Table 5.2-1 |
| Molecular Weight of Vapors (lb/lb-mol) | | 64 | TANKS 4.0.9d |
| Product Temperature (°R) | | 534.3 | TANKS 4.0.9d |
| True Vapor Pressure (psia) | | 8.63 | TANKS 4.0.9d (Based on gasoline RVP of 12) |
| VOC Loading Loss - Total (lb/$10^3$ gal)[a] | | 12.9 | |
| Flare Heat Input Calculation | | | |
| Gasoline Heat Content (Btu/gal) | | 130,000 | AP-42 Appendix A |
| Gasoline Density (lb/gal) | | 6.17 | AP-42 Appendix A |
| Gasoline Heat Content (Btu/lb) | | 21,070 | displaced truck gasoline vapors |
| Flare Heat Input Rate (MMBtu/hr)[b] | | 9.8 | Calculated |
| VOC Loading Emission Calculation | lb/hr | TPY | |
| Uncontrolled VOCs | 463.66 | 242.3 | |
| Controlled VOCs | 9.27 | 4.85 | |
| Flare Combustion Emission Factors | | | |
| $SO_2$ (lb/MMBtu)[c] | | 0.00059 | AP-42 Table 1.4-2 |
| NOx (lb/MMBtu)[d] | | 0.068 | AP-42 Table 13.5-1 |
| CO (lb/MMBtu)[d] | | 0.37 | AP-42 Table 13.5-1 |
| PM/$PM_{10}$/$PM_{2.5}$ (lb/MMBtu)[d] | | 0.0034 | AP-42 Table 13.5-1 |
| VOCs - Total Hydrocarbons (lb/MMBtu)[e] | | 0.14 | AP-42 Table 13.5-1 |
| Emissions Calculations | Activity Factor | Emissions | |
| | (MMBtu/hr) | (lb/hr) | (TPY) |
| $SO_2$ (lb/MMBtu) | 9.8 | 0.0057 | 0.0090 |
| NOx (lb/MMBtu) | 9.8 | 0.66 | 1.04 |
| CO (lb/MMBtu) | 9.8 | 3.61 | 5.64 |
| PM/$PM_{10}$/$PM_{2.5}$ (lb/MMBtu) | 9.8 | 0.034 | 0.052 |
| VOCs - Total Hydrocarbons (lb/MMBtu) | 9.8 | 1.37 | 2.13 |
| **Loading and Combustion Total VOCs** | -- | **10.64** | **6.98** |

[a] The emission factor for VOCs is based on the following equation for loading loss:

*VOC Loading Loss (lb/$10^3$ gal) = 12.46 x Saturation Factor x Vapor Pressure (psia) x Molecular Weight (lb/lb-mol) / Temperature (°R)*

[b] The flare heat input rate is calculated based on the following equation:

*Flare Heat Rate (MMBtu/hr) = Hourly Ethanol Throughput ($10^3$ gallons/hr) x VOC Loading Loss (lb/$10^3$ gal) x Gasoline Heat Content (Btu/lb)/$10^6$*

[c] Based on AP-42 Table 1.4-2, 0.6 lb/$10^6$ scf for Natural Gas, and 1,020 Btu/scf for natural gas.

[d] AP-42 Table 13.5-1 (Industrial Flares), soot for lightly smoking flares (40 µg/L).
Assuming all PM is converted to $PM_{10}$ and $PM_{2.5}$.

[e] Assumed all hydrocarbons are VOCs for conservative estimate.

**Table 2-19: Truck/Rail Loading Rack Flare HAP Emission Estimates**

| **Total VOC Emissions** | |
|---|---|
| Maximum Hourly (lb/hr) | 10.64 |
| Total Losses (TPY) | 6.98 |

| Speciated Constituents of Gasoline VOCs[a] | CAS Number | % of Total Vapor Released | VOC Emissions (lb/hr) | VOC Emissions (TPY) |
|---|---|---|---|---|
| **Benzene[b]** | **71-43-2** | **1.41** | **0.150** | **0.098** |
| Butane, n- | 106-97-8 | 28.53 | 3.04 | 1.99 |
| Butene, cis-2- | 590-18-1 | 0.83 | 0.0883 | 0.058 |
| Butene, trans-2- | 624-64-6 | 1.02 | 0.109 | 0.071 |
| Pentene, cis-2- | 627-20-3 | 0.67 | 0.0713 | 0.047 |
| Cyclohexane | 110-82-7 | 0.43 | 0.0458 | 0.030 |
| Cyclopentane | 287-92-3 | 0.61 | 0.0649 | 0.043 |
| Dimethylbutane, 2,2- | 75-83-2 | 1.04 | 0.111 | 0.073 |
| Dimethylpentane, 2,4- | 108-08-7 | 0.43 | 0.0458 | 0.030 |
| Ethane | 74-84-0 | 0.07 | 0.00745 | 0.0049 |
| **Ethylbenzene[b]** | **100-41-4** | **0.06** | **0.00638** | **0.0042** |
| Heptane, n- | 142-82-5 | 0.40 | 0.0426 | 0.028 |
| **Hexane, n-[b]** | **110-54-3** | **3.75** | 0.399 | 0.26 |
| Isobutane | 75-28-5 | 8.34 | 0.887 | 0.58 |
| Isopropyl Benzene | 98-82-8 | 0.01 | 0.00106 | 0.00070 |
| Methylcyclohexane | 108-87-2 | 0.12 | 0.0128 | 0.0084 |
| Methylcyclopentane | 96-37-7 | 1.41 | 0.150 | 0.098 |
| Methylheptane, 3- | 589-81-1 | 0.06 | 0.00638 | 0.0042 |
| Methylhexane, 3- | 589-34-4 | 0.42 | 0.0447 | 0.029 |
| Methylpentane, 3- | 96-14-0 | 1.99 | 0.212 | 0.139 |
| Octane, n- | 111-65-9 | 0.03 | 0.00319 | 0.0021 |
| Pentane, n- | 109-66-0 | 7.25 | 0.771 | 0.51 |
| Pentene, 1- | 109-67-1 | 0.86 | 0.0915 | 0.060 |
| Propane | 74-98-6 | 1.06 | 0.113 | 0.074 |
| **Toluene[b]** | **108-88-3** | **1.25** | **0.133** | **0.087** |
| Trans-2-Pentene | 646-04-8 | 1.37 | 0.146 | 0.096 |
| Trimethylbenzene, 1,2,4- | 95-63-6 | 0.05 | 0.00532 | 0.0035 |
| Trimethylbenzene, 1,3,5- | 108-67-8 | 0.02 | 0.00213 | 0.00140 |
| **Trimethylpentane, 2,2,4-[b]** | **540-84-1** | **0.42** | **0.0447** | **0.029** |
| Trimethylpentane, 2,3,4- | 565-75-3 | 0.07 | 0.00745 | 0.0049 |
| **Xylene, o-[b]** | **95-47-6** | **0.04** | **0.00426** | **0.0028** |
| Unidentified VOC | NA | 35.98 | 3.83 | 2.51 |
| | | **Total VOC** | 10.64 | 6.98 |
| | | **Total HAPs** | 0.34 | 0.22 |

[a] Speciation is based on EPAs SPECIATE 3.2 program for profile No. 2490.

[b] Hazardous Air Pollutant (HAP).

**Table 2-20: Physical, Performance, and Emissions Data for the Emergency Generator**

| Parameter | | Values | Basis |
|---|---|---|---|
| Performance Data | | | |
| Capacity (hp) | | 2,682 | Caterpillar |
| (ekW) | | 2,000 | Caterpillar |
| | | | |
| Fuel: No. 2 Fuel Oil or Natural Gas | | | |
| Maximum Sulfur Content (%) | | 0.0015 | On-road diesel fuel |
| Average Heat Input Rate (MMBtu/hr) | | 19.45 | Estimated |
| (gal/hr) | | 138.9 | Calculated |
| Hours of Operation (hr/yr) | | 500 | Maximum |
| | | | |
| Emission Factors | | | |
| $SO_2$ (lb/MMBtu) | | 0.00059 | for Natural Gas firing |
| NOx (g/hp-hr)[a] | | 5.39 | CAT |
| CO (g/hp-hr)[a] | | 0.29 | CAT |
| $PM/PM_{10}/PM_{2.5}$ (g/hp-hr)[a] | | 0.026 | CAT |
| VOC (g/hp-hr)[a] | | 0.11 | CAT |
| | | | |
| Emissions Calculations | | | |
| | | Emissions[b] | |
| | Activity Factor | (lb/hr) | (TPY) |
| $SO_2$ | 19.45 MMBtu/hr | 0.011 | 0.0029 |
| NOx | 2,682 hp | 31.80 | 7.95 |
| CO | 2,682 hp | 1.71 | 0.43 |
| $PM/PM_{10}/PM_{2.5}$ | 2,682 hp | 0.15 | 0.038 |
| VOC | 2,682 hp | 0.65 | 0.16 |

[a] Subpart IIII emission factors are based on a weighted cycle. Manufacturer data, based on 100% load, for Caterpillar diesel engine (CAT 3516C TA) is considered more representative. Therefore, the manufacturer emission factors were used.

[b] *Example Calculation:*

*0.29 g/hp-hr CO x 2,682 hp/generator x lb/454.6 g = 1.71 lb/hr CO*

*1.71 lb/hr CO x 500 hr/yr x 1 ton/2,000 lb = 0.43 TPY CO*

**Table 2-21: HAPs Emission Estimates for the Emergency Generator**

| Pollutant | Emission Factor (lb/MMBtu) [a] | Activity Factor (MMBtu/hr) | (MMBtu/yr) [b] | Total Emissions (lb/hr) | (TPY) |
|---|---|---|---|---|---|
| Acetaldehyde | 2.52E-05 | 19.45 | 9,725 | 4.90E-04 | 1.23E-04 |
| Acrolein | 7.88E-06 | 19.45 | 9,725 | 1.53E-04 | 3.83E-05 |
| Benzene | 7.76E-04 | 19.45 | 9,725 | 1.51E-02 | 3.77E-03 |
| Formaldehyde | 7.89E-05 | 19.45 | 9,725 | 1.53E-03 | 3.84E-04 |
| Propylene | 2.79E-03 | 19.45 | 9,725 | 5.43E-02 | 1.36E-02 |
| Naphthalene | 1.30E-04 | 19.45 | 9,725 | 2.53E-03 | 6.32E-04 |
| Toluene | 2.81E-04 | 19.45 | 9,725 | 5.47E-03 | 1.37E-03 |
| Xylene | 1.93E-04 | 19.45 | 9,725 | 3.75E-03 | 9.38E-04 |
| | | | **TOTAL HAP** | 0.083 | 0.021 |

[a] Based on information provided in EPA's AP-42, Tables 3.4-3 and 3.4-4.

[b] Based on 500 hr/yr.

**Table 2-22: Physical, Performance, and Emissions Data for the Emergency Fire Pump Engine**

| Parameter | | Values | Basis |
|---|---|---|---|
| Performance Data | | | |
| Capacity (hp) | | 600 | Caterpillar |
| (eKw) | | 448 | Caterpillar |
| Fuel: No. 2 Fuel Oil or Natural Gas | | | |
| Maximum Sulfur Content (%) | | 0.0015 | On-road diesel fuel |
| Average Heat Input Rate (MMBtu/hr) | | 4.3 | Calculated[a] |
| Hours of Operation (hr/yr) | | 500 | Maximum |
| Emission Factors | | | |
| $SO_2$ (lb/MMBtu) | | 0.00059 | for Natural Gas firing |
| NOx (g/Kw-hr)[b] | | 3.60 | Subpart IIII, Table 4 |
| CO (g/Kw-hr) | | 3.50 | Subpart IIII, Table 4 |
| $PM/PM_{10}/PM_{2.5}$ (g/Kw-hr) | | 0.20 | Subpart IIII, Table 4 |
| VOC (g/Kw-hr)[b] | | 0.40 | Subpart IIII, Table 4 |
| Emissions Calculations | | | |
| | | Emissions[c] | |
| | Activity Factor | (lb/hr) | (TPY) |
| $SO_2$ | 4.3 MMBtu/hr | 0.0025 | 0.0006 |
| NOx | 448 kW | 3.55 | 0.89 |
| CO | 448 kW | 3.45 | 0.86 |
| $PM/PM_{10}/PM_{2.5}$ | 448 kW | 0.20 | 0.049 |
| VOC | 448 kW | 0.39 | 0.10 |

[a] Based on 31.4 gal/hr diesel and 136,000 Btu/gal.

[b] Based on Subpart IIII emission limit for NOx + NMHC of 4.0 g/Kw-hr. Assuming 90% is NOx, and 10% is VOCs.

[c] *Example Calculation:*

*3.5 g/Kw-hr CO x 448 Kw x lb/454.6 g = 3.45 lb/hr CO*

*3.45 lb/hr CO x 500 hr/yr x 1 ton/2,000 lb = 0.86 TPY CO*

**Table 2-23: Fire Pump HAPs Emission Estimates**

| Pollutant | Emission Factor (lb/MMBtu) [a] | Activity Factor (MMBtu/hr) | Activity Factor (MMBtu/yr) [b] | Emissions (lb/hr) | Emissions (TPY) |
|---|---|---|---|---|---|
| Acetaldehyde | 7.67E-04 | 4.3 | 2,135 | 3.28E-03 | 8.19E-04 |
| Acenaphthylene | 1.42E-06 | 4.3 | 2,135 | 6.06E-06 | 1.52E-06 |
| Acrolein | 9.25E-05 | 4.3 | 2,135 | 3.95E-04 | 9.88E-05 |
| Anthracene | 1.87E-06 | 4.3 | 2,135 | 7.99E-06 | 2.00E-06 |
| Benzene | 9.33E-04 | 4.3 | 2,135 | 3.98E-03 | 9.96E-04 |
| Benzo(a)anthracene | 1.68E-06 | 4.3 | 2,135 | 7.17E-06 | 1.79E-06 |
| Benzo(a)pyrene | 1.88E-07 | 4.3 | 2,135 | 8.03E-07 | 2.01E-07 |
| 1,3-Butadiene | 3.91E-05 | 4.3 | 2,135 | 1.67E-04 | 4.17E-05 |
| Chrysene | 3.53E-07 | 4.3 | 2,135 | 1.51E-06 | 3.77E-07 |
| Fluoranthene | 7.61E-06 | 4.3 | 2,135 | 3.25E-05 | 8.12E-06 |
| Formaldehyde | 1.18E-03 | 4.3 | 2,135 | 5.04E-03 | 1.26E-03 |
| Indeno(1,2,3-cd)pyrene | 3.75E-07 | 4.3 | 2,135 | 1.60E-06 | 4.00E-07 |
| Phenanthrene | 2.94E-05 | 4.3 | 2,135 | 1.26E-04 | 3.14E-05 |
| Propylene | 2.58E-03 | 4.3 | 2,135 | 1.10E-02 | 2.75E-03 |
| Naphthalene | 8.48E-05 | 4.3 | 2,135 | 3.62E-04 | 9.05E-05 |
| Toluene | 4.09E-04 | 4.3 | 2,135 | 1.75E-03 | 4.37E-04 |
| Xylene | 2.85E-04 | 4.3 | 2,135 | 1.22E-03 | 3.04E-04 |
| | | | **TOTAL HAP** | 0.027 | 0.0068 |

[a] Based on information provided in EPA's AP-42, Table 3.3-2.

[b] Based on 500 hr/yr.

Table 2-24. Summary of Particulate Emissions from Silo Bagfilters

| Emission Source | Loading Rate (TPH) | Loading Rate (TPY) | Loading Time (hr/yr) | Bin Vent Filter Gas Flow Rate | Emission Rate | $PM/PM_{10}/PM_{2.5}$ Hourly Emissions (lb/hr) | $PM/PM_{10}/PM_{2.5}$ Annual Emissions (TPY) |
|---|---|---|---|---|---|---|---|
| Ash Silo | -- | -- [a] | 8,040 | 2,458 scfm | 0.01 gr/dscf | 0.21 | 0.847 |
| Lime Silo (Wastewater Treatment) | 25 | 500 | 20 | 2,458 scfm | 0.01 gr/dscf | 0.21 | 0.002 |
| Lime Silo (Dry Sorbent Injection) | 219 | 880 [a] | 4.0 | 2,458 scfm | 0.01 gr/dscf | 0.21 | 0.00042 |
| | | | | | Total Particulate Emissions = | 0.63 | 0.849 |

[a] Based on 52 lb/hr of lime to the boiler and 8,040 hr/yr for boiler operation.

Table 2-25. Estimation of Truck Traffic

| Fuel | Maximum Heat Input from Biomass [a] (MMBtu/yr) | |
|---|---|---|
| Sugarcane Bagasse | 1,843,140 | |
| Sorghum Bagasse | 1,843,140 | |
| Wood | 368,628 | |
| **TRUCK TRAFFIC** | **Activity Factor** | **Trucks/year[b]** |
| **Sugarcane[a]** | | |
| Annual Sugarcane Harvested | 750,000 TPY | 30,000 |
| **Sorghum[a]** | | |
| Annual Sorghum Harvested | 750,000 TPY | 30,000 |
| **Wood[a]** | | |
| Annual Wood Deliveries | 43,368 TPY | 1,735 |
| **Ash[c]** | | |
| Annual Ash Generation | 13,828 TPY | 553 |
| **Ethanol** | | |
| Annual Final Product | 36,000,000 Gallons/yr | 4,000 |
| **Denaturant/Gasoline Deliveries** | | |
| Annual Denaturant/Gasoline | 1,620,000 Gallons/yr | 180 |
| **Lime[d]** | | |
| Annual Lime Deliveries | 1,380 TPY | 55 |

[a] Refer to Table 2-2.

[b] Based on 25 tons per truck load capacity or 9,000 gallons per truck.

[c] Total future ash is based on 9% ash in wood, 1.5% ash in sugarcane bagasse, and 2.7% ash in sorghum bagasse. Worst case is therefore burning 30% wood with remainder bagasse.

[d] Total includes dry sorbent injection reagent and wastewater treatment lime (see Table 2-24).

Table 2-26: VOC Emission Estimates for Fugitive Equipment Leaks, HEF Ethanol Process

| Component Type | Service | Component Count | Emission Factors (kg/hr/source)[a] | Weighted Average VOC Content (%)[b] | Uncontrolled Emissions[d] (lb/hr) | Uncontrolled Emissions[d] (TPY) | Control Efficiency (%)[c] | Controlled Emissions[d] (lb/hr) | Controlled Emissions[d] (TPY) |
|---|---|---|---|---|---|---|---|---|---|
| Valves | Gas/Vapor | 25 | 0.00597 | 100 | 0.33 | 1.44 | 87 | 0.043 | 0.187 |
| Valves | Light Liquid | 200 | 0.00403 | 96 | 1.70 | 7.46 | 84 | 0.272 | 1.193 |
| Valves | Heavy Liquid | 100 | 0.00023 | 5 | 0.0025 | 0.0111 | 0 | 0.0025 | 0.0111 |
| Sealless Valves | Light Liquid | 200 | 4.90E-07 | 96 | 0.00021 | 0.00091 | 84 | 0.00003 | 0.00015 |
| Sealless Valves | Heavy Liquid | 100 | 0 | 5 | 0 | 0 | 0 | 0 | 0 |
| Pump Seals | Light Liquid | 0 | 0.0199 | 96 | 0 | 0 | 69 | 0 | 0 |
| Pump Seals | Heavy Liquid | 0 | 0.00862 | 5 | 0 | 0 | 0 | 0 | 0 |
| Pump Seals, Dual Mech. | Light Liquid | 50 | 0.0199 | 96 | 2.101 | 9.204 | 69 | 0.651 | 2.853 |
| Pump Seals, Dual Mech. | Heavy Liquid | 10 | 0.00862 | 5 | 0 | 0 | 0 | 0 | 0 |
| Agitator Seals | Light Liquid | 10 | 0.0199 | 96 | 0.42 | 1.84 | 69 | 0.13 | 0.57 |
| Agitator Seals | Heavy Liquid | 10 | 0.00862 | 5 | 0.0095 | 0.0415 | 0 | 0.009 | 0.042 |
| Compressor Seals | Gas/Vapor | 0 | 0.228 | 100 | 0 | 0 | 0 | 0 | 0 |
| Pressure Relief Valves | Gas/Vapor | 0 | 0.104 | 100 | 0 | 0 | 0 | 0 | 0 |
| Connectors | All | 1250 | 0.00183 | 30 | 1.51 | 6.61 | 93 | 0.11 | 0.46 |
| Open-Ended Lines | All | 60 | 0.0017 | 30 | 0.067 | 0.295 | 0 | 0.067 | 0.295 |
| Sampling Connections | All | 20 | 0.015 | 30 | 0.20 | 0.87 | 0 | 0.198 | 0.867 |
| | | | | | **6.35** | **27.81** | **Total VOCs** | **1.49** | **6.52** |
| | | | | | | | **Total HAPs[e]** | **0.074** | **0.33** |

[a] Emission factors are based on *Protocol for Equipment Leak Emission Estimates*, EPA-453/R-95-017, November 1995. Table 2-1 for SOCMI Average Emission Factors, or Table 2-11 for Default-Zero Values.

[b] For components in heavy liquid service, weighted average VOC content estimated at 5 perecent.
For components in light liquid service, weighted average VOC content estimated at 96 percent.
For components in liquid service, weighted average VOC content estimated at 30 perecent.

[c] Control Efficiency for LDAR program for each component is based on Table 5-2 of *Protocol for Equipment Leak Emission Estimates*, EPA-453/R-95-017, November 1995.

[d] Emissions were calculated assuming 8,760 hours of operation. Example Calculations are shown below:

Uncontrolled for Gas/Vapor Valve:

Short term emissions - 25 sources x 0.00597 kg/hr/source x 2.2 lb/kg x (% VOC content / 100)= 0.33 lb/hr
Annual - 0.33 lb/hr x 8,760 hr/yr / 2,000 lb/ton = 1.44 TPY

Controlled for Gas/Vapor Valve:

Short term emissions - 0.33 lb/hr x (1-(87/100)) = 0.043 lb/hr
Annual - 0.043 lb/hr x 8,760 hr/yr / 2,000 lb/ton = 0.19 TPY

[e] HAP emissions are conservatively estimated to be 5% of VOC emissions.

**Table 2-27: Emission Summary, Highlands EnviroFuels**

| Source Description | Pollutant Emission Rate (TPY) | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | $SO_2$ | $NO_x$ | CO | PM | $PM_{10}$ | $PM_{2.5}$ | VOC | TRS | SAM | Mercury | Lead | Fluoride | Non-Biogenic $CO_2e$[b] |
| **Future Potential Emissions From Affected Sources [a]** | | | | | | | | | | | | | |
| Biomass Boiler | 200.4 | 184.3 | 552.9 | 27.6 | 27.6 | 18.0 | 31.3 | -- | 9.8 | 0.025 | 0.18 | 1.1 | 8,023.0 |
| Boiler Materials Handling, Storage, and Truck Traffic | -- | -- | -- | 14.2 | 3.4 | 0.7 | -- | -- | -- | -- | -- | -- | -- |
| Ethanol Process | -- | -- | -- | -- | -- | -- | 79.5 | -- | -- | -- | -- | -- | -- |
| Cooling Tower | -- | -- | -- | 0.37 | 0.19 | 0.19 | -- | -- | -- | -- | -- | -- | -- |
| Truck Load Out Flare | 0.0090 | 1.04 | 5.64 | 0.052 | 0.052 | 0.052 | 2.13 | -- | -- | -- | -- | -- | 2,429.0 |
| Facility Tanks | -- | -- | -- | -- | -- | -- | 3.9 | -- | -- | -- | -- | -- | -- |
| Facility Fugitive Equipment Leaks | -- | -- | -- | -- | -- | -- | 6.5 | -- | -- | -- | -- | -- | -- |
| Emergency Generator | 0.0057 | 7.95 | 0.43 | 0.038 | 0.038 | 0.038 | 0.16 | -- | -- | -- | -- | -- | -- |
| Emergency Fire Pump Engine | 0.00063 | 0.89 | 0.86 | 0.049 | 0.049 | 0.049 | 0.10 | -- | -- | -- | -- | -- | -- |
| Ash and Lime/Limestone Silos | -- | -- | -- | 0.85 | 0.85 | 0.85 | -- | -- | -- | -- | -- | -- | -- |
| **TOTAL PROPOSED PROJECT EMISSIONS** | **200.4** | **194.2** | **559.8** | **43.2** | **32.2** | **19.8** | **123.6** | **--** | **9.8** | **0.0** | **0.2** | **1.1** | **10,452.0** |

[a] Refer to Tables 2-4 through 2-29, Appendix C and Appendix D for emission calculations.

[b] Greenhouse gases expressed as non-biogenic $CO_2$ equivalents, see Table 2-28.

**Table 2-28: Total Facility Potential HAPs Emissions**

| Source Description | HAP Emission Rate[a] (lb/hr) | HAP Emission Rate[a] (TPY) |
|---|---|---|
| Biomass Boiler | 55.3 | 18.3 |
| Ethanol Process | 1.05 | 3.85 |
| Truck Load Out Flare | 0.34 | 0.22 |
| Facility Tanks | 0.024 | 0.094 |
| Facility Fugitive Equipment Leaks | 0.074 | 0.33 |
| Emergency Generator | 0.083 | 0.021 |
| Emergency Fire Pump Engine | 0.027 | 0.0068 |
| **TOTAL** | **56.9** | **22.8** |

[a] Refer to Tables 2-4 through 2-29, Appendix C, and Appendix D for emission calculations.

**Table 2-29. Potential Direct GHG Emissions, Highlands EnviroFuels**

| | | | | | Potential Annual GHG Emissions | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | $CO_2$ | | $N_2O$ | | | $CH_4$ | | | | |
| | Allowable | Fuel Heating value | Operation | Fuel Use | Factor | Emissions | Factor | Emissions | | Factor | Emissions | | Total $CO_2$ Equivalent | Non-Biogenic $CO_2$ Equivalent[h] |
| E.U. | Fuels | | (hrs) | | (kg/MMBtu)[a] | (tons) | (kg/MMBtu)[a] | (tons) | $CO_2e$ tons [b] | (kg/MMBtu)[a] | (tons) | $CO_2e$ tons [c] | (tons) | (tons) |
| **Biomass Boiler** | | | | | | | | | | | | | | |
| Bagasse Only Scenario | Sugarcane Bagasse | 3,900 Btu/lb, wet | 4,020 | 236,300 TPY, wet | NA | 199,280 [d] | 4.20E-03 | 8.53 | 2,646 [e] | 3.20E-02 | 65.0 | 1,366 [e] | 203,291 | 4,011 |
| | Sorghum Bagasse | 3,900 Btu/lb, wet | 4,020 | 236,300 TPY, wet | NA | 199,280 [d] | 4.20E-03 | 8.53 | 2,646 [e] | 3.20E-02 | 65.0 | 1,366 [e] | 203,291 | 4,011 |
| | | | | | Subtotal | 398,559 | | 17.1 | 5,291 | | 130.1 | 2,731 | 406,582 | 8,023 |
| 10% Wood Scenario | Sugarcane Bagasse | 3,900 Btu/lb, wet | 2,814 | 212,670 TPY, wet | NA | 179,352 [d] | 4.20E-03 | 7.68 | 2,381 [e] | 3.20E-02 | 58.5 | 1,229 [e] | 182,962 | 3,610 |
| | Sorghum Bagasse | 3,900 Btu/lb, wet | 2,814 | 212,670 TPY, wet | NA | 179,352 [d] | 4.20E-03 | 7.68 | 2,381 [e] | 3.20E-02 | 58.5 | 1,229 [e] | 182,962 | 3,610 |
| | Wood | 4,250 Btu/lb, wet | 2,412 | 43,368 TPY, wet | 93.80 | 36,574 [d] | 4.20E-03 | 1.71 | 529 [e] | 3.20E-02 | 13.0 | 273 [e] | 37,376 | 802 |
| | | | | | Subtotal | 395,277 | | 17.1 | 5,291 | | 130.1 | 2,731 | 403,300 | 8,023 |
| 30% Natural Gas Scenario | Sugarcane Bagasse | 3,900 Btu/lb, wet | 2,814 | 155,788 TPY, wet | NA | 131,381 [d] | 4.20E-03 | 5.63 | 1,744 [e] | 3.20E-02 | 42.9 | 900 [e] | 134,026 | 2,645 |
| | Sorghum Bagasse | 3,900 Btu/lb, wet | 2,814 | 155,788 TPY, wet | NA | 131,381 [d] | 4.20E-03 | 5.63 | 1,744 [e] | 3.20E-02 | 42.9 | 900 [e] | 134,026 | 2,645 |
| | Natural Gas | 0.00102 MMBtu/scf | 2,412 | 1,021 MMscf/yr | 66.83 | 76,558 [f] | 1.00E-04 | 0.11 | 36 [f] | 1.00E-03 | 1.15 | 24 [f] | 76,617 | 60 |
| | | | | | Subtotal | 339,320 | | 11.4 | 3,524 | | 86.9 | 1,825 | 344,669 | 5,349 |
| | | | | | **Worst-Case Subtotal Boiler =** | **398,559** | | **17.1** | **5,291** | | **130.1** | **2,731** | **406,582** | **8,023** |
| **Flares** | | | | | | | | | | | | | | |
| Truck Loadout - flaring | Ethanol/Gasoline | 0.130 MMBtu/gal | 3,120 | 9.8 MMBtu/hr | 68.44 | 2,302 [f] | 6.00E-04 | 0.020 | 6.3 [f] | 3.00E-03 | 0.10 | 2.1 [f] | 2,310 | 2,310 |
| Truck Loadout - pilot | Natural Gas | 0.00102 MMBtu/scf | 8,760 | 0.184 MMBtu/hr | 66.83 | 118 [f] | 1.00E-04 | 0.00018 | 0.1 [f] | 1.00E-03 | 0.0018 | 0.04 [f] | 119 | 119 |
| | | | | | **Subtotal Flares =** | 2,420 | | 0.020 | 6.3 | | 0.10 | 2.2 | 2,429 | 2,429 |
| | | | | | $CO_2$ [g] | | | | | | | | | |
| **Ethanol Process $CO_2$ Scrubbing Columns** | | | | | lb/hr | tons | | | | | | | | |
| Fermentation | Vapors | -- | 7,296 | | 33,469 | 122,096 | NA | NA | NA | NA | NA | NA | 122,096 | 0 |
| Distillation | Vapors | -- | 7,296 | | 790 | 2,880 | NA | NA | NA | NA | NA | NA | 2,880 | 0 |
| | | | | | **Subtotal Ethanol Process =** | 124,976 | | | | | | | 124,976 | 0 |
| | | | | | **Totals** | **525,956** | | **17** | **5,298** | | **130** | **2,733** | **533,987** | **10,451** |

Note: tonnes = metric tons.

[a] Emission factors based on default values found in tables C-1 and C-2 of 40 CFR 98 Subpart C.

[b] $N_2O$ is multiplied by a factor of 310 to determine $CO_2$ equivalence.

[c] $CH_4$ is multiplied by a factor of 21 to determine $CO_2$ equivalence.

[d] $CO_2$ emissions from biomass based on fuel carbon content and annual fuel usage to estimate $CO_2$ emissions (Equation C-3 of 40 CFR 98 Subpart C).

Biomass: $CO_2$ (tons) = (44/12) x Fuel Use (short tons) x Carbon Content (percent by weight, expressed as a decimal fraction) x 0.91.

Carbon content of 23.0 % (at 50% moisture) for bagasse.

[e] Emissions based on fuel use, site specific fuel heat content, and default emission factor. Example calculation:

Emissions (tons) = Fuel Use (short tons) x HHV (average of fuel high heat value) x EF (Default emission factor for $CH_4$ or $N_2O$ from 40 CFR 98, Table C-2) x 0.001 (tonnes/kg) x (2205 lb/tonne / 2000 lb/ton).

[f] Emissions based on: fuel use x emission factor x hours of operation.

[g] $CO_2$ emissions based on design data.

[h] $CO_2$ emissions are excluded from biomass combustion.

**Table 2-30: Stack Parameters for Project Sources**

| | Physical Data | | | | Operating Data | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Height | | Diameter | | Temperature | | Flow Rate | Velocity | |
| **Project Source** | (ft) | (m) | (ft) | (m) | (°F) | (K) | (acfm) | (ft/s) | (m/s) |
| Biomass Boiler | 150 | 45.72 | 14 | 4.3 | 340 | 444 | 204,080 | 22.1 | 6.7 |
| Cooling Tower 1 - Machine | 35 | 10.7 | 33 | 10.1 | 77 | 298 | 211,860 | 4.1 | 1.3 |
| Truck Load Out Flare | 30 | 9.1 | 1.0 | 0.3 | 1,832 | 1,273 [a] | -- | 5.2 | 1.6 |
| Ash Silo | 35 | 10.7 | 1.5 | 0.5 | 77 | 298 | -- | 23.6 | 7.2 |
| Lime Silo 1 | 35 | 10.7 | 1.5 | 0.5 | 77 | 298 | -- | 23.6 | 7.2 |
| Lime Silo 2 | 35 | 10.7 | 1.5 | 0.5 | 77 | 298 | -- | 23.6 | 7.2 |
| $CO_2$ Scrubber | -- | -- | -- | -- | -- | -- | 4,566 | -- | -- |
| Distillation Vent Scrubber | -- | -- | -- | -- | -- | -- | 120 | -- | -- |

[a] Default temperature used in AERMOD for flare modeling.

**TABLE 3-1**
**NATIONAL AND STATE AAQS, ALLOWABLE PSD INCREMENTS, AND SIGNIFICANT IMPACT LEVELS (µg/m$^3$)**

| Pollutant | Averaging Time | National AAQS Primary Standard | National AAQS Secondary Standard | Florida AAQS[a] | PSD Increments[a] Class I | PSD Increments[a] Class II | Significant Impact Levels[b] Class I | Significant Impact Levels[b] Class II |
|---|---|---|---|---|---|---|---|---|
| Particulate Matter[c] | | | | | | | | |
| $PM_{10}$ | Annual Arithmetic Mean | 50 | 50 | 50 | 4 | 17 | 0.2 | 1 |
| | 24-Hour Maximum | 150 | 150 | 150 | 8 | 30 | 0.3 | 5 |
| $PM_{2.5}$ | Annual Arithmetic Mean | 15 | 15 | NA | NA | 4 | 0.06 | 0.3 |
| | 24-Hour Maximum | 35 | 35 | NA | NA | 9 | 0.07 | 1.2 |
| Sulfur Dioxide | Annual Arithmetic Mean | NA | NA | 60 | 2 | 20 | 0.1 | 1 |
| | 24-Hour Maximum | NA | NA | 260 | 5 | 91 | 0.2 | 5 |
| | 3-Hour Maximum | NA | 1,300 | 1,300 | 25 | 512 | 1.0 | 25 |
| | 1-Hour Maximum[d] | 196 | NA | NA | NA | NA | NA | 7.9[h] |
| Carbon Monoxide | 8-Hour Maximum | 10,000 | 10,000 | 10,000 | NA | NA | NA | 500 |
| | 1-Hour Maximum | 40,000 | 40,000 | 40,000 | NA | NA | NA | 2,000 |
| Nitrogen Dioxide | Annual Arithmetic Mean | 100 | 100 | 100 | 2.5 | 25 | 0.1 | 1 |
| | 1-Hour Maximum[e] | 188 | NA | NA | NA | NA | NA | 7.6[h] |
| Ozone | 1-Hour Maximum[f] | 235 | 235 | 235 | NA | NA | NA | NA |
| | 8-Hour Maximum[g] | 147 | 147 | NA | NA | NA | NA | NA |
| Lead | Calendar Quarter Arithmetic Mean | 1.5 | 1.5 | 1.5 | NA | NA | NA | NA |
| | 3-Month Average | 0.15 | 0.15 | NA | NA | NA | NA | NA |

Note: NA = Not applicable, i.e., no standard exists.
Particulate matter ($PM_{10}$) = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.
Particulate matter ($PM_{2.5}$) = particulate matter with aerodynamic diameter less than or equal to 2.5 micrometers.

[a] Short-term maximum concentrations are not to be exceeded more than once per year, except for $PM_{10}$ and $O_3$ AAQS, which are based on expected exceedances.
[b] Maximum concentrations are not to be exceeded.
[c] On October 17, 2006, EPA promulgated revised $PM_{10}$ and $PM_{2.5}$ AAQS. The $PM_{2.5}$ AAQS had been promulgated on July 18, 1997. For $PM_{10}$, the annual standard was revoked and the 24-hour standard was retained. The 24-hour $PM_{2.5}$ standard was revised to 35 µg/m$^3$ based on the 3-year averages of the 98th percentile values. The annual $PM_{2.5}$ standard of 15 µg/m$^3$, based on 3-year averages at community monitors, was retained. FDEP has not yet adopted the revised standards, which must be implemented in the 2009-2010 timeframe.
[d] The 1-hour $SO_2$ standard is met when the 3-year average of the 99th percentile of the daily 1-hour maximum values is less than 196 µg/m$^3$.
[e] The 1-hour $NO_2$ standard is met when the 3-year average of the 98th percentile of the daily 1-hour maximum values is less than 188 µg/m$^3$.
[f] On March 27, 2008, EPA promulgated revised AAQS for ozone. The $O_3$ standard was modified to be 0.075 ppm (147 µg/m$^3$) for the 8-hour average; achieved when the 3-year average of 99th percentile values is 0.075 ppm or less. FDEP has not yet adopted the revised standards.
[g] 0.12 ppm; achieved when the expected number of days per year with concentrations above the standard is fewer than 1.
[h] For $NO_2$ and $SO_2$ 1-hour averaging periods, an interim Class II significant impact level is shown.

Sources: 40 CFR 50; 40 CFR 52.21, Florida Chapter 62.204, F.A.C.

Table 3-3: PSD Applicability Analysis

| Source Description | Pollutant Emission Rate (TPY) | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | $SO_2$ | $NO_x$ | CO | PM | $PM_{10}$ | $PM_{2.5}$ | VOC | TRS | SAM | Mercury | Lead | Fluoride | Non-Biogenic $CO_2e$ [b] |
| **Future Potential Emissions From Affected Sources** [a] | | | | | | | | | | | | | |
| Biomass Boiler | 200.4 | 184.3 | 552.9 | 27.6 | 27.6 | 18.0 | 31.3 | -- | 9.8 | 0.025 | 0.18 | 1.1 | 8,023.0 |
| Boiler Materials Handling, Storage, and Truck Traffic | -- | -- | -- | 7.9 | 1.8 | 0.3 | -- | -- | -- | -- | -- | -- | -- |
| Ethanol Process | -- | -- | -- | -- | -- | -- | 79.5 | -- | -- | -- | -- | -- | -- |
| Cooling Tower | -- | -- | -- | 0.37 | 0.19 | 0.19 | -- | -- | -- | -- | -- | -- | -- |
| Truck Load Out Flare | 0.0090 | 1.04 | 5.64 | 0.052 | 0.052 | 0.052 | 2.13 | -- | -- | -- | -- | -- | 2,429.0 |
| Facility Tanks | -- | -- | -- | -- | -- | -- | 3.9 | -- | -- | -- | -- | -- | -- |
| Facility Fugitive Equipment Leaks | -- | -- | -- | -- | -- | -- | 6.5 | -- | -- | -- | -- | -- | -- |
| Emergency Generator | 0.0057 | 7.95 | 0.43 | 0.038 | 0.038 | 0.038 | 0.16 | -- | -- | -- | -- | -- | -- |
| Emergency Fire Pump Engine | 0.00063 | 0.89 | 0.86 | 0.049 | 0.049 | 0.049 | 0.10 | -- | -- | -- | -- | -- | -- |
| Ash and Lime/Limestone Silos | -- | -- | -- | 0.85 | 0.85 | 0.85 | -- | -- | -- | -- | -- | -- | -- |
| *Total Potential Emission Rates* | | | | | | | | | | | | | |
| **TOTAL CHANGE DUE TO PROPOSED PROJECT** | **200.4** | **194.2** | **559.8** | **36.9** | **30.6** | **19.5** | **123.6** | **0.0** | **9.8** | **0.025** | **0.2** | **1.1** | **10,452.0** |
| **PSD SIGNIFICANT EMISSION RATE** | 40 | 40 | 100 | 25 | 15 | 10 | 40 | 10 | 7 | 0.10 | 0.6 | 3 | 100,000 |
| **PSD REVIEW TRIGGERED?** | Yes | Yes | Yes | Yes | Yes | Yes | Yes | No | Yes | No | No | No | No |

[a] Refer to Table 2-27.

[b] Greenhouse gases expressed as non-biogenic $CO_2$ equivalents, see Table 2-29.

**Table 3-3: PSD Applicability Analysis**

| Source Description | Pollutant Emission Rate (TPY) | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | $SO_2$ | $NO_x$ | CO | PM | $PM_{10}$ | $PM_{2.5}$ | VOC | TRS | SAM | Mercury | Lead | Fluoride | Non-Biogenic $CO_2e$[b] |
| **Future Potential Emissions From Affected Sources** [a] | | | | | | | | | | | | | |
| Biomass Boiler | 200.4 | 184.3 | 552.9 | 27.6 | 27.6 | 18.0 | 31.3 | -- | 9.8 | 0.025 | 0.18 | 1.1 | 8,023.0 |
| Boiler Materials Handling, Storage, and Truck Traffic | -- | -- | -- | 7.9 | 1.8 | 0.3 | -- | -- | -- | -- | -- | -- | -- |
| Ethanol Process | -- | -- | -- | -- | -- | -- | 79.5 | -- | -- | -- | -- | -- | -- |
| Cooling Tower | -- | -- | -- | 0.37 | 0.19 | 0.19 | -- | -- | -- | -- | -- | -- | -- |
| Truck Load Out Flare | 0.0090 | 1.04 | 5.64 | 0.052 | 0.052 | 0.052 | 2.13 | -- | -- | -- | -- | -- | 2,429.0 |
| Facility Tanks | -- | -- | -- | -- | -- | -- | 3.9 | -- | -- | -- | -- | -- | -- |
| Facility Fugitive Equipment Leaks | -- | -- | -- | -- | -- | -- | 6.5 | -- | -- | -- | -- | -- | -- |
| Emergency Generator | 0.0057 | 7.95 | 0.43 | 0.038 | 0.038 | 0.038 | 0.16 | -- | -- | -- | -- | -- | -- |
| Emergency Fire Pump Engine | 0.00063 | 0.89 | 0.86 | 0.049 | 0.049 | 0.049 | 0.10 | -- | -- | -- | -- | -- | -- |
| Ash and Lime/Limestone Silos | -- | -- | -- | 0.85 | 0.85 | 0.85 | -- | -- | -- | -- | -- | -- | -- |
| *Total Potential Emission Rates* | | | | | | | | | | | | | |
| **TOTAL CHANGE DUE TO PROPOSED PROJECT** | **200.4** | **194.2** | **559.8** | **36.9** | **30.6** | **19.5** | **123.6** | **0.0** | **9.8** | **0.0** | **0.2** | **1.1** | **10,452.0** |
| **PSD SIGNIFICANT EMISSION RATE** | 40 | 40 | 100 | 25 | 15 | 10 | 40 | 10 | 7 | 0.1 | 0.6 | 3 | 100,000 |
| **PSD REVIEW TRIGGERED?** | Yes | Yes | Yes | Yes | Yes | Yes | Yes | No | Yes | No | No | No | No |

[a] Refer to Table 2-30.

[b] Greenhouse gases expressed as non-biogenic $CO_2$ equivalents, see Table 2-28.

**Table 4-1**
**Maximum Predicted Impacts for HEF Project Only**
**Compared to EPA *De Minimis* Concentration Levels**

| Pollutant | Averaging Time | Maximum Concentration ($\mu g/m^3$) | *De Minimis* Concentration ($\mu g/m^3$) |
|---|---|---|---|
| $SO_2$ | 24-Hour | 8.1 | 13 |
| $NO_2$ | Annual | 0.6 | 14 |
| CO | 8-Hour | 297.0 | 575 |
| $PM_{2.5}$ | 24-Hour | 23.4 | 4 |
| $PM_{10}$ | 24-Hour | 33.7 | 10 |
| $O_3$ | NA | 123.6[a] | 100[a] |

[a] Values shown are for VOCs, in TPY. No *de minimis* concentration for ozone. An increase in emissions of 100 TPY or more requires a monitoring analysis for ozone.

**Table 4-2: Summary of Measured $PM_{10}$/$PM_{2.5}$ Concentrations for Monitors near HEF, 2008 to 2010**

| | | | | | Concentration (µg/m³) | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Distance to HEF | Measurement Period | | 24-Hour | | | | Annual |
| Site No. | Location | (km) | Year | Months | Highest | 2nd Highest | 98th Percentile | 3 Year Avg. 98th Percentile | Average |
| $PM_{10}$ [a] | Florida AAQS: | | | | NA | 150 µg/m³ | NA | NA | 50 µg/m³ |
| 12-115-1006 | Sarasota | 114 | 2008 | Jan-Dec | 74 | 60 | NA | NA | 20.0 |
| | | | 2009 | Jan-Dec | 40 | 39 | NA | NA | 18.4 |
| | | | 2010 | Jan-Dec | 64 | 59 | NA | NA | 18.8 |
| 12-115-2006 | Mulberry | 97 | 2008 | Jan-Dec | 65 | 52 | NA | NA | 19.0 |
| | | | 2009 | Jan-Dec | 44 | 41 | NA | NA | 17.8 |
| | | | 2010 | Jan-Dec | 62 | 47 | NA | NA | 16.0 |
| $PM_{2.5}$ [a] | Florida AAQS: | | | | NA | NA | NA | 35 µg/m³ | 15 µg/m³ |
| 12-099-0008 | Belle Glade | 86 | 2008 | Jan-Dec | 29.1 | 19.0 | 17.1 | 18.0 | 6.53 |
| | | | 2009 | Jan-Dec | 19.9 | 18.6 | 13.8 | 16.4 | 6.05 |
| | | | 2010 | Jan-Dec | 15.0 | 13.9 | 12.0 | 14.7 | 6.35 |
| 12-057-3002 | Plant City | 121 | 2008 | Jan-Dec | 20.2 | 19.0 | 16.1 | 20.9 | 8.58 |
| | | | 2009 | Jan-Dec | 20.4 | 19.6 | 17.2 | 20.2 | 7.62 |
| | | | 2010 | Jan-Dec | 18.3 | 15.8 | 14.6 | 16.2 | 8.14 |
| 12-105-6006 | Lakeland | 111 | 2008 | Jan-Dec | 19.4 | 17.2 | 17.6 | 18.1 | 8.66 |
| | | | 2009 | Jan-Dec | 20.2 | 13.4 | 13.4 | 16.5 | 7.24 |
| | | | 2010 | Jan-Dec | 15.7 | 15.5 | 15.3 | 15.3 | 7.71 |
| 12-071-0005 | Fort Myers Beach | 85 | 2008 | Jan-Dec | 20.2 | 16.2 | 16.2 | 17.4 | 7.44 |
| | | | 2009 | Jan-Dec | 17.2 | 15.7 | 13.0 | 14.6 | 6.52 |
| | | | 2010 | Jan-Dec | 21.5 | 14.0 | 12.8 | 12.9 | 6.97 |

Note: NA = not applicable.
AAQS = ambient air quality standard.

[a] On October 17, 2006, EPA promulgated revised $PM_{10}$ and $PM_{2.5}$ AAQS. The $PM_{2.5}$ AAQS had been promulgated on July 18, 1997. For $PM_{10}$, the annual standard was revoked and the 24-hour standard was retained. The 24-hour $PM_{2.5}$ standard was revised to 35 µg/m³ based on the 3-year averages of the 98th percentile values. The annual $PM_{2.5}$ standard of 15 µg/m³, based on 3-year averages at community monitors, was retained. FDEP has not yet adopted the revised standards.

Source: State of Florida Air Quality Quicklook Reports 2008-2010.

Table 4-3: Summary of Maximum Measured $SO_2$ Concentrations near HEF, 2008 to 2010

| Site No. | Location | Distance to HEF (km) | Measurement Period Year | Measurement Period Months | 1-Hour Highest | 1-Hour 2nd Highest | 1-Hour 99th Percentile | 1-Hour 3 Year Avg. 99th Percentile | 3-Hour Highest | 3-Hour 2nd Highest | 24-Hour Highest | 24-Hour 2nd Highest | Annual Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Concentration (µg/m³) | | | | | | | | |
| **Sulfur Dioxide** | **Florida AAQS:** | | | | **NA** | **NA** | **NA** | **196.5** | **NA** | **1,300** | **NA** | **365** | **60** |
| 12-095-2002 | Winter Park | 154 | 2008 | Jan-Dec | 31.4 | 26.2 | -- | -- | 23.5 | 18.3 | 5.2 | 5.2 | 2.6 |
| | | | 2009 | Jan-Dec | 28.8 | 26.2 | -- | -- | 23.5 | 15.7 | 7.8 | 5.2 | 2.6 |
| | | | 2010 | Jan-Dec | 26.2 | 23.5 | 18.3 | 18.3 | -- | -- | 8.4 | 5.8 | 0.4 |
| 12-057-3002 | Plant City | 121 | 2008 | Jan-Dec | 143.8 | 73.2 | -- | -- | 52.3 | 39.2 | 13.1 | 10.5 | 2.6 |
| | | | 2009 | Jan-Dec | 47.1 | 44.5 | -- | -- | 26.2 | 26.2 | 10.5 | 7.8 | 1.6 |
| | | | 2010 | Jan-Dec | 70.6 | 44.5 | 39.2 | 39.2 | -- | -- | 9.4 | 8.6 | 1.8 |

Note: NA = not applicable.
AAQS = ambient air quality standard.

Source: State of Florida Air Quality Quicklook Reports 2008-2010.

**Table 4-4: Summary of Maximum Measured $O_3$ Concentrations in Vicinity of HEF, 2008 to 2010**

| | | | | | Concentration ($\mu g/m^3$) | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Distance | | | 1-Hour | | 8-Hour | | |
| | | to HEF | Measurement Period | | | 2nd | | 2nd | 3-year Average |
| Site No. | Location | (km) | Year | Months | Highest | Highest | Highest | Highest | 4th Highest |
| **Ozone [a]** | **Florida AAQS:** | | | | **NA** | **235** | **NA** | **NA** | **147** |
| 12-055-0003 | Sebring | 2 | 2008 | Jan-Dec | 153.0 | 151.0 | 135.4 | 135.4 | 127.5 |
| | | | 2009 | Jan-Dec | 156.9 | 153.0 | 135.4 | 127.5 | 125.5 |
| | | | 2010 | Jan-Dec | 125.5 | 121.6 | 107.9 | 105.9 | 113.8 |

Note: NA = not applicable.
AAQS = ambient air quality standard.

[a] On March 27, 2008, EPA promulgated revised AAQS for ozone. The $O_3$ standard was modified to be 0.075 ppm (147 $\mu g/m^3$) for the 8-hour average; achieved when the 3-year average of 99th percentile values is 0.075 ppm or less. FDEP has not yet adopted the revised standards.

Source: State of Florida Air Quality Quicklook Reports 2008-2010.

**Table 4-5: Summary of Maximum Measured $NO_2$ Concentrations near HEF, 2008 to 2010**

| Site No. | Location | Distance to HEF (km) | Measurement Period Year | Measurement Period Months | Concentration (µg/m³) 1-Hour Highest | 1-Hour 2nd Highest | 1-Hour 98th Percentile | 1-Hour 3 Year Avg. 98th Percentile | Annual Average |
|---|---|---|---|---|---|---|---|---|---|
| **Nitrogen Dioxide** | **Florida AAQS:** | | | | **NA** | **NA** | **NA** | **189[a]** | **100** |
| 121-151-1006 | Sarasota | 114 | 2008 | Jan-Dec | 58.3 | 56.4 | -- | -- | 5.6 |
| | | | 2009 | Jan-Dec | 52.6 | 50.8 | -- | -- | 6.6 |
| | | | 2010 | Jan-Dec | 56.4 | 48.9 | 45.1 | 45.1 | 7.5 |

Note: NA = not applicable.
AAQS = ambient air quality standard.

Source: State of Florida Air Quality Quicklook Reports 2008-2010.

**Table 5-1: BACT Determinations for $PM/PM_{10}/PM_{2.5}$ Emissions from Biomass-Fired Electric Utility and Industrial Boilers**

| Company | State | RBLC ID / Permit Number | Permit Date | Throughput | Pollutant | Emission Limits: As Provided in RACT/BACT/LAER Clearinghouse | Emission Limits: Converted to lb/MMBtu[a] | Control Equipment Description | Removal Efficiency % |
|---|---|---|---|---|---|---|---|---|---|
| **BAGASSE** | | | | | | | | | |
| Southeast Renewable Fuels | FL | PSD-FL-412 | 12/22/2010 | 488 MMBtu/hr | $PM/PM_{10}$ | 0.015 lb/MMBtu | 0.015 | Wet Cyclone & ESP | |
| U.S. Sugar Corp. - Clewiston - Boiler No. 8 | FL | PSD-FL-333B[b] | 4/7/2006 | 936 MMBtu/hr | PM | 0.025 lb/MMBtu | 0.025 | Wet Cyclone & ESP | 99 |
| New Hope Power Partnership - Boilers A, B, C | FL | PSD-FL-196(P)[b] | 6/6/2005 | 760 MMBtu/hr | PM | 0.026 lb/MMBtu | 0.026 | Cyclones & ESPs | -- |
| U.S. Sugar Corp. - Clewiston - Boiler No. 8 | FL | FL-0257 | 11/21/2003 | 936 MMBtu/hr | PM | 0.026 lb/MMBtu | 0.026 | Wet Cyclone & ESP | 99 |
| Atlantic Sugar Association - Boiler No. 5 | FL | PSD-FL-078B[b] | 7/1/2002 | 255.3 MMBtu/hr | PM | 0.15 lb/MMBtu | 0.150 | Wet Scrubber | -- |
| **ALL OTHER BIOMASS** | | | | | | | | | |
| Georgia Power Co. | GA | GA-0140 | 12/3/2010 | 328 MMBtu/hr | $PM_{10}$ | 0.04 lb/MMBtu (3-hour avg) | 0.040 | ESP & Multiclone | -- |
| NRG Energy | CT | CT-0156 | 4/6/2010 | 600 MMBtu/hr | PM | 0.026 lb/MMBtu | 0.026 | Dry ESP | 95 |
| Sappi Fine Paper PLC | MN | MN-0078 | 10/28/2009 | 430 MMBtu/hr | $PM_{2.5}$ | 13.5 lb/hr | 0.031 | ESP & Multiclone | 99 |
| Aspen Power LLC | TX | TX-0555 | 10/26/2009 | 693 MMBtu/hr | PM | 0.012 lb/MMBtu (30-day rolling avg) | 0.012 | ESP | -- |
| Loblolly Green Power | SC | 1780-0051CA | 9/3/2009 | 675 MMBtu/hr | $PM/PM_{10}$ | 0.029 lb/MMBtu | 0.029 | ESP | |
| Koda Energy Boilers Nos. 1 and 3 | MN | MN-0074 | 8/23/2007 | 308 MMBtu/hr | PM | 0.03 lb/MMBtu | 0.030 | Cyclone and ESP | -- |
| Simpson Paper Company | WA | WA-0335 | 5/22/2007 | 595 MMBtu/hr | $PM_{10}$ | 0.02 lb/MMBtu | 0.020 | ESP | 99 |
| Sierra Pacific Industries - Skagit Co. Lumber Mill | WA | WA-0327[c] | 1/25/2006 | 430 MMBtu/hr | $PM_{10}$ | 0.02 lb/MMBtu (24-hr avg) | 0.020 | ESP | 99 |
| Darrington Energy LLC | WA | WA-0329 | 2/11/2005 | 403 MMBtu/hr | $PM_{10}$ | 0.02 lb/MMBtu (24-hr avg) | 0.020 | Dry ESP | -- |
| Temple Inland Inc. - Rome | GA | GA-0114 | 10/13/2004 | 856 MMBtu/hr | $PM_{10}$ | 0.025 lb/MMBtu | 0.025 | ESP | -- |
| Powerminn 9090 LLC | MN | MN-0057 | 10/23/2002 | 792 MMBtu/hr | $PM_{10}$ | 0.02 lb/MMBtu (30-day avg) | 0.020 | Fabric Filter | 99 |
| Sierra Pacific Industries - Aberdeen Div. | WA | WA-0298 | 10/17/2002 | 310 MMBtu/hr | PM | 0.02 lb/MMBtu (24-hr avg) | 0.020 | ESP | -- |
| S.D. Warren Co. - Boiler No. 2 | ME | ME-0021 | 11/27/2001 | 1,300 MMBtu/hr | PM | 171 TPY | 0.030 | Mechanical Dust Collector & ESP | 99 |
| District Energy St. Paul Inc. | MN | MN-0046 | 11/15/2001 | 550 MMBtu/hr | PM | 0.03 lb/MMBtu | 0.030 | Cyclone & ESP | 99 |
| Trigen Biopower | GA | GA-0117 | 5/24/2001 | 302.2 MMBtu/hr | $PM_{10}$ | 8 lb/hr | 0.026 | ESP & Wet Scrubber | -- |
| **NON-BACT LIMITS** | | | | | | | | | |
| FBEnergy | FL | 0810226-001-AC | 6/8/2010 | 833 MMBtu/hr | $PM/PM_{10}$ | 0.01 lb/MMBtu | 0.01 | ESP | |
| Burlington Electric Department | VT | AOP-07-020 | 4/21/2008 | 750 MMBtu/hr | PM | 9.7 lb/hr | 0.013 | Mechanical Dust Collectors & ESP | -- |
| Burlington Electric Department | VT | AOP-07-020 | 4/21/2008 | 750 MMBtu/hr | PM | 0.02 lb/MMBtu | 0.020 | Mechanical Dust Collectors & ESP | -- |
| Biomass Energy | OH | OH-0307 | 4/4/2006 | 318 MMBtu/hr | $PM_{10}$ | 3.97 lb/hr | 0.012 | Pulse Jet Baghouse | -- |
| **FLUIDIZED BED BOILERS** | | | | | | | | | |
| We Energies | WI | 10-SDD-058 | 3/28/2011 | 800 MMBtu/hr | $PM_{10}/PM_{2.5}$ | 0.024 lb/MMBtu | 0.024 | Fabric Filter | -- |
| Greenhunter Energy | CA | 1732D-1 | 7/20/2010 | 180 MMBtu/hr | $PM_{10}/PM_{2.5}$ | 0.01 lb/MMBtu | 0.010 | Fabric Filter | -- |
| Gainesville Renewable Energy Center | FL | PSD-FL-411 | 12/28/2010 | 1,358 MMBtu/hr | $PM/PM_{10}$ | 0.015 lb/MMBtu | 0.015 | Fabric Filter | -- |
| Laidlaw Berlin Biopower, LLC | NH | NH-0018 | 7/26/2010 | 1,013 MMBtu/hr | $PM/PM_{10}/PM_{2.5}$ | 0.01 lb/MMBtu | 0.010 | Baghouse | -- |
| Highlands Ethanol | FL | PSD-FL-406 | 3/22/2010 | 218 MMBtu/hr | $PM/PM_{10}$ | 0.01 lb/MMBtu | 0.01 | Fabric Filter Baghouse | -- |
| Lindale Renewable Energy LLC | TX | TX-0553 | 1/8/2010 | 657 MMBtu/hr | PM | 0.02 lb/MMBtu (30-day rolling avg) | 0.020 | ESP | -- |
| ADAGE Hamilton LLC | FL | 0470016-001-AC | 1/15/2010 | 800 MMBtu/hr | $PM/PM_{10}$ | 22.0 lb/hr | 0.028 | Fabric Filter Baghouse | 99.9 |
| | | | | | | 0.029 lb/MMBtu | 0.029 | Fabric Filter Baghouse | 99.9 |
| Public Service of New Hampshire - Schiller Station | NH | NH-0013 | 10/25/2004 | 720 MMBtu/hr | $PM_{10}$ | 0.025 lb/MMBtu | 0.025 | Fabric Filter | 99 |
| | | | | | | 0.03 lb/MMBtu (30-day rolling avg) | 0.030 | NSPS Limit; Fabric Filter | 99 |

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, May 2011. Based on utility and large industrial-size boilers/furnaces greater than 250 MMBtu/hr firing biomass.

Notes:

[a] To convert from lb/hr, the emission limit was divided by the throughput rate. To convert from TPY, 8,760 hr/yr operation is assumed.

[b] This information obtained from actual PSD permit, not Clearinghouse.

[c] From the draft BACT determination.

**Table 5-2: PM/$PM_{10}$ Control Technology Feasibility Analysis for HEF Cogeneration Boiler**

| PM Abatement Method | Technique Now Available | Estimated Efficiency | Feasible and Demonstrated? (Y/N) | Rank Based on Control Efficiency | Employed by HEF Boiler? (Y/N) |
|---|---|---|---|---|---|
| Fuel Techniques | Fuel Substitution | NA | Y | 7 | N |
| Pretreatment | Settling Chambers | < 10% | Y | 6 | N |
| | Elutriators | < 10% | Y | 6 | N |
| | Momentum Separators | 10 - 20% | Y | 5 | N |
| | Mechanically-Aided Separators | 20 - 30% | Y | 4 | N |
| | Cyclones | 60 - 90% | Y | 3 | Y |
| Electrostatic Precipitators (ESP) | Dry ESP | >97% | Y | 1 | Y |
| | Wet ESP | >97% | Y | 1 | N |
| | Wire-Plate ESP | >97% | Y | 1 | N |
| | Wire-Pipe ESP | >97% | Y | 1 | N |
| Fabric Filters | Shaker-Cleaned | >97% | Y[a] | 1 | N |
| | Reverse-Air | >97% | Y[a] | 1 | N |
| | Pulse-Jet | >97% | Y[a] | 1 | N |
| Wet Scrubbers | Spray Chambers | 50 - 95 % | Y | 2 | N |
| | Packed-Bed | 50 - 95 % | Y | 2 | N |
| | Impingement Plate | 50 - 95 % | Y | 2 | N |
| | Venturi | 50 - 95 % | Y | 2 | N |
| | Orifice | 50 - 95 % | Y | 2 | N |
| | Condensation | 50 - 95 % | Y | 2 | N |

Note: NTF = Not Technically Feasible.

[a] Technically feasible for fluidized bed boiler only.

**Table 5-3: BACT Determinations for $NO_x$ Emissions from Biomass-Fired Electric Utility and Industrial Boilers**

| Company | State | RBLC ID | Permit Date | Throughput | Emission Limits: As Provided in RACT/BACT/LAER Clearinghouse | Emission Limits: Converted to lb/MMBtu[a] | Control Equipment Description | Removal Efficiency % |
|---|---|---|---|---|---|---|---|---|
| **BAGASSE** | | | | | | | | |
| Southeast Renewable Fuels | FL | PSD-FL-412 | 12/22/2010 | 488 MMBtu/hr | 0.10 lb/MMBtu | 0.10 | SNCR or SCR | 70 |
| U.S. Sugar Corp. - Clewiston - Boiler No. 7 | FL | PSD-FL-389 | 12/6/2007 | 738 MMBtu/hr | 0.31 lb/MMBtu | 0.310 | Boiler Design and Operation | – |
| New Hope Power Partnership - Boilers A, B, C | FL | PSD-FL-196(P)[c] | 6/6/2005 | 760 MMBtu/hr | 0.15 lb/MMBtu | 0.150 | SNCR, Good Combustion Practices | – |
| U.S. Sugar Corp. - Clewiston - Boiler No. 8 | FL | FL-0257 | 11/21/2003 | 936 MMBtu/hr | 0.14 lb/MMBtu | 0.140 | SNCR, Good Combustion & Operating Practices | 50 |
| Atlantic Sugar Association - Boiler No. 5 | FL | PSD-FL-078B[c] | 7/1/2002 | 255.3 MMBtu/hr | 0.16 lb/MMBtu | 0.160 | Good Combustion Practices | – |
| **ALL OTHER BIOMASS** | | | | | | | | |
| NRG Energy | CT | CT-0156 | 4/6/2010 | 600 MMBtu/hr | 0.06 lb/MMBtu | 0.060 | Regenerative SCR | 70 |
| Boise White Paper, LLC | AL | AL-0250 | 3/23/2010 | 435 MMBtu/hr | 0.3 lb/MMBtu (3-hr avg) | 0.300 | Low NOx burners | 60 |
| Lindale Renewable Energy LLC | TX | TX-0553 | 1/8/2010 | 657 MMBtu/hr | 0.15 lb/MMBtu (30-day rolling avg) | 0.150 | SNCR | – |
| Aspen Power LLC | TX | TX-0555 | 10/26/2009 | 693 MMBtu/hr | 0.075 lb/MMBtu (30-day rolling avg) | 0.075 | SCR | – |
| Loblolly Green Power | SC | 1780-0051CA | 9/3/2009 | 675 MMBtu/hr | | | | |
| Koda Energy Boiler No. 3 | MN | MN-0074 | 8/23/2007 | 308 MMBtu/hr | 0.25 lb/MMBtu | 0.250 | SNCR | – |
| Simpson Paper Company | WA | WA-0335 | 5/22/2007 | 595 MMBtu/hr | 0.2 lb/MMBtu (30-day rolling avg) | 0.200 | Proper combustion control with Overfire Air | – |
| Archer Daniels Midland Company | ND | ND-0022 | 5/1/2006 | 280 MMBtu/hr | 0.2 lb/MMBtu (30-day rolling avg) | 0.200 | Combustion Control | 30 |
| Sierra Pacific Industries - Skagit Co Lumber Mill | WA | WA-0327[b] | 1/25/2006 | 430 MMBtu/hr | 0.13 lb/MMBtu (Calendar Day) | 0.130 | SNCR | 48 |
| Fort James Operating Company, Inc.--Old Town | ME | A-180-71-AI-A[c] | 7/28/2004 | 265.2 MMBtu/hr | 0.25 lb/MMBtu | 0.250 | Low $NO_X$ burners, overfire air, FGR | – |
| Del-Tin Fiber LLC | AR | AR-0072 | 2/28/2003 | 291 MMBtu/hr | 87.2 lb/hr | 0.300 | Low $NO_X$ burners & SNCR | – |
| Palm Beach Power Corporation | FL | PSD-FL-329[b] | 1/16/2003 | 760 MMBtu/hr | 0.15 lb/MMBtu | 0.150 | SNCR | – |
| Powerminn 9090 LLC | MN | MN-0057 | 10/23/2002 | 792 MMBtu/hr | 0.16 lb/MMBtu (30-day avg) | 0.160 | SNCR | 50 |
| **NON-BACT LIMITS** | | | | | | | | |
| We Energies | WI | 10-SDD-058 | 3/28/2011 | 800 MMBtu/hr | 0.10 lb/MMBtu (30-day rolling avg) | 0.010 | SNCR | – |
| Greenhunter Energy | CA | 1732D-1 | 7/20/2010 | 180 MMBtu/hr | 0.014 lb/MMBtu (30-day rolling avg) | 0.014 | SCR | 95 |
| FBEnergy | FL | 0810226-001-AC | 6/8/2010 | 833 MMBtu/hr | 0.018 lb/MMBtu (12-month rolling) | 0.018 | SCR | – |
| Clean Power Berlin, LLC | NH | NH-0016 | 9/25/2009 | 40.75 TPH Wood | 0.065 lb/MMBtu | 0.065 | SCR w/ Staged Combustion | 70 |
| Concord Steam Corporation | NH | NH-0015 | 2/27/2009 | 305 MMBtu/hr | 0.065 lb/MMBtu (30-day rolling avg) | 0.065 | SCR | 70 |
| Burlington Electric Department | VT | AOP-07-020 | 4/21/2008 | 750 MMBtu/hr | 0.23 lb/MMBtu | 0.230 | – | – |
| | | | | | 145 lb/hr | 0.193 | – | – |
| | | | | | 0.075 lb/MMBtu (CEMS Quarterly Avg) | 0.075 | Regenerative SCR | – |
| Biomass Energy | OH | OH-0307 | 4/4/2006 | 318 MMBtu/hr | 27.98 lb/hr | 0.088 | SCR | 80 |
| **FLUIDIZED BED BOILERS** | | | | | | | | |
| Gainesville Renewable Energy Center | FL | PSD-FL-411 | 12/28/2010 | 1,358 MMBtu/hr | 0.070 lb/MMBtu (30-day rolling) | 0.070 | SCR | – |
| Laidlaw Berlin Biopower, LLC | NH | NH-0018 | 7/26/2010 | 1013 MMBtu/hr | 0.06 lb/MMBtu | 0.06 | SCR with Ammonia Injection | – |
| Highlands Ethanol | FL | PSD-FL-406 | 3/22/2010 | 218 MMBtu/hr | 0.075 lb/MMBtu | 0.075 | SNCR | – |
| ADAGE Hamilton LLC | FL | 0470016-001-AC | 1/15/2010 | 800 MMBtu/hr | 53.1 lb/hr (12-month rolling average) | 0.066 | SCR | – |
| | | | | | 0.30 lb/MMBtu (30-day rolling avg) | 0.30 | SCR | – |

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, May 2011. Based on utility and large industrial-size boilers/furnaces greater than 250 MMBtu/hr firing biomass.

Notes:

[a] To convert from lb/hr, the emission limit was divided by the throughput rate. To convert from TPY, 8,760 hr/yr operation is assumed.

[b] From the draft BACT determination.

[c] This information obtained from actual PSD permit, not Clearinghouse.



Golder Associates

**Table 5-4: $NO_x$ Control Technology Feasibility Analysis for HEF Cogeneration Boiler**

| $NO_x$ Abatement Method | Technique Now Available | Estimated Efficiency | Feasible and Demonstrated? (Y/N) | Rank Based on Control Efficiency | Employed by HEF Boiler? (Y/N) |
|---|---|---|---|---|---|
| 1. Removal of nitrogen | Ultra-Low Nitrogen Fuel | No Data | Y | 5 | Y |
| 2. Oxidation of $NO_x$ with subsequent absorption | Inject Oxidant | 60 - 80% | NTF | NTF | N |
| | Non-Thermal Plasma Reactor (NTPR) | 60 - 80% | NTF | NTF | N |
| 3. Chemical reduction of $NO_x$ | Selective Catalytic Reduction (SCR) | 75% | Y | 1 | N |
| | Regenerative Selective Catalytic Reduction (RSCR) | 75% | Y | 1 | N |
| | Selective Non-Catalytic Reduction (SNCR) | 50 - 60% | Y | 2 | Y |
| | EMx ($SCONO_X$)™ | 35 - 80% | NTF | NTF | N |
| 4. Reducing residence time at peak temperature | Air Staging of Combustion | 50 - 65% | Y | 3 | Y |
| | Fuel Staging of Combustion | 50 - 65% | Y | 3 | N |
| | Inject Steam | 50 - 65% | Y | 3 | N |
| 5. Reducing peak temperature | Flue Gas Recirculation (FGR) | 15 - 25% | Y | 4 | N |
| | Natural Gas Reburning (NGR) | 15 - 25% | Y | 4 | N |
| | Over Fire Air (OFA) | 15 - 25% | Y | 4 | Y |
| | Less Excess Air (LEA) | 15 - 25% | Y | 4 | N |
| | Combustion Optimization | 15 - 25% | Y | 4 | Y |
| | Low $NO_x$ Burners (LNB) (natural gas/fuel oil only) | 15 - 25% | Y | 4 | Y |

Note: NTF = Not Technically Feasible.

**Table 5-5: Summary of Air Emission Control Capital and Operating Costs for HEF Bagasse Boiler**

| Control Option | Capital Cost | Annual Cost |
|---|---|---|
| Wet Cyclone/DSI/ESP[a] | 6,800,000 | 1,180,000 |
| Wet Cyclone/DSI/ESP/SNCR[a] | 8,800,000 | 1,830,000 |
| Wet Cyclone/DSI/ESP/SCR[a,b] | 10,500,000 | 1,960,000 |
| Wet Cyclone/DSI/ESP/SCR/Ox-Cat[a,b] | 11,900,000 | 2,320,000 |

[a] Includes wet cyclone capital cost of $500,000 and annual cost of $80,000 per year.

[b] Includes $600,000 capital cost and $80,000 per year annual cost for relocatoing boiler air heater.

**Table 5-6: Summary of Top-down BACT Analysis Impact Results for HEF Biomass Boiler**

| Control Alternative | Control Efficiency (%) | Controlled Emissions (lb/MMBtu) | Maximum Emissions (TPY) | Emissions Reduction (TPY) | Economic Impacts: Installed Capital Cost ($) | Total Annualized Cost ($/yr) | Average Cost Effectiveness ($/ton) | Incremental Cost Effectiveness ($/ton) |
|---|---|---|---|---|---|---|---|---|
| **NO$_x$** | | | | | | | | |
| SCR | 70 | 0.075 | 138.2 | 322.5 | 3,700,000 | 780,000 | 2,418 | 2,821 |
| SNCR | 60 | 0.10 | 184.3 | 276.5 | 2,000,000 | 650,000 | 2,351 | 2,351 |
| Uncontrolled | 0 | 0.25 | 460.8 | -- | -- | -- | -- | -- |
| **SO$_2$** | | | | | | | | |
| Lime Spray Dryer/FF | 84 | 0.070 | 128.3 | 673.7 | 8,000,000 | 1,700,000 | 2,523 | 7,214 |
| DSI/ESP | 75 | 0.109 | 200.4 | 601.6 | 6,800,000 | 1,180,000 | 1,961 | |
| No Add-On Control | 0 | 0.435 | 802.0 | -- | -- | -- | -- | -- |
| **CO + VOC** | | | | | | | | |
| Oxidation Catalyst | 60/40 | 0.12+0.01 | 239.6 | 344.7 | 1,400,000 | 360,000 | 1,044 | (705) |
| Advanced Over-Fire Air | 25 | 0.225+0.013 | 438.2 | 146.1 | 3,100,000 | 500,000 | 3,423 | 3,423 |
| Modern Over-Fire Air | 0 | 0.30+0.017 | 584.3 | -- | -- | -- | -- | -- |
| **NOx + CO + VOC** | | | | | | | | |
| SCR+ Oxidation Catalyst | | | 377.8 | 667.2 | 5,100,000 | 1,140,000 | 1,709 | (41) |
| SNCR + Advanced Over-Fire Air | | | 622.5 | 422.5 | 5,100,000 | 1,150,000 | 2,722 | 3,423 |
| SNCR + Modern Over-Fire Air | | | 768.6 | 276.5 | 2,000,000 | 650,000 | 2,351 | 2,351 |
| Uncontrolled | | | 1,045.1 | -- | -- | -- | -- | -- |

Table 5-7: BACT Determinations for $SO_2$ Emissions from Biomass-Fired Industrial and Electric Utility Boilers

| | | | | | Emission Limits | | | |
|---|---|---|---|---|---|---|---|---|
| Company | State | RBLC ID | Permit Date | Throughput | As Provided in RACT/BACT/LAER Clearinghouse | Converted to lb/MMBtu[a] | Control Equipment Description | % Efficiency |
| **BAGASSE** | | | | | | | | |
| Southeast Renewable Fuels | FL | PSD-FL-412 | 12/22/2010 | 488 MMBtu/hr | 0.06 lb/MMBtu (30-day rolling avg.) | 0.06 | Low S fuels, Dry Sorbent Injection | |
| New Hope Power Partnership - Boilers A, B, C | FL | PSD-FL-196(P)[b] | 6/6/2005 | 760 MMBtu/hr | 0.20 lb/MMBtu (24-hr rolling avg.) | 0.20 | Low S supplemental fuel; ESP; SNCR; carbon injection | -- |
| | | | | | 0.10 lb/MMBtu (30-day rolling avg.) | 0.10 | Low S supplemental fuel; ESP; SNCR; carbon injection | -- |
| | | | | | 0.06 lb/MMBtu (12-month rolling avg.) | 0.060 | Low S supplemental fuel; ESP; SNCR; carbon injection | |
| U.S. Sugar Corp. - Clewiston - Boiler No. 8 | FL | FL-0257 | 11/21/2003 | 936 MMBtu/hr | 0.06 lb/MMBtu | 0.060 | Fuel specifications: bagasse and distillate oil (<0.05 % S by wt.) | -- |
| **ALL OTHER BIOMASS** | | | | | | | | |
| NRG Energy | CT | CT-0156 | 4/6/2010 | 600 MMBtu/hr | 0.025 lb/MMBtu (3-hr avg.) | 0.025 | Low sulfur fuels | -- |
| Lindale Renewable Energy LLC | TX | TX-0553 | 1/8/2010 | 657 MMBtu/hr | 0.025 lb/MMBtu (30-day rolling avg) | 0.025 | -- | -- |
| Aspen Power LLC | TX | TX-0555 | 10/26/2009 | 693 MMBtu/hr | 0.025 lb/MMBtu (30-day rolling avg) | 0.025 | -- | -- |
| Loblolly Green Power | SC | 1780-0051CA | 9/3/2009 | 675 MMBtu/hr | | | | |
| Smurfit Stone Container Corp. | AL | AL-0223 | 7/14/2006 | 620 MMBtu/hr | 93 lb/hr (3-hr avg.) | 0.150 | No controls feasible | -- |
| Archer Daniels Midland Company | ND | ND-0022 | 5/1/2006 | 280 MMBtu/hr | 0.47 lb/MMBtu | 0.470 | No controls feasible | -- |
| Inland Paperboard and Packaging (Gaylord) | LA | LA-0188 | 11/23/2004 | 787.5 MMBtu/hr | 1209.8 lb/hr | 1.536 | Limit annual fuel oil capacity factor to <= 10% | -- |
| Smurfit-Stone - Stevenson | AL | AL-0198 | 9/30/2002 | 620 MMBtu/hr | 0.1 lb/MMBtu | 0.100 | No controls feasible | -- |
| Meadwestvaco Kentucky Inc. | KC | KY-0085 | 2/27/2002 | 631 MMBtu/hr | 0.8 lb/MMBtu | 0.800 | No controls feasible | -- |
| S.D. Warren Co. - Boiler No. 2 | ME | ME-0021 | 11/27/2001 | 1,300 MMBtu/hr | 0.27 lb/MMBtu | 0.270 | Sodium-based wet scrubber | -- |
| Sierra Pacific Industries | WA | WA-0327[c] | 1/25/2006 | 430 MMBtu/hr | 0.025 lb/MMBtu (3-hr avg.) | 0.025 | No controls feasible | -- |
| Grayling Generating Station L.P. | MI | MI-0285 | 9/18/2001 | 523 MMBtu/hr | 11.2 lb/hr (24-hr avg.) | 0.021 | Multicyclones, ESP, SNCR | -- |
| **NON-BACT LIMITS** | | | | | | | | |
| Greenhunter Energy | CA | 1732D-1 | 7/20/2010 | 180 MMBtu/hr | 0.015 lb/MMBtu (12-month rolling) | 0.015 | Woody Biomass, dry sorbent injection | |
| FBEnergy | FL | 0810226-001-AC | 6/8/2010 | 833 MMBtu/hr | 0.015 lb/MMBtu (12-month rolling) | 0.015 | Woody Biomass, dry sorbent injection | |
| Burlington Electric Department | VT | AOP-07-020 | 4/21/2008 | 750 MMBtu/hr | 100 lb/MMBtu | 0.133 | No controls | -- |
| Biomass Energy | OH | OH-0307 | 4/4/2006 | 318 MMBtu/hr | 22.13 lb/hr | 0.070 | Spray Dryer Absorber or Dry Sodium Bicarbonate Injection System | 20 |
| **FLUIDIZED BED BOILERS** | | | | | | | | |
| Gainesville Renewable Energy Center | FL | PSD-FL-411 | 12/28/2010 | 1,358 MMBtu/hr | 0.029 lb/MMBtu | 0.029 | Clean Fuels (biomass) and Dry Sorbent Injection | |
| Laidlaw Berlin Biopower, LLC | NH | NH-0018 | 7/26/2010 | 1013 MMBtu/hr | 0.012 lb/MMBtu | 0.012 | Wood Fuel Sorbent Injection | -- |
| Highlands Ethanol | FL | PSD-FL-406 | 3/22/2010 | 218 MMBtu/hr | 0.06 lb/MMBtu (30-day rolling) | 0.06 | Bubbling fluidized bed, limestone injection | -- |
| ADAGE Hamilton LLC | FL | 0470016-001-AC | 1/15/2010 | 800 MMBtu/hr | 34.1 lb/hr (12-month avg, rolled monthly) | 0.043 | CEMS & IDSIS (lime, limestone, trona or sodium bicarbonate) | -- |
| Public Service of New Hampshire | NH | NH-0013 | 10/25/2004 | 720 MMBtu/hr | 0.02 lb/MMBtu (24-hr avg.) | 0.020 | Lime injection | 70 |

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, May 2011. Based on utility and large industrial-size boilers/furnaces greater than 250 MMBtu/hr firing biomass.

Notes:

[a] To convert from lb/hr, the emission limit was divided by the throughput rate. To convert from lb/day, assumed 24 hr/day operation.

[b] This information obtained from actual PSD permit, not Clearinghouse.

[c] From the draft BACT determination.

**Table 5-8: $SO_2$ Control Technology Feasibility Analysis for HEF Cogeneration Boiler**

| $SO_2$ Abatement Method | Technique Now Available | Estimated Efficiency | Feasible and Demonstrated? (Y/N) | Rank Based on Control Efficiency | Employed by HEF Boiler? (Y/N) |
|---|---|---|---|---|---|
| Sorbent Injection | Sorbent Furnace Injection | 50% | Y | 6 | N |
| | Sorbent Economiser Injection | 50% | Y | 6 | N |
| | Sorbent Duct Injection | 75% | Y | 5 | Y |
| Wet Flue Gas Desulfurization | Various | 50 - 98% | Y | 1 | N |
| Spray Dryer Scrubbers | Lime or Calcium Oxide | 70 - 96% | Y | 3 | N |
| Regenerative Process | Elemental Sulphur Recovery | >95% | Y | 2 | N |

Note: NTF = Not Technically Feasible.

**Table 5-9: BACT Determinations for SAM Emissions from Biomass-Fired Electric Utility and Industrial Boilers**

| Company | State | RBLC ID | Permit Date | Throughput | | Emission Limits As Provided in RACT/BACT/LAER Clear. | | Emission Limits Converted to lb/MMBtu[b] | Control Equipment Description | Removal % Efficiency |
|---|---|---|---|---|---|---|---|---|---|---|
| **BAGASSE** | | | | | | | | | | |
| Southeast Renewable Fuels | FL | PSD-FL-412 | 12/22/2010 | 488 | MMBtu/hr | 0.003 | lb/MMBtu | 0.003 | Fuel Specifications: Bagasse and Distillate Oil (<0.05% S) | |
| U.S. Sugar Corp. - Clewiston - Boiler No. 8 | FL | FL-0257 | 11/21/2003 | 936 | MMBtu/hr | 0.004 [a] | lb/MMBtu | 0.004 | Fuel Specifications: Bagasse and Distillate Oil (<0.05% S) | -- |
| **ALL OTHER BIOMASS** | | | | | | | | | | |
| Smurfit Stone Container Corp. - Stevenson Mill | AL | AL-0223 | 7/14/2006 | 620 | MMBtu/hr | 13.6 | lb/hr (3-hr avg.) | 0.022 | No Controls Feasible | -- |
| Grayling Generating Station L.P. | MI | MI-0285 | 9/18/2001 | 523 | MMBtu/hr | 0.003 | lb/MMBtu | 0.003 | No Controls Feasible | -- |
| **FLUIDIZED BED BOILERS** | | | | | | | | | | |
| Gainesville Renewable Energy Center | FL | PSD-FL-411 | 12/28/2010 | 1,358 | MMBtu/hr | 1.4 | lb/hr | 0.0010 | Clean Fuels (biomass) and Dry Sorbent Injection | |
| Laidlaw Berlin Biopower, LLC | NH | NH-0018 | 7/26/2010 | 1013 | MMBtu/hr | 0.002 | lb/MMBtu | 0.002 | Wood Fuel Sorbent Injection | -- |

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, May 2011. Based on utility and large industrial-size boilers/furnaces greater than 250 MMBtu/hr firing biomass.

Notes:

[a] $SO_2$ is a surrogate for SAM. These are expected emissions limits.

[b] To convert from lb/hr, the emission limit was divided by the throughput rate.

**Table 5-10: BACT Determinations for CO Emissions from Biomass-Fired Electric Utility and Industrial Boilers**

| Company | State | RBLC ID | Permit Date | Throughput | Emission Limits: As Provided in RACT/BACT/LAER Clearinghouse | Emission Limits: Converted to lb/MMBtu[a] | Control Equipment Description | Removal Efficiency % |
|---|---|---|---|---|---|---|---|---|
| **BAGASSE** | | | | | | | | |
| Southeast Renewable Fuels | FL | PSD-FL-412 | 12/22/2010 | 488 MMBtu/hr | 0.10 lb/MMBtu, 30-day rolling avg. | 0.10 | Good combustion practices: Oxidation catalyst as needed | |
| U.S. Sugar Corp. - Clewiston - Boiler No. 8 | FL | PSD-FL-333B[b] | 4/7/2006 | 936 MMBtu/hr | 400 ppmvd @ 7% O2 | 0.38 | Good Combustion & Operating Practices | -- |
| New Hope Power Partnership - Boilers A, B, C | FL | PSD-FL-196(P)[b] | 6/6/2005 | 760 MMBtu/hr | 0.35 lb/MMBtu (12-month rolling avg.) | 0.35 | Good Combustion & Operating Practices | -- |
| New Hope Power Partnership - Boilers A, B, C | FL | PSD-FL-196(P)[b] | 6/6/2005 | 760 MMBtu/hr | 0.50 lb/MMBtu (30-day rolling avg.) | 0.50 | Good Combustion & Operating Practices | -- |
| U.S. Sugar Corp. - Clewiston - Boiler No. 8 | FL | FL-0257 | 11/21/2003 | 936 MMBtu/hr | 0.38 lb/MMBtu (12-month rolling avg.) | 0.38 | Good Combustion & Operating Practices | -- |
| Atlantic Sugar Association - Boiler No. 5 | FL | PSD-FL-078B[b] | 7/1/2002 | 255.3 MMBtu/hr | 6.5 lb/MMBtu | 6.50 | Good Combustion & Operating Practices | -- |
| **ALL OTHER BIOMASS** | | | | | | | | |
| Georgia Power Co. | GA | GA-0140 | 12/3/2010 | 328 MMBtu/hr | 0.45 lb/MMBtu (3-hour avg) | 0.45 | Good combustion practices | -- |
| NRG Energy | CT | CT-0156 | 4/6/2010 | 600 MMBtu/hr | 0.026 lb/MMBtu | 0.026 | Oxidation Catalyst | 70 |
| Lindale Renewable Energy LLC | TX | TX-0553 | 1/8/2010 | 657 MMBtu/hr | 0.31 lb/MMBtu (30-day rolling avg) | 0.31 | Good Combustion Practices | -- |
| Loblolly Green Power | SC | 1780-0051CA | 9/3/2009 | 675 MMBtu/hr | 0.075 lb/MMBtu | 0.075 | Oxidation Catalyst | |
| Koda Energy Boiler No. 3 | MN | MN-0074 | 8/23/2007 | 308 MMBtu/hr | 0.43 lb/MMBtu (30-day rolling avg.) | 0.43 | Good Combustion Practices | -- |
| Simpson Paper Company | WA | WA-0335 | 5/22/2007 | 595 MMBtu/hr | 0.35 lb/MMBtu | 0.35 | Overfire Air System | -- |
| Archer Daniels Midland Company | ND | ND-0022 | 5/1/2006 | 280 MMBtu/hr | 0.63 lb/MMBtu | 0.63 | Good Combustion Practices | -- |
| Sierra Pacific Industries - Skagit Co Lumber Mill | WA | WA-0327[c] | 1/25/2006 | 430 MMBtu/hr | 659 TPY | 0.35 | -- | -- |
| Darrington Energy LLC | WA | WA-0329 | 2/11/2005 | 403 MMBtu/hr | 0.35 lb/MMBtu (24-hr avg) | 0.35 | Good Combustion Practices | -- |
| Inland Paperboard and Packaging (Gaylord) | LA | LA-0188 | 11/23/2004 | 787.5 MMBtu/hr | 491.5 lb/hr | 0.624 | Overfire Air & Good Combustion Practices | -- |
| Temple Inland Inc - Rome | GA | GA-0114 | 10/13/2004 | 856 MMBtu/hr | 368 ppm @ 3% $O_2$ | -- | Staged Combustion & Good Combustion Practices | -- |
| Boise Cascade Corp - Deridder Paper Mill | LA | LA-0178 | 11/14/2003 | 454.29 MMBtu/hr | 149.9 lb/hr | 0.33 | Good Equipment Design & Proper Combustion Techniques | -- |
| Del-Tin Fiber LLC | AR | AR-0072 | 2/28/2003 | 291 MMBtu/hr | 228.3 lb/hr | 0.785 | Good Combustion Practices | -- |
| Powerminn 9090 LLC | MN | MN-0057 | 10/23/2002 | 792 MMBtu/hr | 0.24 lb/MMBtu (24-hr avg) | 0.24 | Good Combustion Practices | -- |
| Sierra Pacific Industries - Aberdeen Div. | WA | WA-0298 | 10/17/2002 | 310 MMBtu/hr | 0.35 lb/MMBtu | 0.35 | Good Combustion Practices | -- |
| S.D. Warren Co. - Boiler No. 2 | ME | ME-0021 | 11/27/2001 | 1300 MMBtu/hr | 520 lb/hr | 0.40 | Good Boiler Design & Combustion Practices | -- |
| District Energy St. Paul Inc. | MN | MN-0046 | 11/15/2001 | 550 MMBtu/hr | 0.3 lb/MMBtu | 0.30 | Good Combustion Practices | -- |
| Trigen Biopower | GA | GA-0117 | 5/24/2001 | 302.2 MMBtu/hr | 90.7 lb/hr | 0.30 | Good Design & Combustion Practices | -- |
| International Paper Company - Riegelwood Mill | NC | NC-0092 | 5/10/2001 | 600 MMBtu/hr | 0.5 lb/MMBtu | 0.50 | Good Combustion Practices | -- |
| **NON-BACT LIMITS** | | | | | | | | |
| Greenhunter Energy | CA | 1732D-1 | 7/20/2010 | 180 MMBtu/hr | 0.10 lb/MMBtu (30-day rolling avg) | 0.10 | SCR | |
| FBEnergy | FL | 0810226-001-AC | 6/8/2010 | 833 MMBtu/hr | 0.028 lb/MMBtu (30-day rolling avg) | 0.028 | Oxidation Catalyst | |
| Aspen Power LLC | TX | TX-0555 | 10/26/2009 | 693 MMBtu/hr | 0.075 lb/MMBtu (12 month rolling avg) | 0.075 | Good Combustion Practices | -- |
| Burlington Electric Department | VT | AOP-07-020 | 4/21/2008 | 750 MMBtu/hr | 1500 ppm | -- | -- | -- |
| Biomass Energy | OH | OH-0307 | 4/4/2006 | 318 MMBtu/hr | 31.8 lb/hr | 0.10 | Oxidation Catalyst | 50 |
| **FLUIDIZED BED BOILERS** | | | | | | | | |
| We Energies | WI | 10-SDD-058 | 3/28/2011 | 800 MMBtu/hr | 0.12 lb/MMBtu | 0.120 | Good Combustion Practices | -- |
| Gainesville Renewable Energy Center | FL | PSD-FL-411 | 12/28/2010 | 1,358 MMBtu/hr | 0.08 lb/MMBtu | 0.080 | Good Combustion Practices | -- |
| Highlands Ethanol | FL | PSD-FL-406 | 3/22/2010 | 218 MMBtu/hr | 0.10 lb/MMBtu (30-day rolling) | 0.10 | Good Combustion Practices | -- |
| ADAGE Hamilton LLC | FL | 0470016-001-AC | 1/15/2010 | 800 MMBtu/hr | 56.0 lb/hr (12-month avg. rolled monthly) | 0.070 | CEMS | -- |
| Public Service of New Hampshire - Schiller Station | NH | NH-0013 | 10/25/2004 | 720 MMBtu/hr | 0.1 lb/MMBtu (24-hr avg) | 0.10 | Good Combustion Practices | -- |

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, May 2011. Based on utility and large industrial-size boilers/furnaces greater than 250 MMBtu/hr firing biomass.

Notes:

[a] To convert from lb/hr, the emission limit was divided by the throughput rate. To convert from TPY, 8,760 hr/yr operation is assumed.

[b] This information obtained from actual PSD permit, not Clearinghouse.

[c] From the draft BACT determination.



Golder Associates

**Table 5-11: CO Control Technology Feasibility Analysis for HEF Cogeneration Boiler**

| CO Abatement Method | Technique Now Available | Estimated Efficiency | Feasible and Demonstrated? (Y/N) | Rank Based on Control Efficiency | Employed by HEF Boiler? (Y/N) |
|---|---|---|---|---|---|
| Catalytic Oxidation | Tail-End Oxidation Catalyst | 60-80% | Y | 1 | N |
| | Regenerative Oxidation Catalyst | 60-80% | Y | 1 | N |
| Enhanced Over-Fire Air Systems | Nalco Mobotec OFA | 70% | Y | 2 | N |
| | Synterprise Ecojet | 70% | Y | 2 | N |
| Good Combustion Practices | Air Staging of Combustion | 50 - 75% | Y | 3 | Y |
| | Increased Gas Residence Time | 50 - 75% | Y | 3 | Y |
| | Combustion Optimization | 50 - 75% | Y | 3 | Y |
| Incinerators | Thermal | >80% | NTF | NTF | N |
| | Catalytic | >80% | NTF | NTF | N |

Note: NTF = Not Technically Feasible.

Table 5-12: BACT Determinations for VOC Emissions from Biomass-Fired Electric Utility and Industrial Boilers

| Company | State | RBLC ID | Permit Date | Throughput | Emission Limits As Provided in RACT/BACT/LAER Clearinghouse | Emission Limits Converted to lb/MMBtu[a] | Control Equipment Description | Removal Efficiency % |
|---|---|---|---|---|---|---|---|---|
| **BAGASSE** | | | | | | | | |
| Southeast Renewable Fuels | FL | PSD-FL-412 | 12/22/2010 | 488 MMBtu/hr | 0.010 lb/MMBtu | 0.010 | Good combustion practices; Oxidation catalyst as needed | -- |
| New Hope Power Partnership - Boilers A, B, C | FL | PSD-FL-196(P)[b] | 6/6/2005 | 760 MMBtu/hr | 0.05 lb/MMBtu | 0.050 | Clean fuels | -- |
| U.S. Sugar Corp. - Clewiston - Boiler No. 8 | FL | FL-0257 | 11/21/2003 | 936 MMBtu/hr | 0.05 lb/MMBtu | 0.050 | Good combustion & Operating practices | -- |
| Atlantic Sugar Association - Boiler No. 5 | FL | PSD-FL-078B[b] | 7/1/2002 | 255 MMBtu/hr | 0.25 lb/MMBtu | 0.250 | Good combustion practices | -- |
| **ALL OTHER BIOMASS** | | | | | | | | |
| Georgia Power Co. | GA | GA-0140 | 12/3/2010 | 328 MMBtu/hr | 0.05 lb/MMBtu (3-hour avg) | 0.050 | Good combustion practices | -- |
| NRG Energy | CT | CT-0156 | 4/6/2010 | 600 MMBtu/hr | 0.01 lb/MMBtu | 0.010 | Oxidation Catalyst | 70 |
| Boise White Paper, LLC | AL | AL-0250 | 3/23/2010 | 435 MMBtu/hr | 0.03 lb/MMBtu (3-hr avg) | 0.030 | -- | 60 |
| Aspen Power LLC | TX | TX-0555 | 10/26/2009 | 693 MMBtu/hr | 0.01 lb/MMBtu (30-day rolling avg) | 0.010 | -- | -- |
| Potlatch Corporation - Ozan Unit | AR | AR-0083 | 7/26/2005 | 110,000 Steam | 0.034 lb/MMBtu | 0.034 | Good combustion practices | -- |
| Boise Cascade Corp - Deridder Paper Mill | LA | LA-0178 | 11/14/2003 | 454.29 MMBtu/hr | 73.77 TPY | 0.037 | Good Equipment Design & Proper Combustion Techniques | -- |
| Del-Tin Fiber LLC | AR | AR-0072 | 2/28/2003 | 291 MMBtu/hr | 21.2 lb/hr | 0.073 | Closed loop system | 95 |
| S.D. Warren Co. - Boiler No. 2 | ME | ME-0021 | 11/27/2001 | 1,300 MMBtu/hr | 0.007 lb/MMBtu | 0.007 | Good combustion practices | -- |
| **NON-BACT LIMITS** | | | | | | | | |
| Greenhunter Energy | CA | 1732D-1 | 7/20/2010 | 180 MMBtu/hr | 0.0085 lb/MMBtu | 0.0085 | SCR, good combustion practices | |
| Biomass Energy | OH | OH-0307 | 4/4/2006 | 318 MMBtu/hr | 4.06 lb/hr | 0.013 | Good combustion practices and use of oxidation catalyst | -- |
| Loblolly Green Power | SC | 1780-0051CA | 9/3/2009 | 675 MMBtu/hr | 0.004 lb/MMBtu | 0.004 | Oxidation catalyst | |
| **FLUIDIZED BED BOILERS** | | | | | | | | |
| We Energies | WI | 10-SDD-058 | 3/28/2011 | 800 MMBtu/hr | -- | -- | Comply with CO limit. | -- |
| Gainesville Renewable Energy Center | FL | PSD-FL-411 | 12/28/2010 | 1,358 MMBtu/hr | 0.009 lb/MMBtu | 0.009 | Good Combustion Practices | -- |
| Highlands Ethanol | FL | PSD-FL-406 | 3/22/2010 | 218 MMBtu/hr | 0.005 lb/MMBtu | 0.005 | Good Combustion Practices | -- |
| Public Service of New Hampshire - Schiller Station | NH | NH-0013 | 10/25/2004 | 720 MMBtu/hr | 0.005 lb/MMBtu (24-hr avg) | 0.005 | Good combustion practices | -- |

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, May 2011. Based on utility and large industrial-size boilers/furnaces greater than 250 MMBtu/hr firing biomass.

Notes:

[a] To convert from lb/hr, the emission limit was divided by the throughput rate. To convert from TPY, 8,760 hr/yr operation is assumed.

[b] This information obtained from actual PSD permit, not Clearinghouse.

[c] From the draft BACT determination.

**Table 5-13: Add-on VOC Control Technology Feasibility Analysis for HEF Cogeneration Boiler**

| VOC Abatement Method | Technique Now Available | Estimated Efficiency | Feasible and Demonstrated? (Y/N) | Rank Based on Control Efficiency | Employed by HEF Boiler? (Y/N) |
|---|---|---|---|---|---|
| Refrigerated Condensors | Surface | Variable | NTF | NTF | N |
| | Contact | Variable | NTF | NTF | N |
| Carbon Adsorbers | Fixed Regenerative Bed | Variable | NTF | NTF | N |
| | Disposable/Rechargeable Cannisters | Variable | NTF | NTF | N |
| | Traveling Bed Adsorbers | Variable | NTF | NTF | N |
| | Fluid Bed Adsorbers | Variable | NTF | NTF | N |
| | Chromatographic Baghouse | Variable | NTF | NTF | N |
| Catalytic Oxidation | Tail-End SCR/RSCR | 40-80% | Y | 1 | N |
| | Conventional SCR | Variable | NTF | NTF | N |
| Over-Fire Air Systems | Nalco Mobotec OFA | 70% | Y | 2 | N |
| | Synterprise Ecojet | 70% | Y | 2 | N |
| Good Combustion Practices | Air Staging of Combustion | 50 - 75% | Y | 3 | Y |
| | Increased Gas Residence Time | 50 - 75% | Y | 3 | Y |
| | Combustion Optimization | 50 - 75% | Y | 3 | Y |
| Destruction Controls | Flares | Variable | NTF | NTF | N |
| Incinerators | Thermal | >80% | NTF | NTF | N |
| | Catalytic | >80% | NTF | NTF | N |

Note: NTF = Not Technically Feasible.

**Table 6-1: Major Features of the AERMOD Model, Version 11103**

| **AERMOD Model Features** |
|---|
| • Plume dispersion/growth rates are determined by the profile of vertical and horizontal turbulence, vary with height, and use a continuous growth function. |
| • In a convective atmosphere, uses three separate algorithms to describe plume behavior as it comes in contact with the mixed layer lid; in a stable atmosphere, uses a mechanically mixed layer near the surface. |
| • Polar or Cartesian coordinate systems for receptor locations can be included directly or by an external file reference. |
| • Urban model dispersion is input as a function of city size and population density; sources can also be modeled individually as urban sources. |
| • Stable plume rise: uses Briggs equations with winds and temperature gradients at stack top up to half-way up to plume rise. Convective plume rise: plume superimposed on random convective velocities. |
| • Procedures suggested by Briggs (1974) for evaluating stack-tip downwash. |
| • Has capability of simulating point, volume, area, and multi-sized area sources. |
| • Accounts for the effects of vertical variations in wind and turbulence (Brower et al., 1998). |
| • Uses measured and computed boundary layer parameters and similarity relationships to develop vertical profiles of wind, temperature, and turbulence (Brower et al., 1998). |
| • Concentration estimates for 1-hour to annual average times. |
| • Creates vertical profiles of wind, temperature, and turbulence using all available measurement levels. |
| • Terrain features are depicted by use of a controlling hill elevation and a receptor point elevation. |
| • Modeling domain surface characteristics are determined by selected direction and month/season values of surface roughness length, albedo, and Bowen ratio. |
| • Contains both a mechanical and convective mixed layer height, the latter based on the hourly accumulation of sensible heat flux. |
| • The method of Pasquill (1976) to account for buoyancy-induced dispersion. |
| • A default regulatory option to set various model options and parameters to EPA-recommended values. |
| • Contains procedures for calm-wind and missing data for the processing of short term averages. |

Note: AERMOD = The American Meteorological Society and EPA Regulatory Model.

Source: Paine et al., 2007.

**Table 6-2: Modeled Emission Rates Used for the Significant Impact Analysis**

| Source ID | Model ID | Description | Modeled Emission Rate[a] | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | $SO_2$ | | | | | | $PM_{10}$ | | | | $PM_{2.5}$ | | | | CO | | $NO_x$ | | | | SAM[b] | |
| | | | Annual[a] | | 24-hour | | 1- and 3-hour | | Annual[a] | | 24-hour | | Annual[a] | | 24-hour | | 8-hour/1-hour | | Annual[a] | | 1-hour | | 24-hour | |
| **Point Sources** | | | (TPY) | (g/s) | (lb/hr) | (g/s) | (lb/hr) | (g/s) | (TPY) | (g/s) | (lb/hr) | (g/s) | (TPY) | (g/s) | (lb/hr) | (g/s) | (lb/hr) | (g/s) | (TPY) | (g/s) | (lb/hr) | (g/s) | (lb/hr) | (g/s) |
| Bagasse Boiler | BOILER | Bagasse Boiler | 200.4 | 6.28 | 64.2 | 8.09 | 70.6 | 8.90 | 27.6 | 0.87 | 6.9 | 0.87 | 18.0 | 0.56 | 4.9 | 0.62 | 1,192.1 | 150.20 | 184.3 | 5.78 | 126.1 | 15.89 | 3.15 | 0.40 |
| Cooling Tower | COOLTWR | Cooling Tower | -- | -- | -- | -- | -- | -- | 0.19 | 0.0054 | 0.043 | 0.0054 | 0.19 | 0.0054 | 0.043 | 0.0054 | -- | -- | -- | -- | -- | -- | -- | -- |
| Flare | FLARE | Truck Loading Rack Flare | 0.0090 | 0.00026 | 0.0057 | 0.00072 | 0.0057 | 0.00072 | 0.052 | 0.0015 | 0.034 | 0.0043 | 0.052 | 0.0015 | 0.034 | 0.0043 | 3.61 | 0.45 | 1.04 | 0.030 | 0.66 | 0.083 | -- | -- |
| Ash Silo | ASHSILO | Bagfilter for Boiler Ash Silo | -- | -- | -- | -- | -- | -- | 0.847 | 0.024 | 0.21 | 0.026 | 0.847 | 0.024 | 0.21 | 0.026 | -- | -- | -- | -- | -- | -- | -- | -- |
| Lime Silo 1 | LIMEWWT | Bagfilter for Lime Silo for Wastewater Tre | -- | -- | -- | -- | -- | -- | 0.002 | 0.000058 | 0.21 | 0.026 | 0.002 | 0.000058 | 0.21 | 0.026 | -- | -- | -- | -- | -- | -- | -- | -- |
| Lime Silo 2 | LIMEDSI | Bagfilter for Lime Silo for DSI | -- | -- | -- | -- | -- | -- | 0.00042 | 0.000012 | 0.21 | 0.026 | 0.00042 | 0.000012 | 0.21 | 0.026 | -- | -- | -- | -- | -- | -- | -- | -- |

**Area and Volume Sources**

| | | | Source Type | $PM_{10}$ | | | | $PM_{2.5}$ | | | | Area Source Size | | $PM_{10}$ Modeled Emissions | | $PM_{2.5}$ Modeled Emissions | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Annual | | 24-hour | | Annual | | 24-hour | | | | Annual | 24-hour | Annual | 24-hour |
| | | | | (TPY) | (g/s) | (lb/hr) | (g/s) | (TPY) | (g/s) | (lb/hr) | (g/s) | ($ft^2$) | ($m^2$) | ($g/m^2$-s) | ($g/m^2$-s) | ($g/m^2$-s) | ($g/m^2$-s) |
| Biomass Materials Handling | BIOFUG | Conveyors, belts, and screens | Area | 0.047 | 0.0014 | 0.051 | 0.006 | 0.0071 | 0.0002 | 0.0077 | 0.001 | 32,500 | 3,019 | 4.49E-07 | 2.13E-06 | 6.80E-08 | 3.23E-07 |
| Biomass Pile Wind Erosion | BIOFUGWE | Biomass storage pile wind erosion | Area | 0.11 | 0.0031 | 0.29 | 0.037 | 0.11 | 0.0031 | 0.29 | 0.037 | 100,000 | 9,290 | 3.33E-07 | 3.95E-06 | 3.33E-07 | 3.95E-06 |
| Biomass Pile Vehicular Maint. | BIOFUGVM | Biomass storage vehicular maintenance | Area | 1.39 | 0.040 | 0.45 | 0.057 | 0.14 | 0.0040 | 0.046 | 0.0058 | 100,000 | 9,290 | 4.30E-06 | 6.10E-06 | 4.34E-07 | 6.24E-07 |
| Biomass Truck Traffic[b] | BIOTRK | Sorghum and wood deliveries, ash, and lime hauling | Line | 0.29 | 0.0085 | 0.067 | 0.0084 | 0.072 | 0.0021 | 0.017 | 0.0021 | -- | -- | -- | -- | -- | -- |
| Other Truck Traffic | ETHTRK | Ethanol and denaturant/gasoline deliveries | Line | 0.011 | 0.00033 | 0.0027 | 0.00034 | 0.0028 | 8.05E-05 | 6.67E-04 | 8.40E-05 | -- | -- | -- | -- | -- | -- |

[a] Annual averages are based on the annual emission rate in TPY over 8,040 hours for the boiler, or 8,760 for all other sources.

[b] SAM emissions are included only for the visibility analysis. SAM is not a PSD pollutant.

**Table 6-3: Model Parameters Used for the Significant Impact Analysis**

| Source ID | Model ID | Description | UTM NAD83 East (m) | UTM NAD83 North (m) | Physical Height (ft) | Physical Height (m) | Physical Diameter (ft) | Physical Diameter (m) | Operating Temperature (°F) | Operating Temperature (K) | Operating Velocity (fps) | Operating Velocity (m/s) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Point Sources** | | | | | | | | | | | | |
| Bagasse Boiler | BOILER | Bagasse Boiler | 466,365 | 3,008,958 | 150 | 45.7 | 14 | 4.3 | 340 | 444 | 22.1 | 6.74 |
| Cooling Tower | COOLTWR | Cooling Tower | 466,512 | 3,008,828 | 35 | 10.7 | 33 | 10.1 | 77 | 298 | 4.1 | 1.26 |
| Flare | FLARE | Truck Loading Rack Flare | 466,387 | 3,009,253 | 30 | 9.1 | 1.0 | 0.30 | 1,832 | 1,273 [a] | 5.2 | 1.60 |
| Ash Silo | ASHSILO | Bagfilter for Boiler Ash Silo | 466,257 | 3,008,965 | 35 | 10.7 | 1.5 | 0.46 | 77 | 298 | 23.6 | 7.19 |
| Lime Silo 1 | LIMEWWT | Bagfilter for Lime Silo for Wastewater Treatment | 466,461 | 3,008,832 | 35 | 10.7 | 1.5 | 0.46 | 77 | 298 | 23.6 | 7.19 |
| Lime Silo 2 | LIMEDSI | Bagfilter for Lime Silo for DSI | 466,346 | 3,008,942 | 35 | 10.7 | 1.5 | 0.46 | 77 | 298 | 23.6 | 7.19 |

| Area and Volume Sources | Model ID | Description | UTM NAD83 East (m) | UTM NAD83 North (m) | Source Type | Release Height (ft) | Release Height (m) | Length x-dimension[c] (ft) | Length x-dimension[c] (m) | Length y-dimension[d] (ft) | Length y-dimension[d] (m) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Biomass Materials Handling | BIOFUG | Conveyors, belts, and screens | 466,331 | 3,008,877 | Area | 15 | 4.6 | 325.0 | 99.1 | 100.0 | 30.5 |
| Biomass Pile Wind Erosion | BIOFUGWE | Biomass storage pile wind erosion | 466,289 | 3,008,809 | Area | 35 | 10.7 | 400.0 | 121.9 | 250.0 | 76.2 |
| Biomass Pile Vehicular Maint. | BIOFUGVM | Biomass storage vehicular maintenance | 466,289 | 3,008,809 | Area | 35 | 10.7 | 400.0 | 121.9 | 250.0 | 76.2 |
| Biomass Truck Traffic[b] | BIOTRK | Sorghum and wood deliveries, ash, and lime hauling | 466,506 | 3,009,135 [b] | Line | 11.25 | 3.4 | 27.6 | 8.4 | 22.5 | 6.9 |
| Other Truck Traffic | ETHTRK | Ethanol and denaturant/gasoline deliveries | 466,434 | 3,009,136 [b] | Line | 11.25 | 3.4 | 28.0 | 8.5 | 22.5 | 6.9 |

[a] Default temperature used in AERMOD for flare modeling.

[b] Truck traffic locations shown for one volume source only.

[c] The x-dimension for each volume source is equivalent to the side length for each volume source (Sigma y).

[d] The y-dimension for each volume source is equivalent to the vertical dimension (sigma Z).

**Table 6-4: Summary of the $SO_2$ Facilities Considered for Inclusion in the 24-Hour AAQS and PSD Class II Air Modeling Analyses**

| AIRS Number | Facility | County | UTM Coordinates East (km) | UTM Coordinates North (km) | Relative to Highlands Ethanol X (km) | Relative to Highlands Ethanol Y (km) | Relative to Highlands Ethanol Distance (km) | Relative to Highlands Ethanol Direction (deg) | Maximum 24-Hr/Annual $SO_2$ Emissions (TPY) | Q, (TPY) Emission Threshold [b,c] Dist x 20 | Include in Modeling Analysis ? |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Modeling Area - Included all facilities within Modeling Area | | | | | | | | | | | |
| 0550014 | Lake Placid Asphalt Plant | Highlands | 465.6 | 3,008.7 | -0.8 | -0.3 | 0.87 | 249 | 170.07 | SIA | YES |
| Screening Area - Exclude all facilities with emissions <10 TPY [d] | | | | | | | | | | | |
| 0550018 | Tampa Electric Co. - Philips Station | Highlands | 464.3 | 3,035.4 | -2.1 | 26.4 | 26.47 | 355 | 1,955.70 | 529.4 | YES |
| 0550061 | Highlands Ethanol | Highlands | 493.2 | 3,013.2 | 26.8 | 4.2 | 27.12 | 81 | 104.24 | 542.4 | NO |
| 0550060 | Compression Station No. 29 | Highlands | 494.3 | 3,012.4 | 27.9 | 3.4 | 28.10 | 83 | 18.86 | 562.0 | NO |
| 0550046 | Highlands County Dept. of Solid Waste | Highlands | 469.3 | 3,042.9 | 2.9 | 33.8 | 33.96 | 5 | 11.80 | 679.2 | NO |
| 0550003 | Progress Energy - Avon Park | Highlands | 451.4 | 3,050.5 | -15.0 | 41.5 | 44.12 | 340 | 5,054.52 | 882.3 | YES |
| 0270016 | Desoto County Energy Park | Desoto | 419.8 | 3,011.8 | -46.6 | 2.8 | 46.65 | 273 | 951.05 | 933.1 | YES |
| 0430008 | South Florida Thermal Services, Inc. | Glades | 489.2 | 2,966.6 | 22.8 | -42.4 | 48.15 | 152 | 93.71 | 963.0 | NO |
| 0930001 | Okeechobee Asphalt Plant | Okeechobee | 516.1 | 3,014.2 | 49.7 | 5.2 | 49.95 | 84 | 115.15 | 999.1 | NO |

Note: NA = Not applicable, ND = No data, SID = Significant impact distance for the project

[a] Highlands Ethanol East and North Coordinates (km) are: 466.4 3,009.0 km

[b] The significant impact distance for the project is estimated to be: 0.9 km

[c] Based on the North Carolina Screening Threshold method, a background facility is included in the modeling analysis if the facility is beyond the modeling area and its emission rate is greater than the product of Distance x 20.

[d] "Modeling Area" is the area in which the project is predicted to have a significant impact (0.9 km). EPA recommends that all sources within this area be modeled.
"Screening Area" is the significant impact distance for the HEF Facility of 0.9 km, plus 50 km beyond the modeling area. EPA recommends that sources be modeled that are expected to have a significant impact in the modeling area. Screening criteria within these areas are specified in the headers.

**Table 6-5: Summary of the $SO_2$ Facilities Considered for Inclusion in the 1-Hour AAQS Air Modeling Analysis**

| AIRS Number | Facility[c] | County | UTM Coordinates East (km) | UTM Coordinates North (km) | Relative to Highlands Ethanol X (km) | Relative to Highlands Ethanol Y (km) | Relative to Highlands Ethanol Distance (km) | Relative to Highlands Ethanol Direction (deg) | Maximum 1-Hour $SO_2$ Emissions (lb/hr) | Include in Modeling Analysis ? |
|---|---|---|---|---|---|---|---|---|---|---|
| Modeling Area - Included all facilities out to 10 km | | | | | | | | | | |
| 0550014 | Lake Placid Asphalt Plant | Highlands | 465.6 | 3,008.7 | -0.8 | -0.3 | 0.87 | 249 | 35.32 | YES |
| Facilities out to 50 km beyond SIA - Include if > 250 lb/hr | | | | | | | | | | |
| 0550018 | Tampa Electric Co. - Philips Station | Highlands | 464.3 | 3,035.4 | -2.1 | 26.4 | 26.47 | 355 | 923.82 | YES |
| 0550061 | Highlands Ethanol | Highlands | 493.2 | 3,013.2 | 26.8 | 4.2 | 27.12 | 81 | 23.80 | NO |
| 0550060 | Compression Station No. 29 | Highlands | 494.3 | 3,012.4 | 27.9 | 3.4 | 28.10 | 83 | 2.07 | NO |
| 0550046 | Highlands County Dept. of Solid Waste | Highlands | 469.3 | 3,042.9 | 2.9 | 33.8 | 33.96 | 5 | 2.32 | NO |
| 0550003 | Progress Energy - Avon Park | Highlands | 451.4 | 3,050.5 | -15.0 | 41.5 | 44.12 | 340 | 1,154.00 | YES |
| 0270016 | Desoto County Energy Park | Desoto | 419.8 | 3,011.8 | -46.6 | 2.8 | 46.65 | 273 | 197.38 | NO |
| 0430008 | South Florida Thermal Services, Inc. | Glades | 489.2 | 2,966.6 | 22.8 | -42.4 | 48.15 | 152 | 19.45 | NO |
| 0930001 | Okeechobee Asphalt Plant | Okeechobee | 516.1 | 3,014.2 | 49.7 | 5.2 | 49.95 | 84 | 23.90 | NO |
| 0430018 | Oldcaste Lawn and Garden Moore Haven | Glades | 492.0 | 2,961.3 | 25.6 | -47.7 | 54.13 | 152 | 4.10 | NO |

Note: NA = Not applicable, ND = No data, SID = Significant impact distance for the project

[a] Highlands Ethanol East and North Coordinates (km) are: 466.4 3,009.0 km

[b] The significant impact distance for the project is estimated to be: 4.75 km

[c] Facilities with less than 1 lb/hr past 10 km are excluded from the screening table.

[d] "Modeling Area" is the area in which the project is predicted to have a significant impact (4.75 km). EPA recommends that all sources within this area be modeled.
"Screening Area" is the significant impact distance for the HEF Facility of 4.75 km, plus 50 km beyond the modeling area. EPA recommends that sources be modeled that are expected to have a significant impact in the modeling area. Screening criteria within these areas are specified in the headers.

**Table 6-6: Summary of the $PM_{10}$ and $PM_{2.5}$ Facilities Considered for Inclusion in the AAQS and PSD Class II Air Modeling Analyses**

| AIRS Number | Facility | County | UTM Coordinates East (km) | UTM Coordinates North (km) | Relative to Highlands Ethanol X (km) | Relative to Highlands Ethanol Y (km) | Distance (km) | Direction (deg) | Maximum $PM_{10}$ Emissions (TPY) | Q, (TPY) Emission Threshold [b,c] (Dist - SID) x 20 | Include in Modeling Analysis ? |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Modeling Area - Included all facilities within Modeling Area | | | | | | | | | | | |
| 0550014 | Lake Placid Asphalt Plant | Highlands | 465.6 | 3,008.7 | -0.8 | -0.3 | 0.87 | 249 | 0.18 | SIA | YES |
| Screening Area - Exclude all facilities with emissions <10 TPY [d] | | | | | | | | | | | |
| 0550018 | Tampa Electric Company - Philips Station | Highlands | 464.3 | 3,035.4 | -2.1 | 26.4 | 26.47 | 355 | 72.10 | 471.4 | NO |
| 0550061 | Highlands Ethanol | Highlands | 493.2 | 3,013.2 | 26.8 | 4.2 | 27.12 | 81 | 36.96 | 484.4 | NO |
| 0270016 | Desoto County Energy Park | Desoto | 419.8 | 3,011.8 | -46.6 | 2.8 | 46.65 | 273 | 327.62 | 875.1 | NO |
| 0430008 | South Florida Thermal Servides, Inc. | Glades | 489.2 | 2,966.6 | 22.8 | -42.4 | 48.15 | 152 | 20.96 | 905.0 | NO |

Note: NA = Not applicable, ND = No data, SID = Significant impact distance for the project

[a] Highlands Ethanol East and North Coordinates (km) are: 466.4 3,009.0 km

[b] The significant impact distance for the project is estimated to be: 2.9 km

[c] Based on the North Carolina Screening Threshold method, a background facility is included in the modeling analysis if the facility is beyond the modeling area and its emission rate is greater than the product of (Distance-SID) x 20.

[d] "Modeling Area" is the area in which the project is predicted to have a significant impact (2.9 km). EPA recommends that all sources within this area be modeled.
"Screening Area" is the significant impact distance for the HEF Facility of 2.9 km, plus 50 km beyond the modeling area. EPA recommends that sources be modeled that are expected to have a significant impact in the modeling area. Screening criteria within these areas are specified in the headers.

Table 6-7: Summary of the 1-Hour $NO_x$ Facilities Considered for Inclusion in the AAQS Air Modeling Analysis

| AIRS Number | Facility | County | UTM Coordinates East (km) | UTM Coordinates North (km) | Relative to Highlands Ethanol X (km) | Y (km) | Distance (km) | Direction (deg) | Maximum Annual NOx Emissions (lb/hr) | Include in Modeling Analysis ? |
|---|---|---|---|---|---|---|---|---|---|---|
| Modeling Area - Included all facilities out to 10 km | | | | | | | | | | |
| 0550014 | Lake Placid Asphalt Plant | Highlands | 465.6 | 3,008.7 | -0.8 | -0.3 | 0.87 | 249 | 15.00 | YES |
| Facilities out to 50 km beyond SIA - Include if > 250 lb/hr | | | | | | | | | | |
| 0550018 | Tampa Electric Company - Philips Station | Highlands | 464.3 | 3,035.4 | -2.1 | 26.4 | 26.47 | 355 | 1,145.52 | YES |
| 0550061 | Highlands Ethanol | Highlands | 493.2 | 3,013.2 | 26.8 | 4.2 | 27.12 | 81 | 14.90 | NO |
| 0550060 | Compression Station No. 29 | Highlands | 494.3 | 3,012.4 | 27.9 | 3.4 | 28.10 | 83 | 1.01 | NO |
| 0550032 | TCSC Sebring Plant | Highlands | 469.5 | 3,038.4 | 3.1 | 29.4 | 29.55 | 6 | 1.30 | NO |
| 0550058 | Compressor Station No. 430C | Highlands | 472.5 | 3,041.7 | 6.1 | 32.7 | 33.26 | 11 | 6.67 | NO |
| 0550046 | Highlands County Dept. of Solid Waste | Highlands | 469.3 | 3,042.9 | 2.9 | 33.8 | 33.96 | 5 | 1.84 | NO |
| 0550003 | Progress Energy - Avon Park | Highlands | 451.4 | 3,050.5 | -15.0 | 41.5 | 44.12 | 340 | 990.18 | YES |
| 0270016 | Desoto County Energy Park | Desoto | 419.8 | 3,011.8 | -46.6 | 2.8 | 46.65 | 273 | 128.20 | NO |
| 0430008 | South Florida Thermal Services, Inc. | Glades | 489.2 | 2,966.6 | 22.8 | -42.4 | 48.15 | 152 | 14.37 | NO |
| 0430018 | Oldcastle Lawn and Garden Moore Haven | Glades | 492.0 | 2,961.3 | 25.6 | -47.7 | 54.13 | 152 | 30.00 | NO |
| 0510015 | Southern Gardens Citrus Processing Corp. | Hendry | 487.5 | 2,957.6 | 21.1 | -51.4 | 55.57 | 158 | 45.48 | NO |
| 0270003 | Peace River Citrus Products | Desoto | 409.8 | 3,010.3 | -56.6 | 1.3 | 56.64 | 271 | 21.59 | NO |
| 0490344 | McBars, LLC - Limestone | Hardee | 411.0 | 3,027.3 | -55.4 | 18.3 | 58.31 | 288 | 4.68 | NO |
| 0930109 | Biomass Processing Facility - Okeechobee | Okeechobee | 525.2 | 3,017.4 | 58.8 | 8.4 | 59.37 | 82 | 10.95 | NO |
| 0510004 | Citrus Belle | Hendry | 456.4 | 2,950.3 | -10.0 | -58.7 | 59.56 | 190 | 26.51 | NO |
| 7770048 | Better Roads, Inc. | Hillsborough | 425.0 | 2,963.0 | -41.4 | -46.0 | 61.88 | 222 | 4.33 | NO |
| 7775172 | Plant No. 7 - Punta Gorda | Charlotte | 423.6 | 2,964.0 | -42.9 | -45.1 | 62.19 | 224 | 16.51 | NO |

Note: NA = Not applicable, ND = No data, SID = Significant impact distance for the project

[a] Highlands Ethanol East and North Coordinates (km) are: 466.4 3,009.0 km

[b] The significant impact distance for the project is estimated to be: 12 km

[c] Facilities with less than 1 lb/hr past 10 km are excluded from the screening table.

[d] "Modeling Area" is the area in which the project is predicted to have a significant impact (12 km). EPA recommends that all sources within this area be modeled.
"Screening Area" is the significant impact distance for the HEF Facility of 12 km, plus 50 km beyond the modeling area. EPA recommends that sources be modeled that are expected to have a significant impact in the modeling area. Screening criteria within these areas are specified in the headers.

**Table 6-8: Summary of Building Dimensions Used in the Modeling Analysis**

| Building Description | Model ID | Height | | Length | | Width | |
|---|---|---|---|---|---|---|---|
| | | (ft) | (m) | (ft) | (m) | (ft) | (m) |
| Store Room | STORERM | 35.0 | 10.7 | 160.0 | 48.8 | 60.0 | 18.3 |
| Maintenance | MAINT | 35.0 | 10.7 | 60.0 | 18.3 | 120.0 | 36.6 |
| Garage | GARAGE | 30.0 | 9.1 | 80.0 | 24.4 | 50.0 | 15.2 |
| Office/Lab | OFFICE | 30.0 | 9.1 | 80.0 | 24.4 | 50.0 | 15.2 |
| Distillation | DIST | 35.0 | 10.7 | 160.0 | 48.8 | 50.0 | 15.2 |
| Fermentation | FERM | 35.0 | 10.7 | 50.0 | 15.2 | 160.0 | 48.8 |
| Evaporation | EVAP | 35.0 | 10.7 | 200.0 | 61.0 | 60.0 | 18.3 |
| Boiler Building | BLRBLD | 120.0 | 36.6 | 60.0 | 18.3 | 80.0 | 24.4 |
| Air Pollution Control Housing | APCDBLD | 78.0 | 23.8 | 25.0 | 7.6 | 65.0 | 19.8 |
| Turbine Building | TURBINE | 60.0 | 18.3 | 40.0 | 12.2 | 50.0 | 15.2 |
| Cooling Tower | COOLTWR | 35.0 | 10.7 | 40.0 | 12.2 | 80.0 | 24.4 |

**Table 6-9: Maximum Predicted Impacts for HEF Project Only Compared to EPA Class II Significant Impact Levels**

| Pollutant | Averaging Time | Maximum Predicted Concentration [a] (µg/m³) | Receptor Location UTM- East (m) | Receptor Location UTM- North (m) | Time Period (YYMMDDHH) | EPA Class II Significant Impact Levels (µg/m³) |
|---|---|---|---|---|---|---|
| $SO_2$ | Annual | 0.58 | 465,800 | 3,008,900 | NA | 1 |
| | 24-Hour | 8.1 | 466,600 | 3,009,400 | 04090624 | 5 |
| | 3-Hour | 23.7 | 466,146 | 3,009,372 | 02123115 | 25 |
| | 1-Hour | 29.7 | 466,000 | 3,009,200 | 5 Year Avg. | 7.9[c] |
| $PM_{2.5}$ | Annual | 0.43 | 466,245 | 3,008,772 | 5 Year Avg. | 0.3 |
| | 24-Hour | 5.2 | 466,524 | 3,008,768 | 5 Year Avg. | 1.2 |
| $PM_{10}$ | Annual | 1.5 | 466,245 | 3,008,772 | NA | 1 |
| | 24-Hour | 11.2 | 466,338 | 3,008,771 | 04020324 | 5 |
| $NO_2$ (Tier 1) | Annual | 0.63 | 465,800 | 3,008,900 | NA | 1 |
| | 1-Hour | 53.1 | 466,000 | 3,009,200 | 5 Year Avg. | 7.6[d] |
| $NO_2$[b] (Tier 2) | Annual | 0.47 | 465,800 | 3,008,900 | NA | 1 |
| | 1-Hour | 42.5 | 466,000 | 3,009,200 | 5 Year Avg. | 7.6[d] |
| CO | 8-Hour | 296.8 | 465,900 | 3,009,200 | 04051216 | 500 |
| | 1-Hour | 562.1 | 466,045 | 3,009,287 | 03080116 | 2,000 |

Note: YYMMDDHH = Year, Month, Day, Hour Ending

[a] Concentrations are based on concentrations predicted using 5 years of meteorological data from 2001 to 2005 of surface and upper air data from the National Weather Service stations at Fort Myers Southwest Florida Regional (RSW) Airport and Tampa International Airport, respectively.

[b] A $NO_x$ to $NO_2$ converstion factor of 75% applies for the annual averaging time, and 80% for the 1-hour averaging time, based on EPA's Guidline on Air Quality Models.

[c] EPA has not yet defined a significant impact level for $SO_2$ 1-hour impacts. However, interim guidance documents suggest a level of 3 ppb (7.9 µg/m³).

[d] EPA has not yet defined a significant impact level for $NO_2$ 1-hour impacts. However, interim guidance documents suggest a level of 4 ppb (7.6 µg/m³).

**Table 6-10: Maximum Predicted Impacts for HEF Project Only Compared to EPA Class I Significant Impact Levels at ENP**

| Pollutant | Averaging Time | Maximum Predicted Concentration [a] (µg/m³) | Receptor Location UTM- East (m) | Receptor Location UTM- North (m) | Time Period (YYMMDDHH) | EPA Class I Significant Impact Levels (µg/m³) |
|---|---|---|---|---|---|---|
| For receptors out to 50 km in the direction of ENP | | | | | | |
| $SO_2$ | Annual | 0.0091 | 461,174 | 2,959,274 | NA | 0.1 |
| | 24-Hour | 0.25 | 467,273 | 2,959,008 | 02101724 | 0.2 |
| | 3-Hour | 0.92 | 466,400 | 2,959,000 | 05011803 | 1.0 |
| $PM_{2.5}$ | Annual | 0.0010 | 467,273 | 2,959,008 | 5 Year Avg. | 0.06 |
| | 24-Hour | 0.061 | 475,940 | 2,959,919 | 5 Year Avg. | 0.07 |
| $PM_{10}$ | Annual | 0.0019 | 467,273 | 2,959,008 | NA | 0.2 |
| | 24-Hour | 0.10 | 475,940 | 2,959,919 | 05122324 | 0.3 |
| $NO_2$ (Tier 1) | Annual | 0.0086 | 461,174 | 2,959,274 | NA | 0.1 |
| $NO_2$[b] (Tier 2) | Annual | 0.0064 | 461,174 | 2,959,274 | NA | 0.1 |
| For receptors out to 100 km in the direction of ENP | | | | | | |
| $SO_2$ | 24-Hour | 0.13 | 468,145 | 2,909,015 | 02101724 | 0.2 |

Note: YYMMDDHH = Year, Month, Day, Hour Ending

[a] Concentrations are based on concentrations predicted using 5 years of meteorological data from 2001 to 2005 of surface and upper air data from the National Weather Service stations at Fort Myers Southwest Florida Regional (RSW) Airport and Tampa International Airport, respectively.

[b] A $NO_X$ to $NO_2$ converstion factor of 75% applies for the annualaveraging time, based on EPA's Guidline on Air Quality Models.



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Table 6-11: Maximum Predicted $SO_2$, $PM_{2.5}$, $PM_{10}$, and $NO_2$ Impacts for All Sources, Compared to the AAQS

| Averaging Time and Rank | Maximum Concentration (µg/m³) [a] Total | Modeled Sources | Background | Receptor Location UTM- East (m) | UTM- North (m) | Time Period (YYMMDDHH) | AAQS (µg/m³) |
|---|---|---|---|---|---|---|---|
| $SO_2$ | | | | | | | |
| 24-Hour, HSH | 54.1 | 27.9 | 26.2 | 465,400 | 3,008,600 | 04092724 | 260 |
| 1-Hour, 99th Perc. | 94.7 | 76.4 | 18.3 | 465,400 | 3,008,600 | NA | 196.5 |
| $PM_{2.5}$ | | | | | | | |
| Annual, Highest 5yr Avg. | 7.5 | 1.0 | 6.5 | 465,400 | 3,008,600 | NA | 15 |
| 24-Hour, 98th Perc. 5yr Avg. | 19.2 | 4.5 | 14.7 | 465,400 | 3,008,600 | NA | 35 |
| $PM_{10}$ | | | | | | | |
| Annual, Highest | 22.4 | 2.4 | 20.0 | 466,245 | 3,008,772 | NA | 50 |
| 24-Hour, H6H | 72.9 | 12.9 | 60.0 | 466,300 | 3,008,700 | 04092024 | 150 |
| $NO_2$ (Tier 1) | | | | | | | |
| 1-Hour, 98th Perc. 5yr Avg. | 85.7 | 40.6 | 45.1 | 465,400 | 3,008,600 | NA | 189 |
| $NO_2$[b] (Tier 2) | | | | | | | |
| 1-Hour, 98th Perc. 5yr Avg. | 77.5 | 32.4 | 45.1 | 465,400 | 3,008,600 | NA | 189 |

Note: YYMMDDHH = Year, Month, Day, Hour Ending
HSH = Highest, second-highest
H6H = Highest, sixth-highest

[a] Concentrations are based on concentrations predicted using 5 years of meteorological data from 2001 to 2005 of surface and upper air data from the National Weather Service stations at Fort Myers Southwest Florida Regional (RSW) Airport and Tampa International Airport, respectively.

[b] A $NO_X$ to $NO_2$ converstion factor of 80% applies for the 1-hour averaging time, based on EPA's Guidline on Air Quality Models.

**Table 6-12: Maximum Predicted $SO_2$ and $PM_{10}$ Impacts for All Sources, Compared to the PSD Class II Increments**

| Averaging Time and Rank | Maximum Concentration [a] (µg/m$^3$) | Receptor Location UTM- East (m) | Receptor Location UTM- North (m) | Time Period (YYMMDDHH) | PSD Class II Increment (µg/m$^3$) |
|---|---|---|---|---|---|
| $SO_2$ | | | | | |
| 24-Hour, HSH | 27.9 | 465,400 | 3,008,600 | 04092724 | 91 |
| $PM_{2.5}$ | | | | | |
| Annual, Highest | 1.1 | 465,400 | 3,008,600 | NA | 4 |
| 24-Hour, HSH | 7.6 | 465,700 | 3,008,900 | 04092724 | 9 |
| $PM_{10}$ | | | | | |
| Annual, Highest | 2.4 | 466,245 | 3,008,772 | NA | 17 |
| 24-Hour, HSH | 9.6 | 466,338 | 3,008,771 | 02021624 | 30 |

Note: YYMMDDHH = Year, Month, Day, Hour Ending
HSH = Highest, second-highest
NA = Not Applicable

[a] Concentrations are based on concentrations predicted using 5 years of meteorological data from 2001 to 2005 of surface and upper air data from the National Weather Service stations at Fort Myers Southwest Florida Regional (RSW) Airport and Tampa International Airport, respectively.

**Table 7-1: $SO_2$ Effects Levels for Various Plant Species**

| Plant Species | Observed Effect Level (µg/m$^3$) | Exposure (Time) | Reference |
|---|---|---|---|
| Sensitive to tolerant | 920 (20 percent displayed visible injury) | 3 hours | McLaughlin and Lee, 1974 |
| Lichens | 200 to 400 | 6 hr/wk for 10 weeks | Hart, et al., 1988 |
| Cypress, slash pine, live oak, mangrove | 1,300 | 8 hours | Woltz and Howe, 1981 |
| Jack pine seedlings | 470-520 | 24 hours | Malhotra and Kahn, 1978 |
| Black oak | 1,310 | Continuously for 1 week | Carlson, 1979 |

**Table 7-2 Sensitivity Groupings of Vegetation Based on Visible Injury at Different $SO_2$ Exposures[a]**

| Sensitivity Grouping | $SO_2$ Concentration | | Plants |
|---|---|---|---|
| | 1-Hour | 3-Hour | |
| Sensitive | 1,310 - 2,620 μg/m$^3$ (0.5 - 1.0 ppm) | 790 - 1,570 μg/m$^3$ (0.3 - 0.6 ppm) | Ragweeds<br>Legumes<br>Blackberry<br>Southern pines<br>Red and black oaks<br>White ash<br>Sumacs |
| Intermediate | 2,620 - 5,240 μg/m$^3$ (1.0 - 2.0 ppm) | 1,570 - 2,100 μg/m$^3$ (0.6 - 0.8 ppm) | Maples<br>Locust<br>Sweetgum<br>Cherry<br>Elms<br>Tuliptree<br>Many crop and garden species |
| Resistant | >5,240 μg/m$^3$ (>2.0 ppm) | >2,100 μg/m$^3$ (>0.8 ppm) | White oaks<br>Potato<br>Upland cotton<br>Corn<br>Dogwood<br>Peach |

[a] Based on observations over a 20-year period of visible injury occurring on over 120 species growing in the vicinities of coal-fired power plants in the southeastern United States.

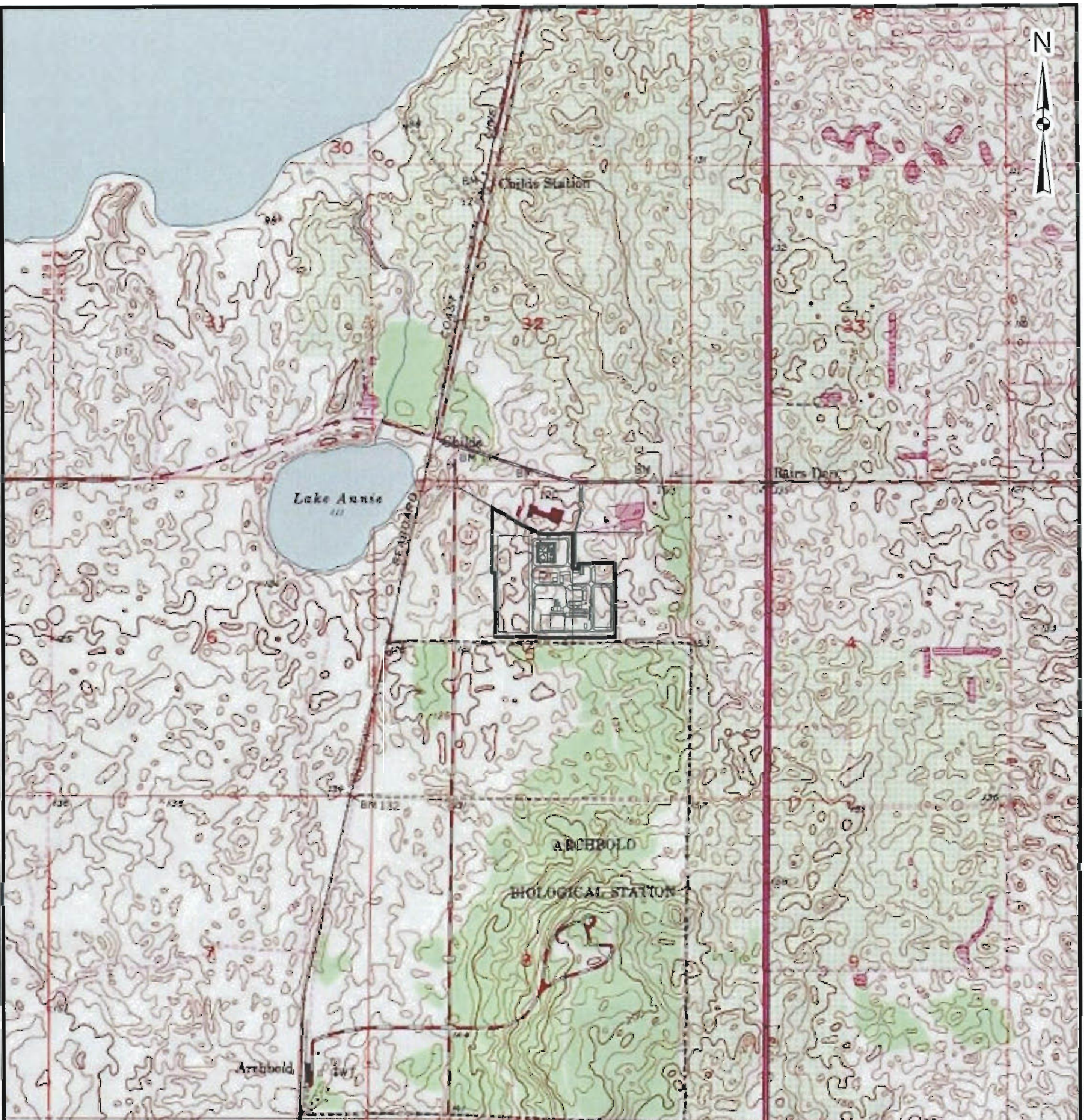
Source: EPA, 1982a.

**Table 7-3: Examples of Reported Effects of Air Pollutants at Concentrations Below National Secondary AAQS**

| Pollutant | Reported Effect | Concentration ($\mu g/m^3$) | Exposure |
|---|---|---|---|
| Sulfur Dioxide[a] | Respiratory stress in guinea pigs | 427 to 854 | 1 hour |
| | Respiratory stress in rats | 267 | 7 hours/day; 5 day/week for 10 weeks |
| | Decreased abundance in deer mice | 13 to 157 | continually for 5 months |
| Nitrogen Dioxide[b,c] | Respiratory stress in mice | 1,917 | 3 hours |
| | Respiratory stress in guinea pigs | 96 to 958 | 8 hours/day for 122 days |
| Particulates[a] | Respiratory stress, reduced respiratory disease defenses | 120 $PbO_3$ | continually for 2 months |
| | Decreased respiratory disease defenses in rats, same with hamsters | 100 $NiCl_2$ | 2 hours |

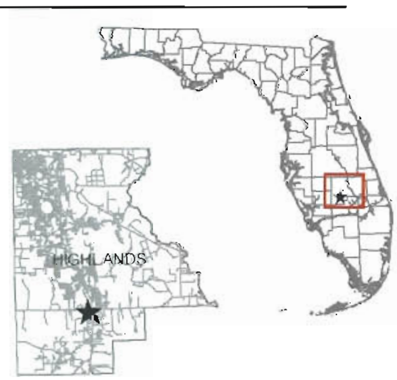
Sources: [a] Newman and Schreiber, 1988.
[b] Gardner and Graham, 1976.
[c] Trzeciak et al., 1977.

# FIGURES




## LEGEND

Ethanol Plant Site




## REFERENCES

1. Ethanol Plant Site, Highlands Envirofuels, LLC., 2011.

| | | | | | | |
|---|---|---|---|---|---|---|
| 2 | 6/23/11 | DES | Updated Title Block | NRL | PT | DB |
| 1 | 4/26/11 | DES | Added Facility Layout | NRL | PT | DB |

PROJECT

HIGHLANDS ENVIROFUELS, LLC

TITLE

**ADVANCED BIOFUEL ETHANOL BIOREFINERY LOCATION MAP**

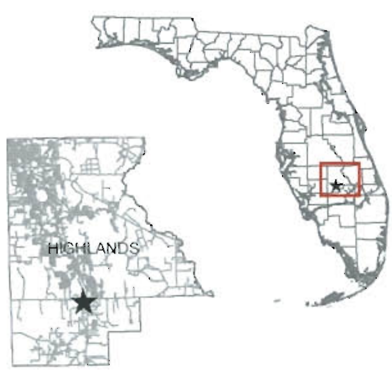
Golder Associates
Gainesville, Florida

| | | | | |
|---|---|---|---|---|
| PROJECT No. | | 10387668 | FILE No. 10387668_A001 | |
| DESIGN | PT | 2/22/2011 | SCALE: AS SHOWN | REV. 1 |
| GIS | NRL | 2/28/2011 | **FIGURE 1-1** | |
| CHECK | PT | 4/26/2011 | | |
| REVIEW | DB | 4/26/2011 | | |

Map Document: TB-PS-A.mxt / Modified 3/15/2010 5:11:02 PM / Plotted 3/16/2010 3:12:54 PM by rlamar


## LEGEND

Ethanol Plant Site




## REFERENCES

1 Ethanol Plant Site, Highlands Envirofuels, LLC., 2011.

2 200 0 Feet

| | | | | | | |
|---|---|---|---|---|---|---|
| 2 | 5/23/11 | DES | Updated Title Block | NRL | PT | DB |
| 1 | 4/26/11 | DES | Added Facility Layout | NRL | PT | DB |

PROJECT

HIGHLANDS ENVIROFUELS, LLC

TITLE

**ADVANCED BIOFUEL ETHANOL BIOREFINERY AERIAL LOCATION MAP**

Golder Associates
Gainesville, Florida

| | | | | |
|---|---|---|---|---|
| PROJECT No. | | 10387668 | FILE No. | 10387668_A002 |
| DESIGN | PT | 2/22/2011 | SCALE: AS SHOWN | REV. 1 |
| GIS | NRL | 2/28/2011 | **FIGURE 2-1** | |
| CHECK | PT | 4/26/2011 | | |
| REVIEW | DB | 4/26/2011 | | |

Map Document: TB-PS-A.mxt / Modified 3/15/2010 5:11:02 PM / Plotted 3/16/2010 3:12:54 PM by rlamar


## LEGEND

- ROADS
- SITE BUILDINGS
- SITE CONVEYORS
- SITE FUTURE
- RAIL
- RAIL - EXISTING
- ROAD - EXISTING
- PARCEL 1
- PARCEL 2

2 - TRAILER PARKING
3 - GARAGE
4 - CANE TABLES
5 - COLLECTING CONVEYOR
6 - TRANSFER CONVEYOR TO DIFFUSER
7 - DIFFUSER
8 - BAGASSE STORAGE
9 - BAGASSE CONVEYOR TO BOILER AND STORAGE
10 - BAGASSE STORAGE DISTRIBUTION CONVEYOR
11 - BAGASSE RECLAIM PIT CONVEYOR
14 - BOILER
15 - TURBINE GENERATOR
16 - BOILER EMISSIONS CONTROL EQUIPMENT
17 - FUTURE BOILER
18 - FUTURE TURBINE GENERATOR
19 - FUTURE BOILER EMMISSIONS CONTROL EQUIPMENT
20 - BOILER STACK
21 - COOLING TOWER
22 - WEAK JUICE TANK
23 - CONCENTRATED JUICE TANK
24 - VINASSE TANK
25 - CONCENTRATED VINASSE TANK
26 - CONCENTRATED VINASSE LOADOUT AREA
27 - EVAPORATORS
28 - FERMENTATION
29 - BEERWELL TANK
30 - DISTILLATION
31 - MAINTENANCE BUILDING
32 - STOREROOM
33 - ASH SILO
34 - ASH SILO CONVEYOR #1
35 - ASH SILO CONVEYOR #2
36 - FUEL ETHANOL TANK
37 - FUTURE FUEL ETHANOL TANK
38 - 200 PROOF TANK
39 - OFF SPEC TANK
40 - GASOLINE TANK
41 - CORROSION INHIBITOR TANK
42 - ETHANOL TRUCK / RAIL LOADOUT AREA
43 - OFFICE / LAB BUILDING
44 - OFFICE / LAB PARKING

## REFERENCES


1. Ethanol Plant Site, Facility Layout, Highlands Envirofuels, LLC., 2011.


350 0 Feet

| | | | | | | |
|---|---|---|---|---|---|---|
| 2 | 5/23/11 | DES | Updated Title Block | NRL | PT | DB |
| 1 | 4/26/11 | DES | Added Facility Layout | NRL | PT | DB |

PROJECT

HIGHLANDS ENVIROFUELS, LLC

TITLE

# ADVANCED BIOFUEL ETHANOL BIOREFINERY PLOT PLAN

Golder Associates
Gainesville, Florida

| | | | | |
|---|---|---|---|---|
| PROJECT No. | | 10387668 | FILE No. | 10387668_A003 |
| DESIGN | PT | 2/22/2011 | SCALE: AS SHOWN | REV. 1 |
| GIS | NRL | 2/28/2011 | FIGURE 2-2 | |
| CHECK | PT | 4/26/2011 | | |
| REVIEW | DB | 4/26/2011 | | |

Map Document: TB-PS-A.mxd / Modified 3/15/2010 5:11:02 PM / Plotted 3/16/2010 3:12:54 PM by rlamar

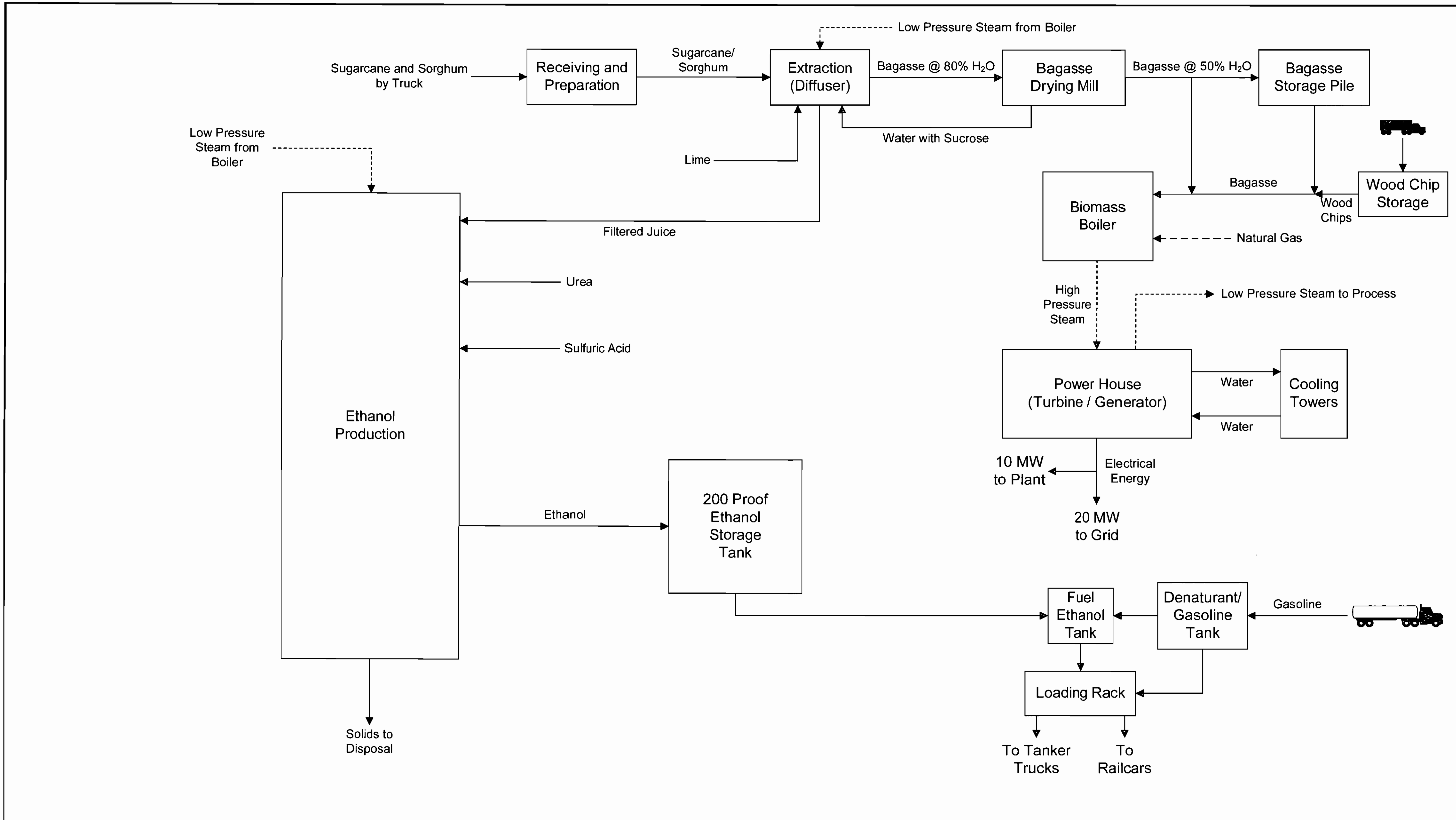



Figure 2-3
Facility Process Flow Diagram
Highlands EnviroFuels, LLC

Source: Golder Associates, 2011.

**Process Flow Legend**
Solid/Liquid
Gas
Steam

Golder Associates

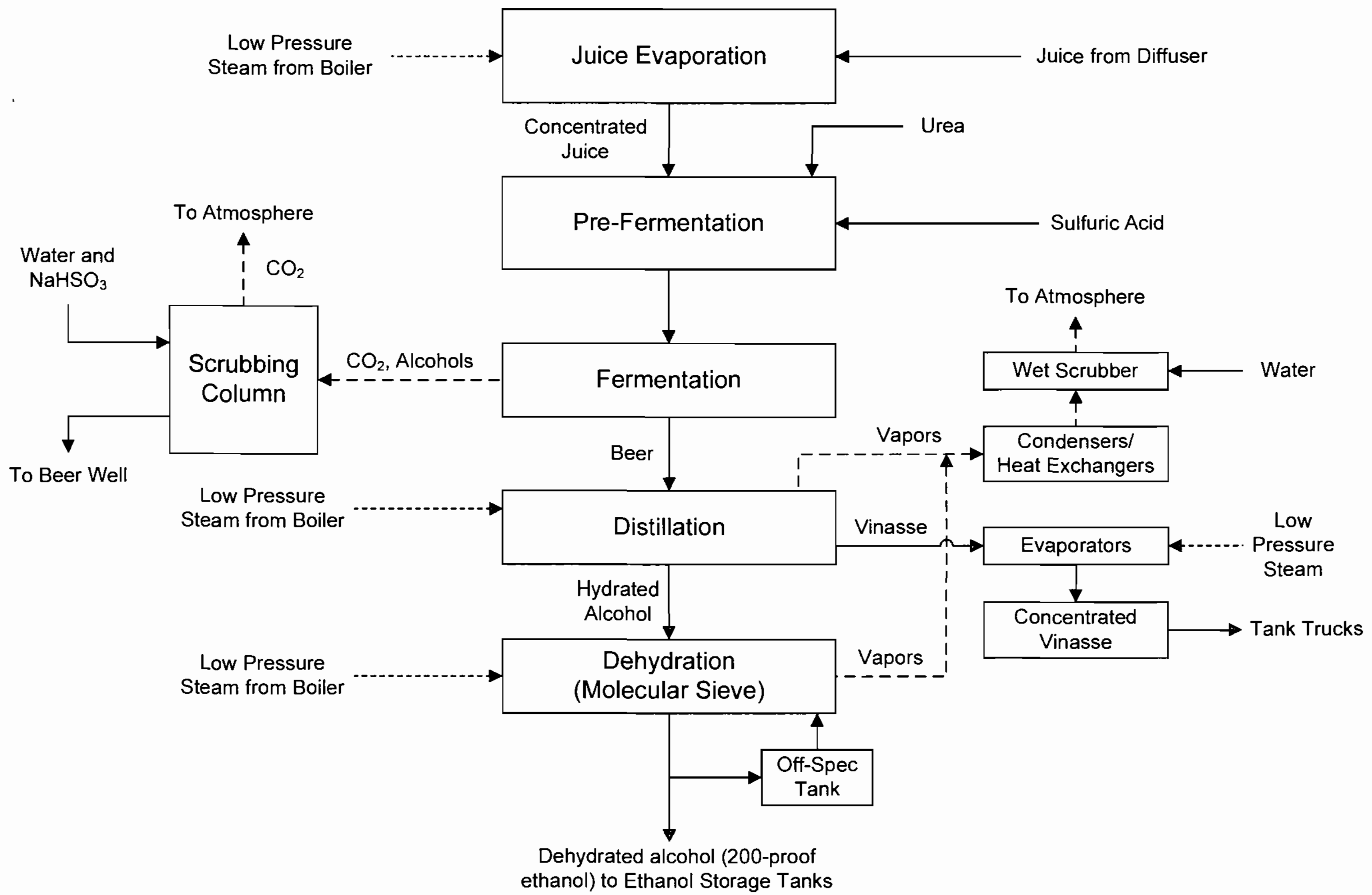



Figure 2-4
Ethanol Production Process Flow Diagram
Highlands EnviroFuels, LLC

Source: Golder Associates, 2011.

**Process Flow Legend**

| | |
|---|---|
| Solid/Liquid | ——→ |
| Gas | – – –→ |
| Steam | ------→ |

Golder Associates

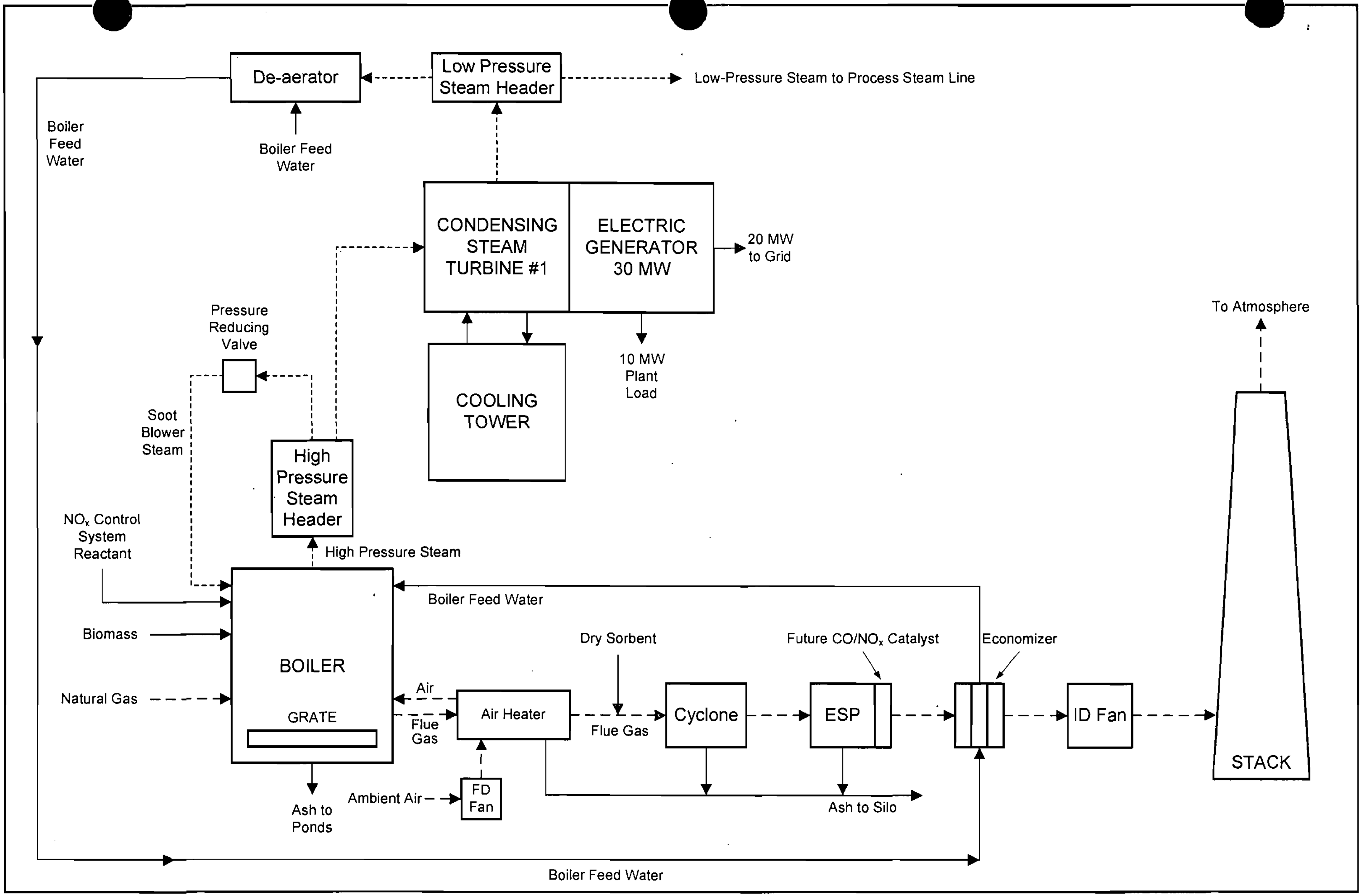



Figure 2-5
Boiler Process Flow Diagram
Highlands EnviroFuels, LLC

Sources: Fagen, Golder; 2011.

**Process Flow Legend**
Solid/Liquid
Gas
Steam

Golder Associates

FIGURE 2-6

GENERAL ARRANGEMENT PLAN OF
BAGASSE-FIRED BOILER

CONFIDENTIAL BUSINESS INFORMATION
SUBMITTED UNDER SEPARATE COVER

FIGURE 2-7

ELEVATION VIEW OF
BAGASSE-FIRED BOILER

CONFIDENTIAL BUSINESS INFORMATION
SUBMITTED UNDER SEPARATE COVER

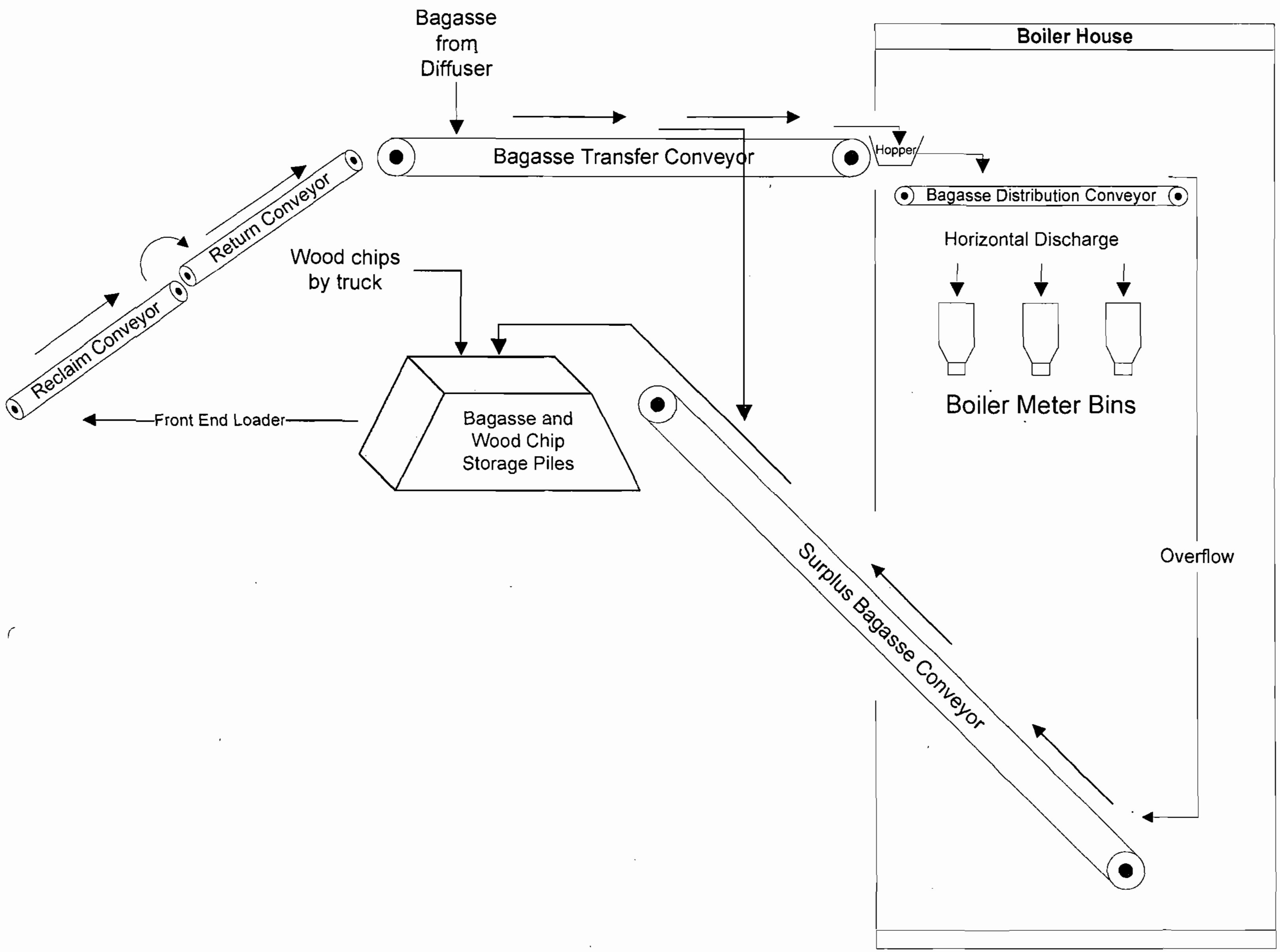



Figure 2-8
Biomass Handling System for Boiler
Highlands EnviroFuels, LLC
Sources: Fagen, Golder; 2011.

**Legend**

Bagasse
Gas Flow

Golder Associates

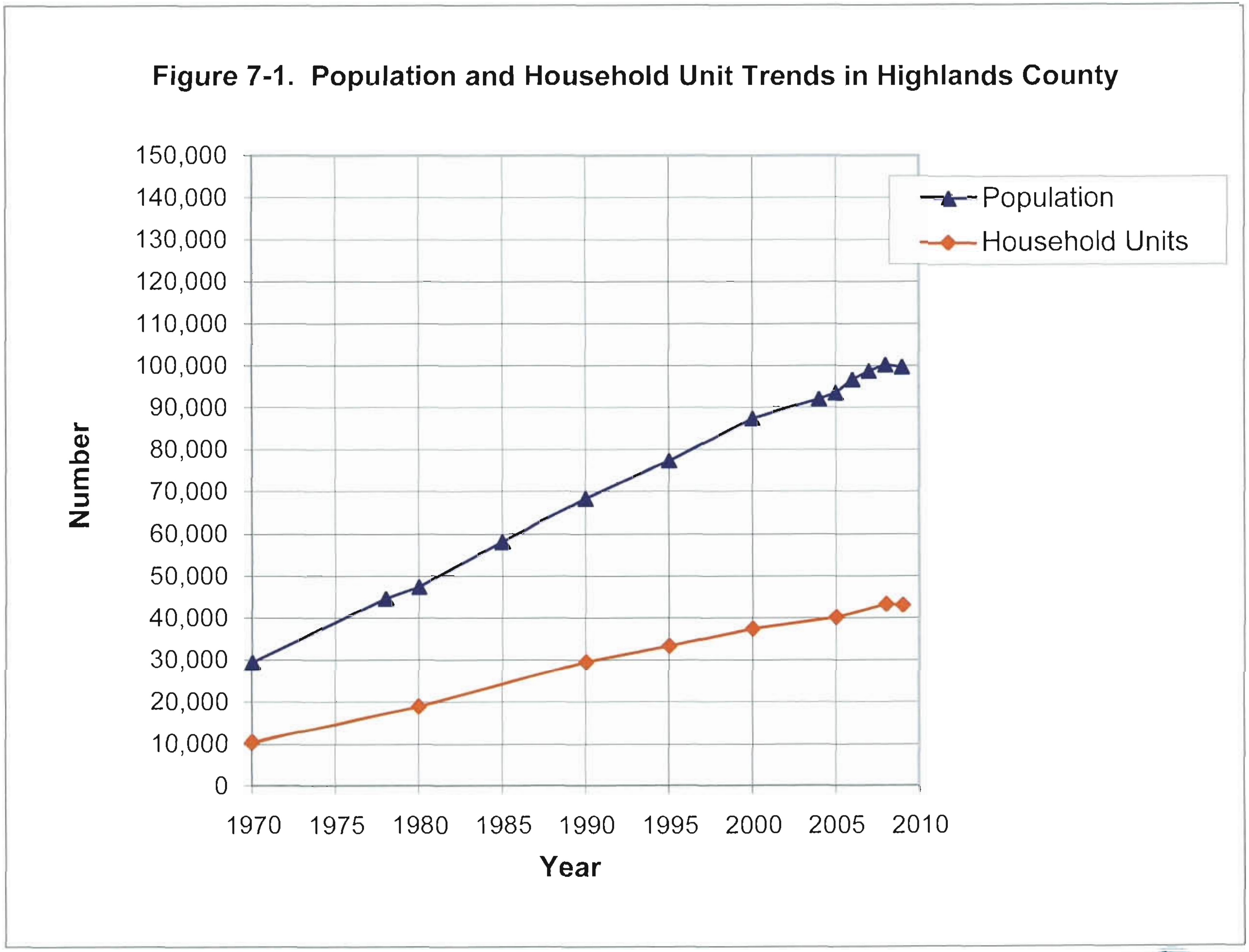


Figure 7-1. Population and Household Unit Trends in Highlands County
150,000
140,000
130,000
120,000
110,000
100,000
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
Number
1970
1975
1980
1985
1990
1995
2000
2005
2010
Year
Population
Household Units

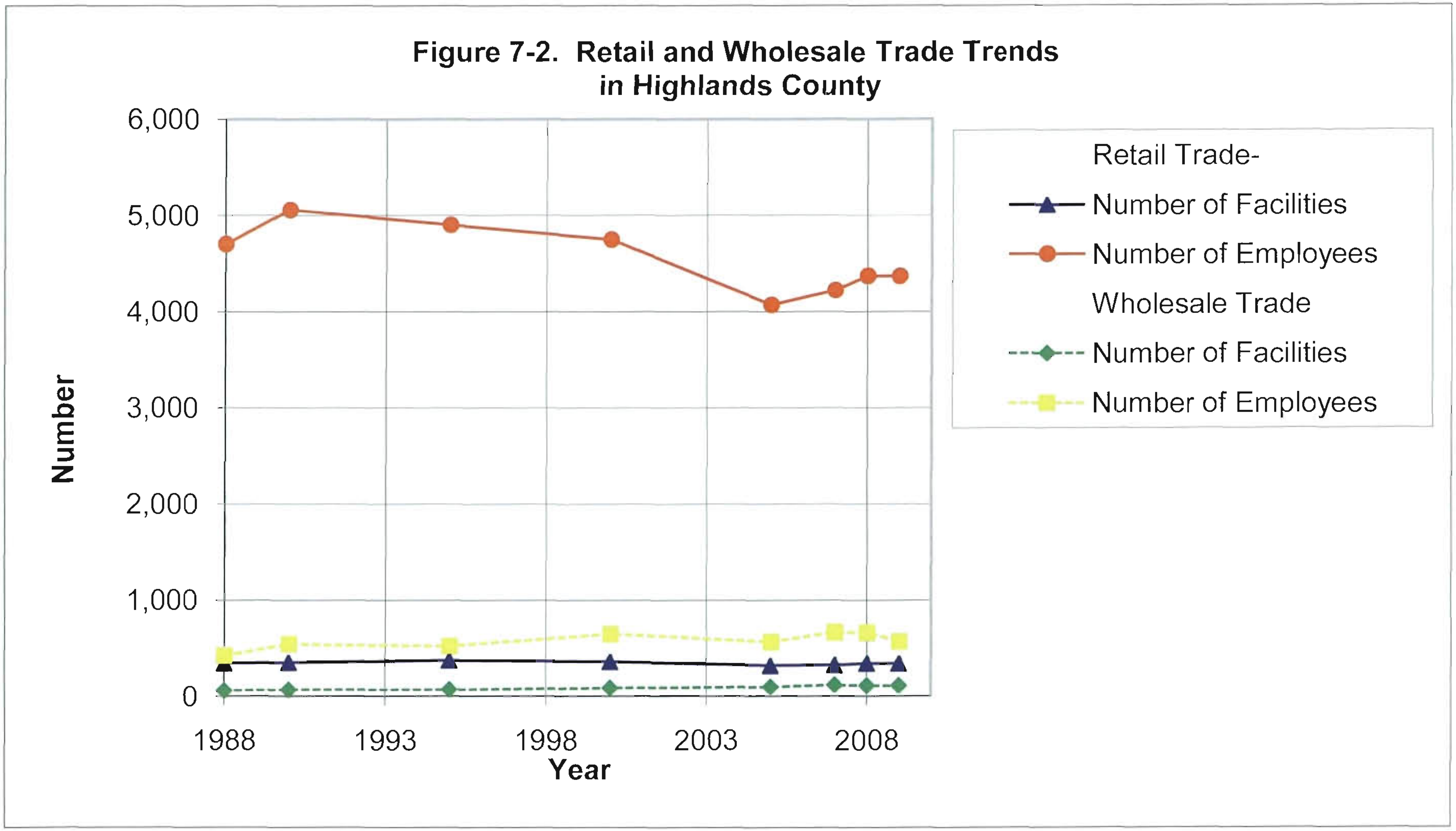
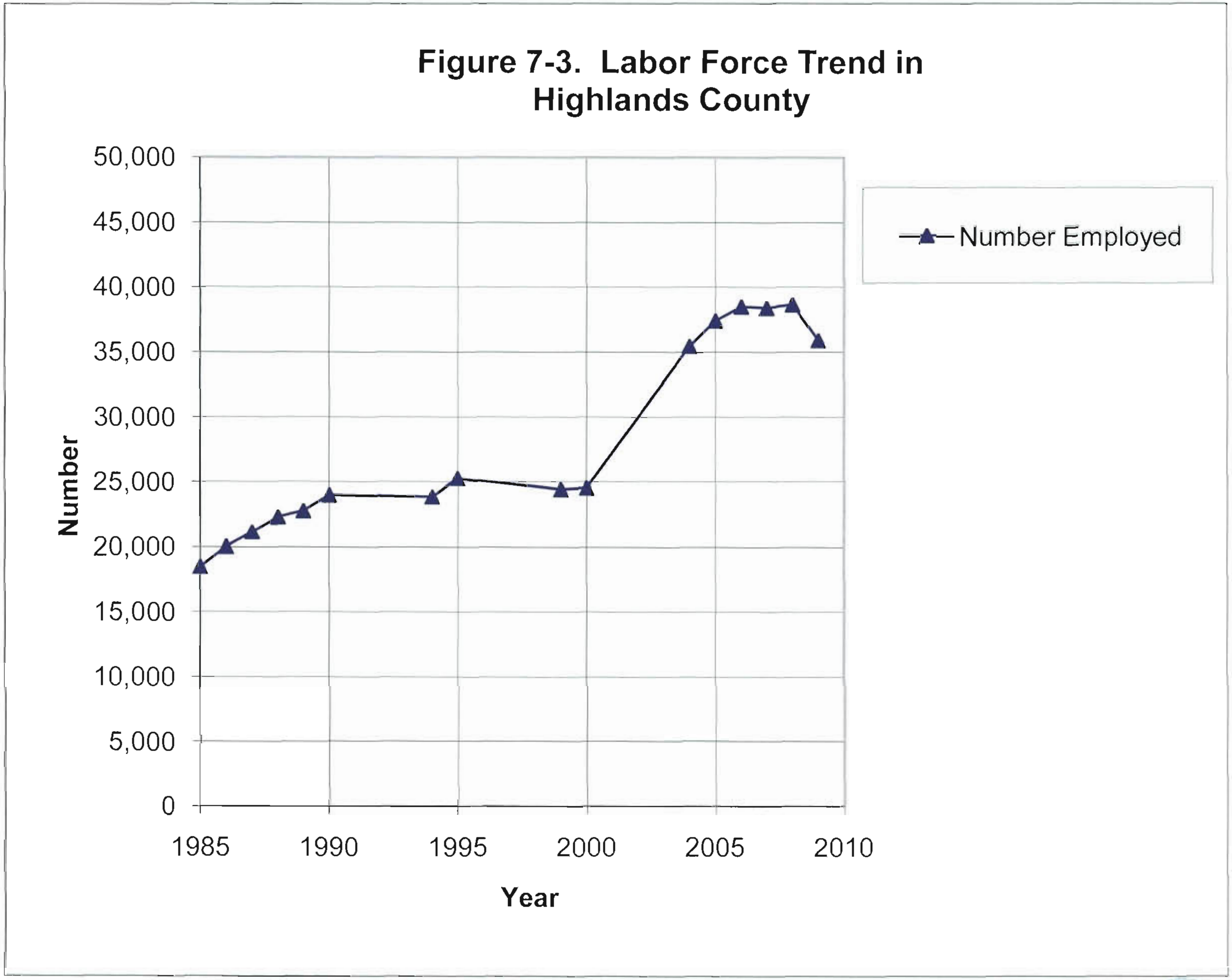


Figure 7-2. Retail and Wholesale Trade Trends
in Highlands County
6,000
5,000
4,000
3,000
2,000
1,000
0
Number
1988
1993
1998
2003
2008
Year
Retail Trade-
Number of Facilities
Number of Employees
Wholesale Trade
Number of Facilities
Number of Employees






Golder Associates

# Figure 7-4. Hotel and Motel Trends in Highlands County

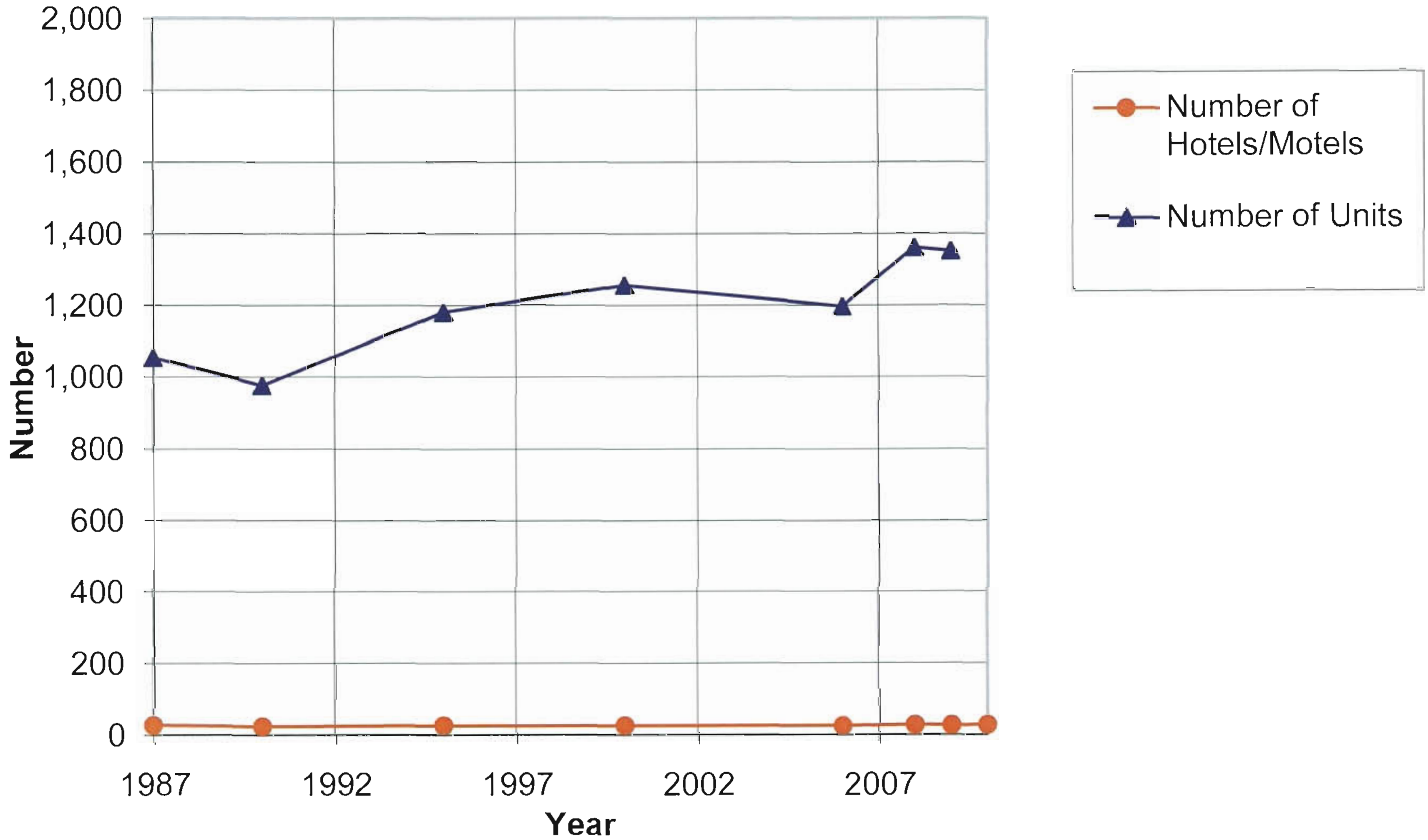


Figure 7-5. Daily Vehicle Miles Traveled (VMT) Estimates for Motor Vehicles for Highlands County

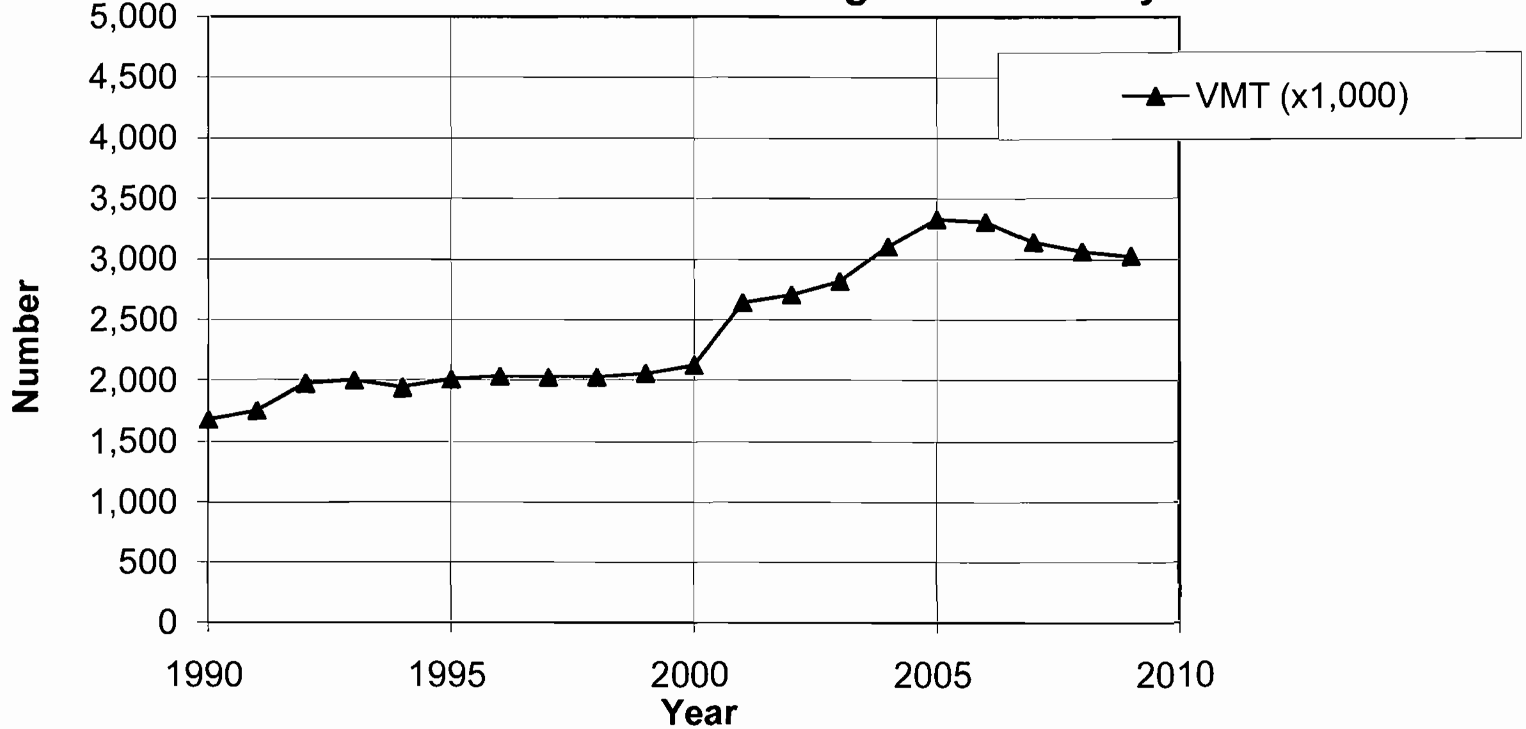


**Figure 7-6. Manufacturing and Agriculture Trends in Highlands County**

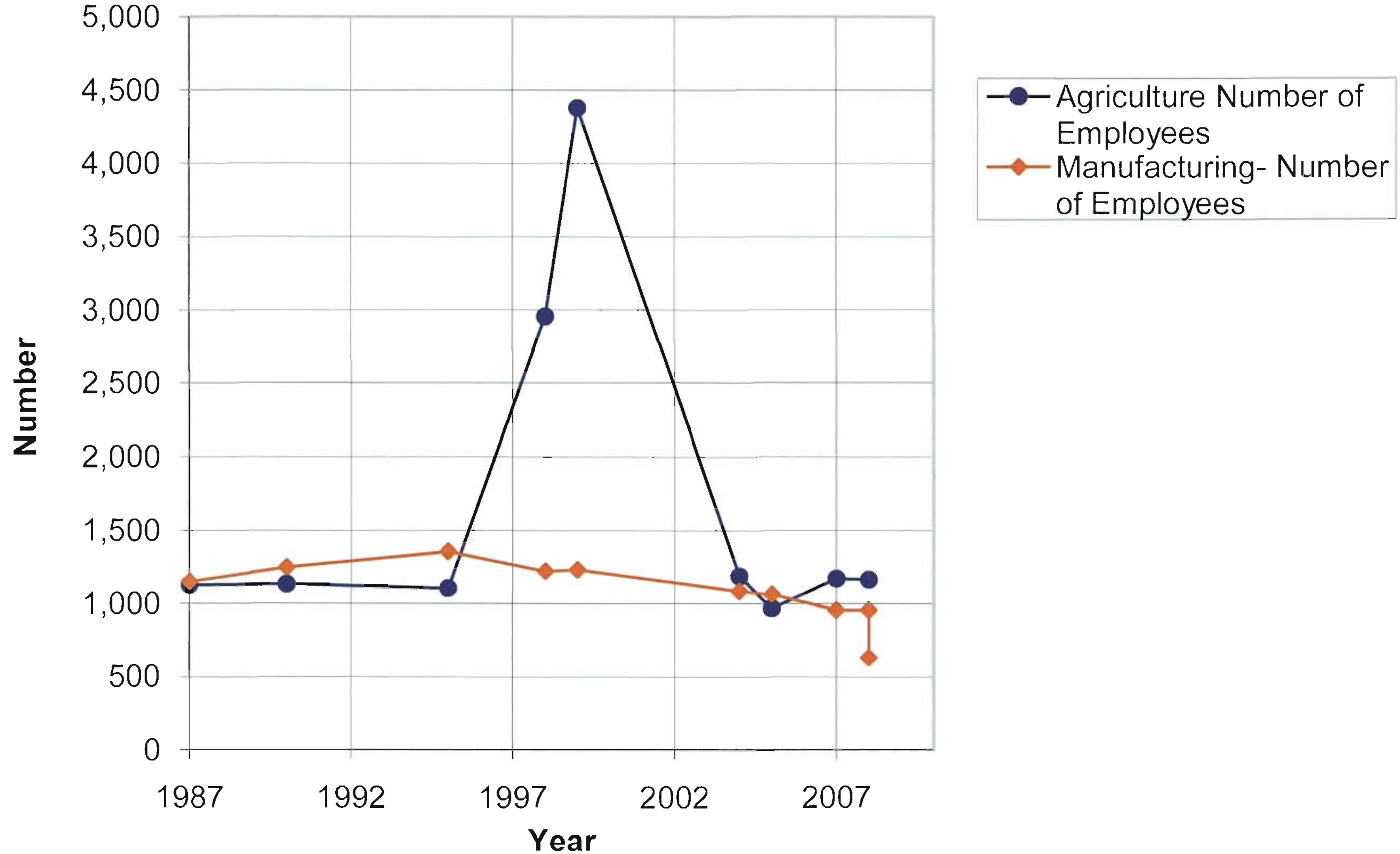


Figure 7-7. Electrical Power Generation Capacity in Highlands County

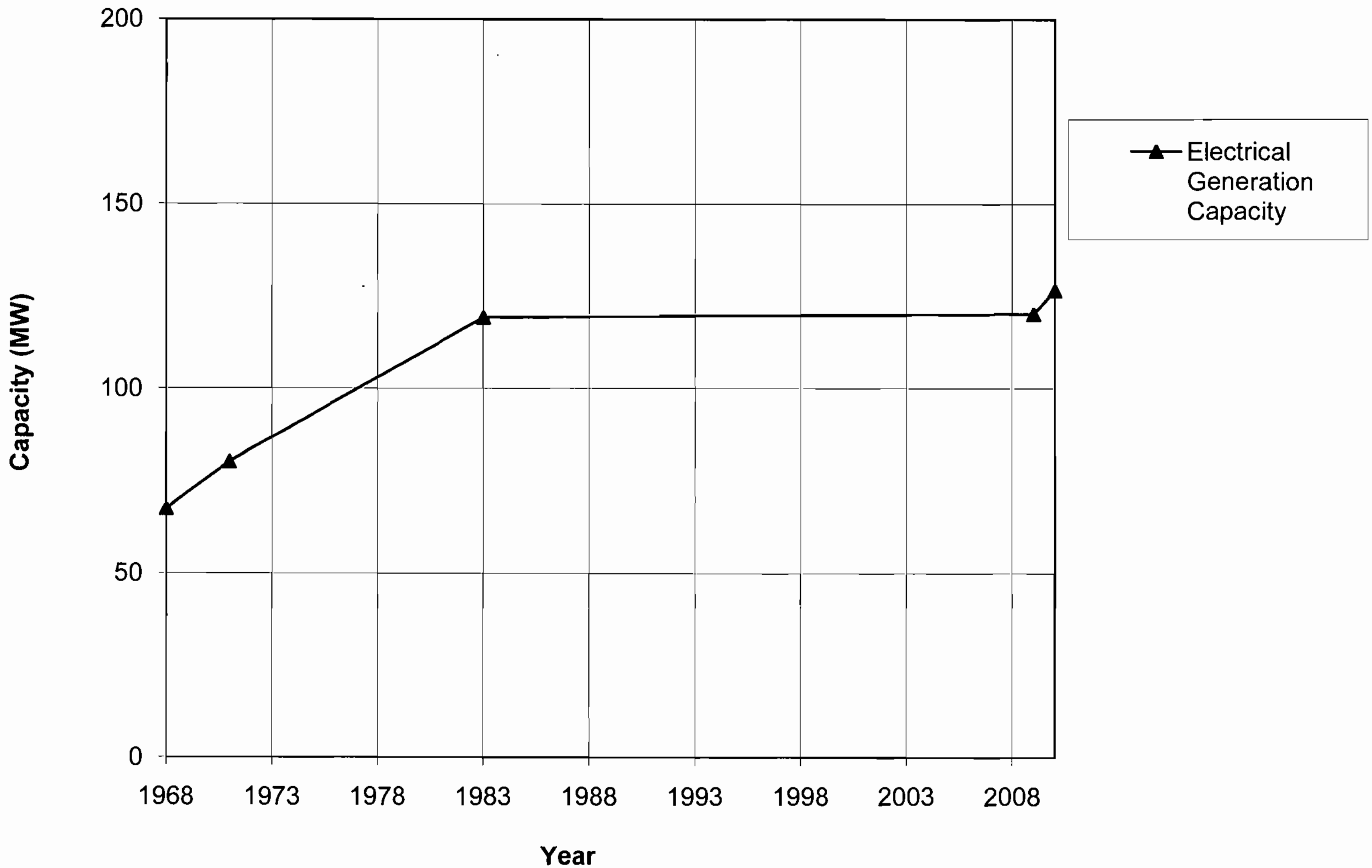
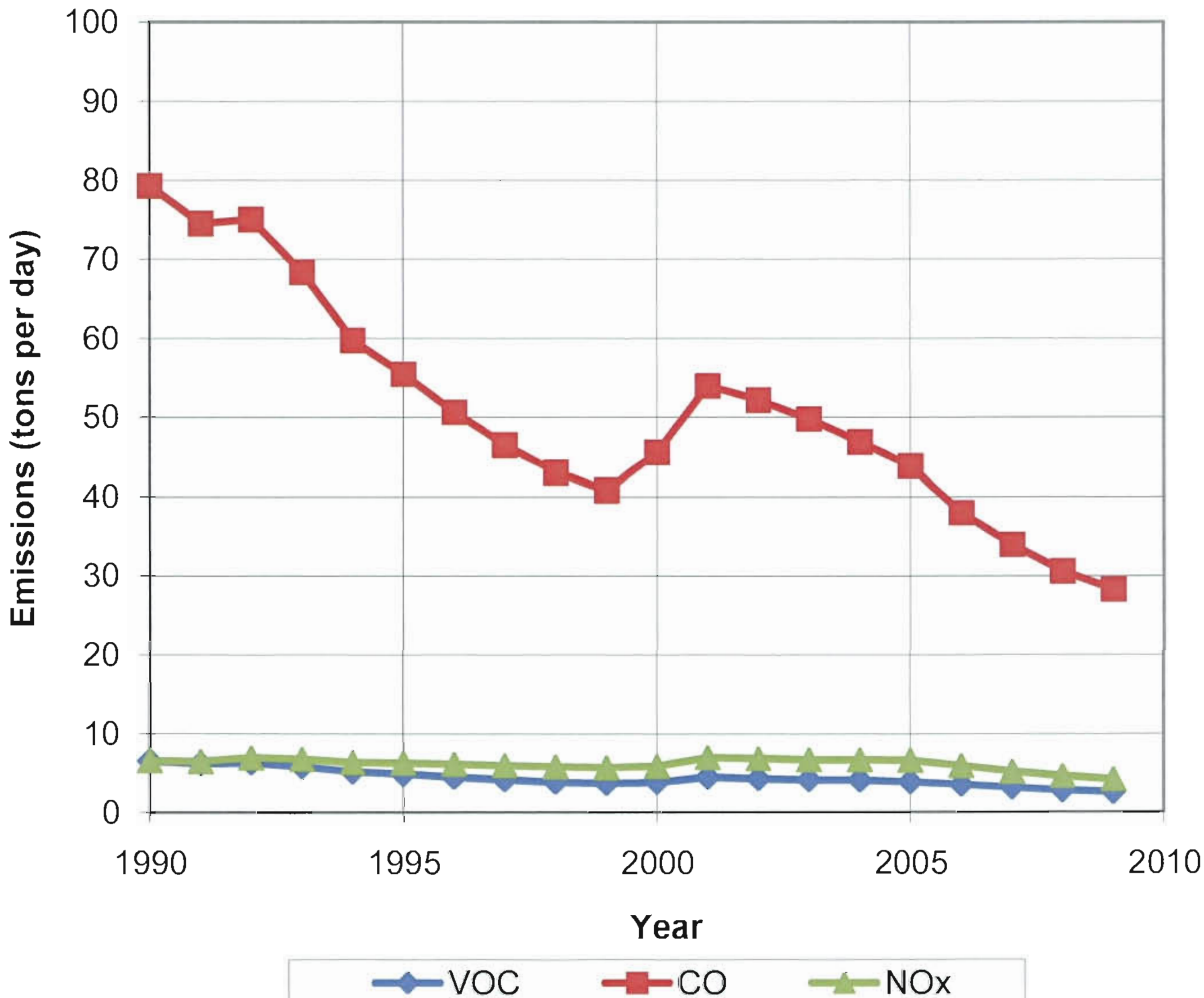


**Figure 7-8. Mobile Source Emissions (Tons per Day) of CO, VOC, and $NO_x$, in Highlands County**



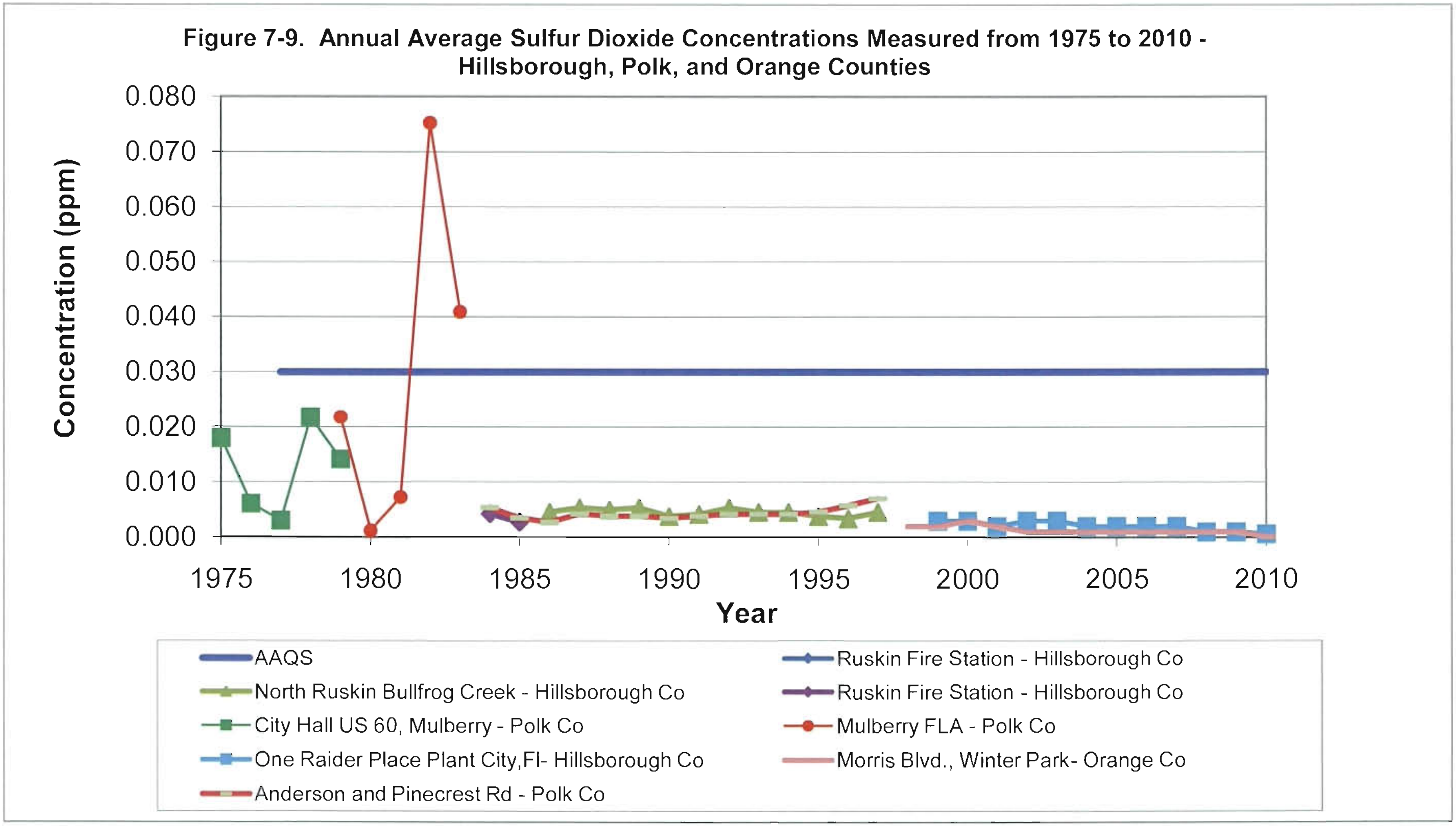


Figure 7-9. Annual Average Sulfur Dioxide Concentrations Measured from 1975 to 2010 - Hillsborough, Polk, and Orange Counties
0.080
0.070
0.060
0.050
0.040
0.030
0.020
0.010
0.000
Concentration (ppm)
1975
1980
1985
1990
1995
2000
2005
2010
Year
AAQS
Ruskin Fire Station - Hillsborough Co
North Ruskin Bullfrog Creek - Hillsborough Co
Ruskin Fire Station - Hillsborough Co
City Hall US 60, Mulberry - Polk Co
Mulberry FLA - Polk Co
One Raider Place Plant City,Fl- Hillsborough Co
Morris Blvd., Winter Park- Orange Co
Anderson and Pinecrest Rd - Polk Co

Figure 7-10. 24-hour Average Sulfur Dioxide Concentrations (2nd Highest Values) Measured from 1975 to 2010 - Hillsborough, Polk, and Orange Counties

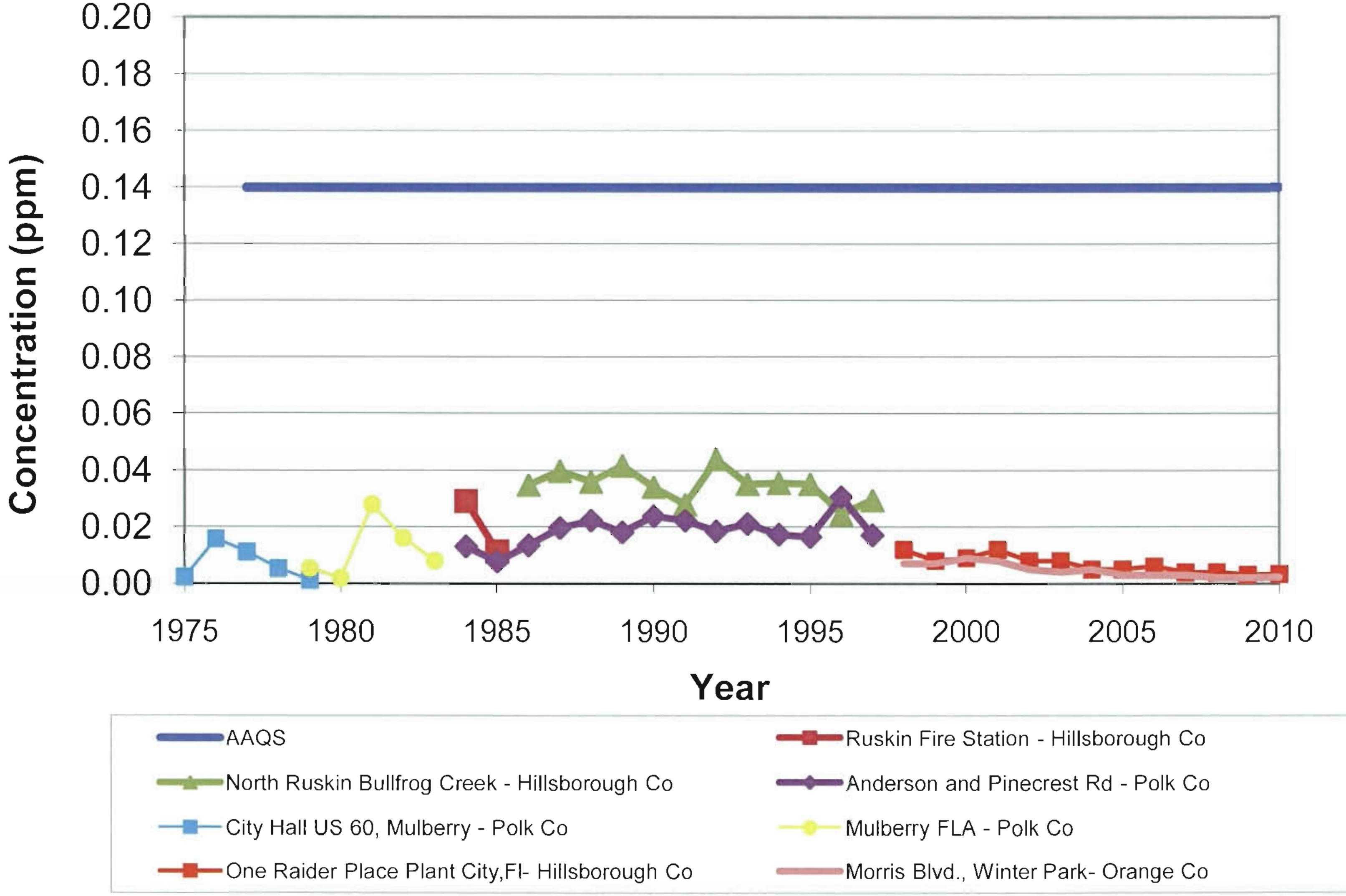


**Figure 7-11. 3-Hour Average Sulfur Dioxide Concentrations (2nd Highest Values) Measured from 1986 to 2010 - Hillsborough, Polk, and Orange Counties**

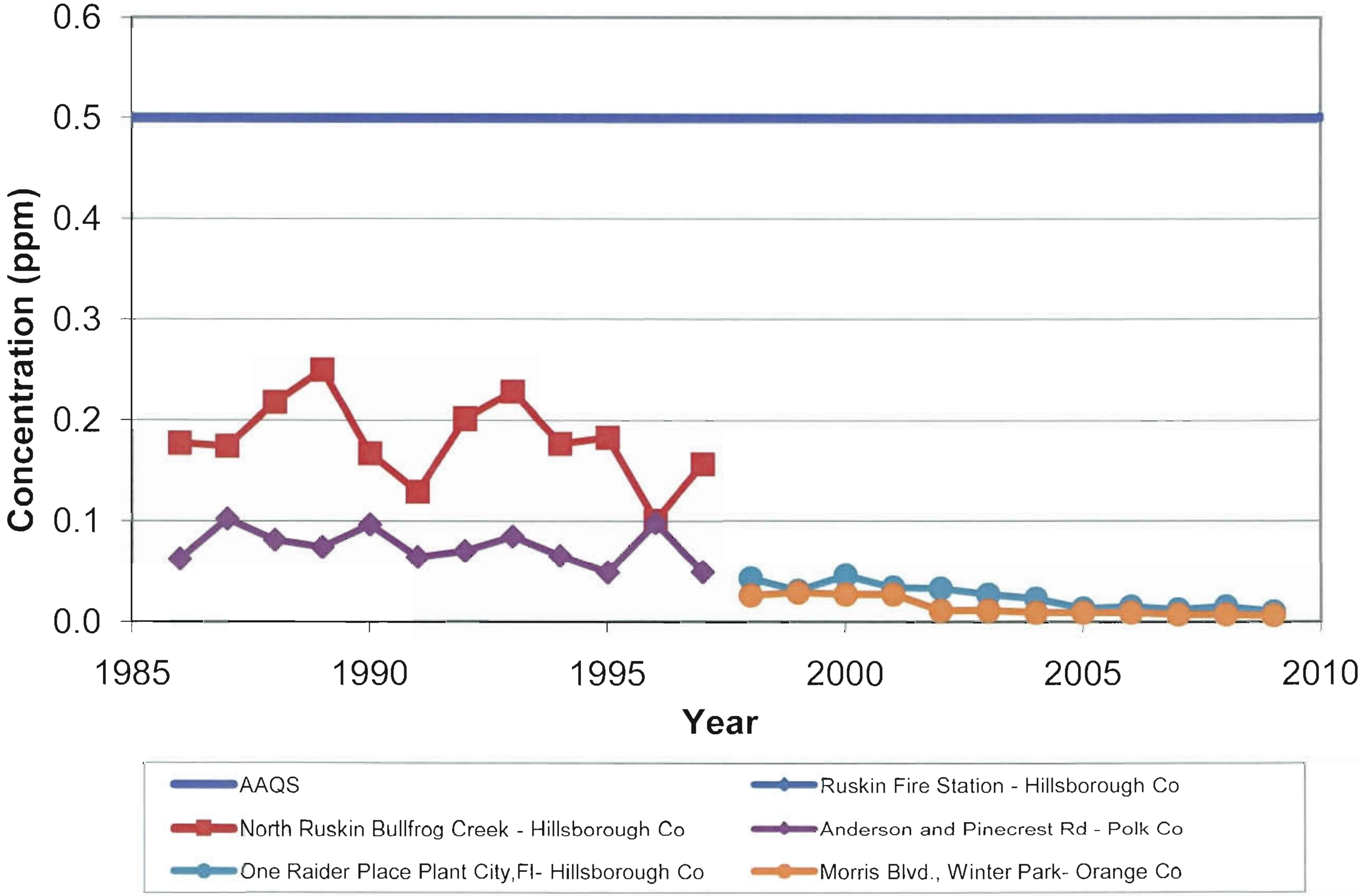
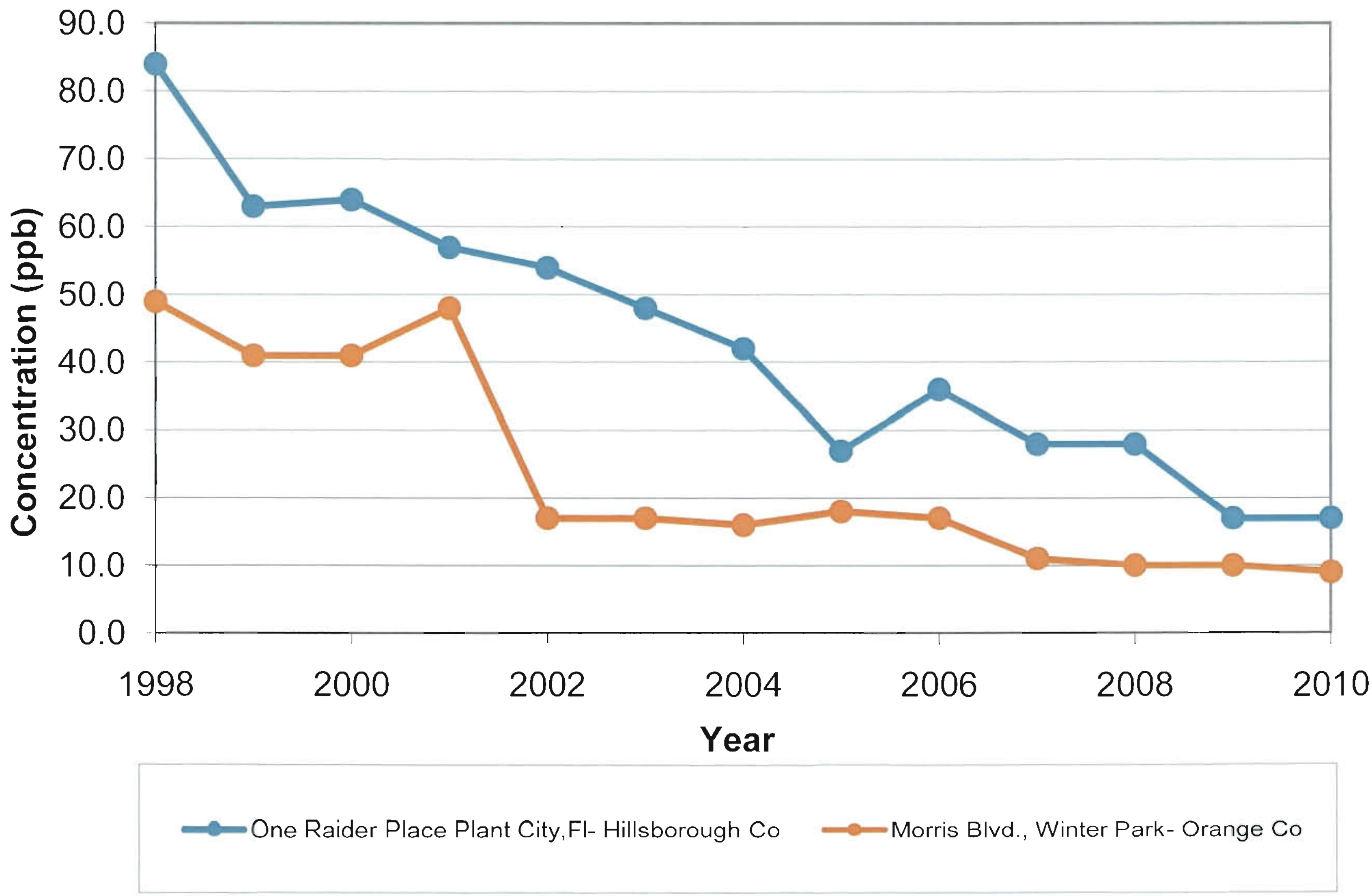


Figure 7-12a. 1-Hour Average Sulfur Dioxide Concentrations (2nd Highest Values) Measured from 1998 to 2010 - Hillsborough, Polk, and Orange Counties



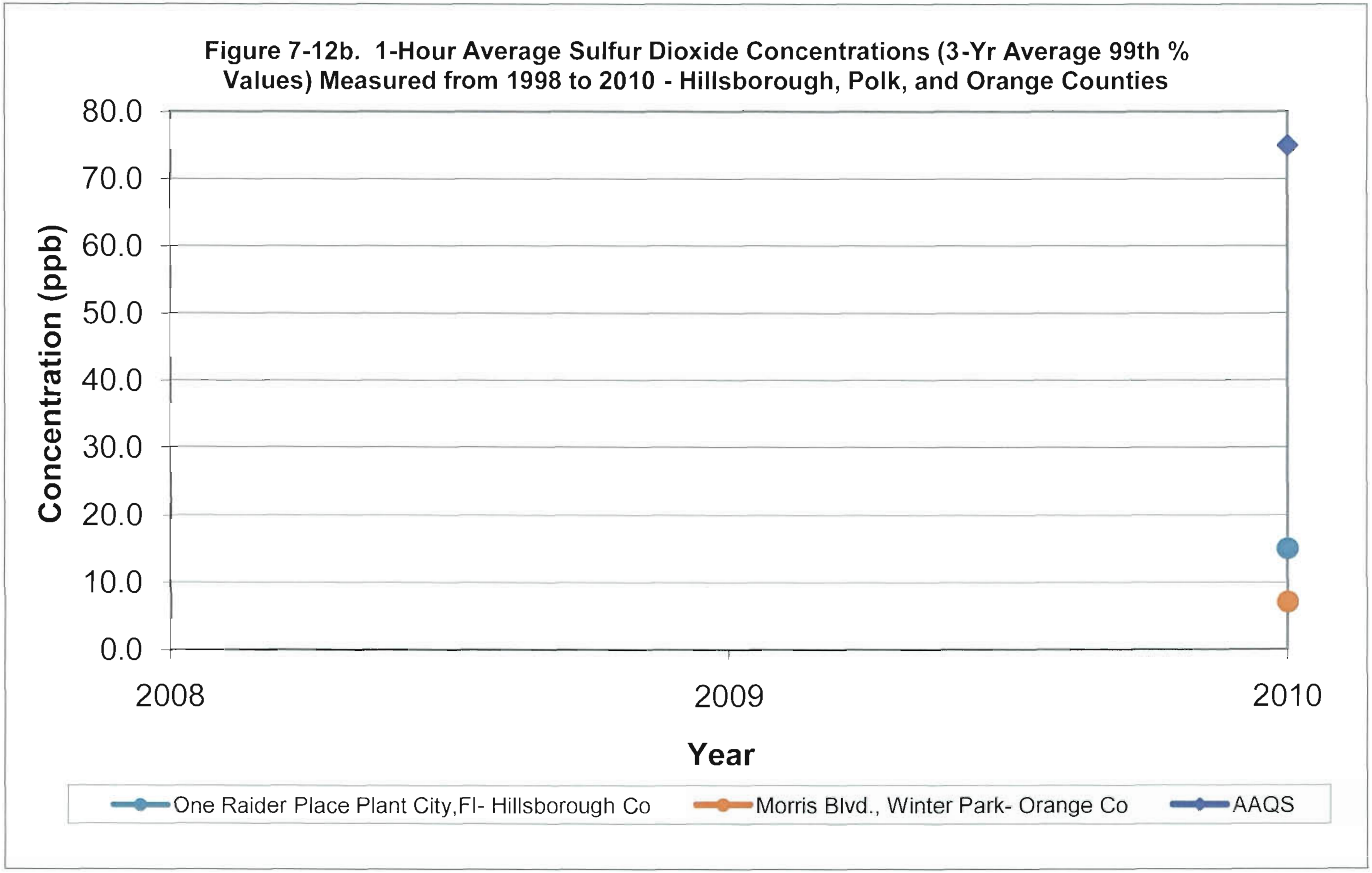
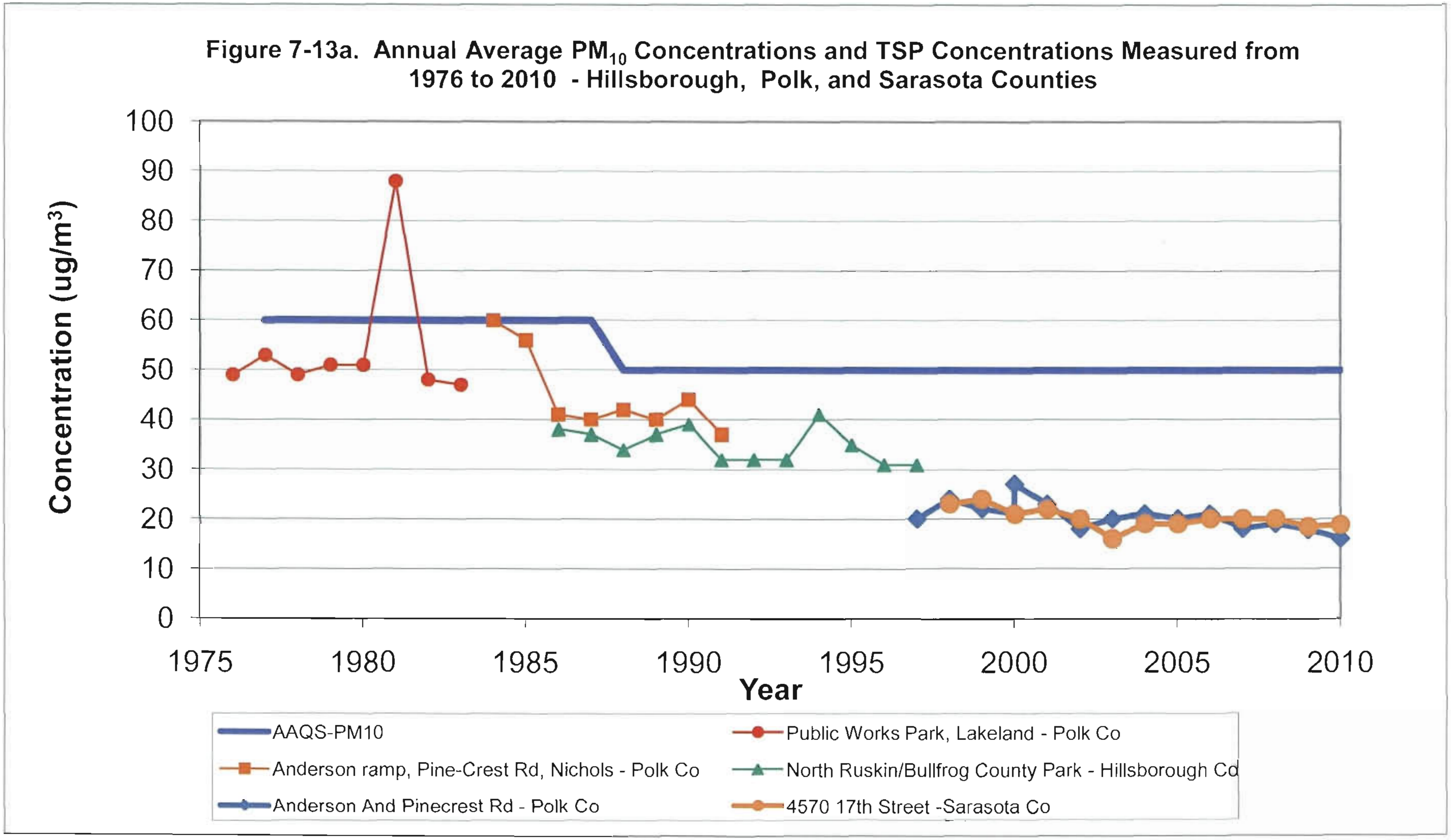


Figure 7-12b. 1-Hour Average Sulfur Dioxide Concentrations (3-Yr Average 99th % Values) Measured from 1998 to 2010 - Hillsborough, Polk, and Orange Counties
80.0
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
Concentration (ppb)
2008
2009
2010
Year
One Raider Place Plant City,Fl- Hillsborough Co
Morris Blvd., Winter Park- Orange Co
AAQS



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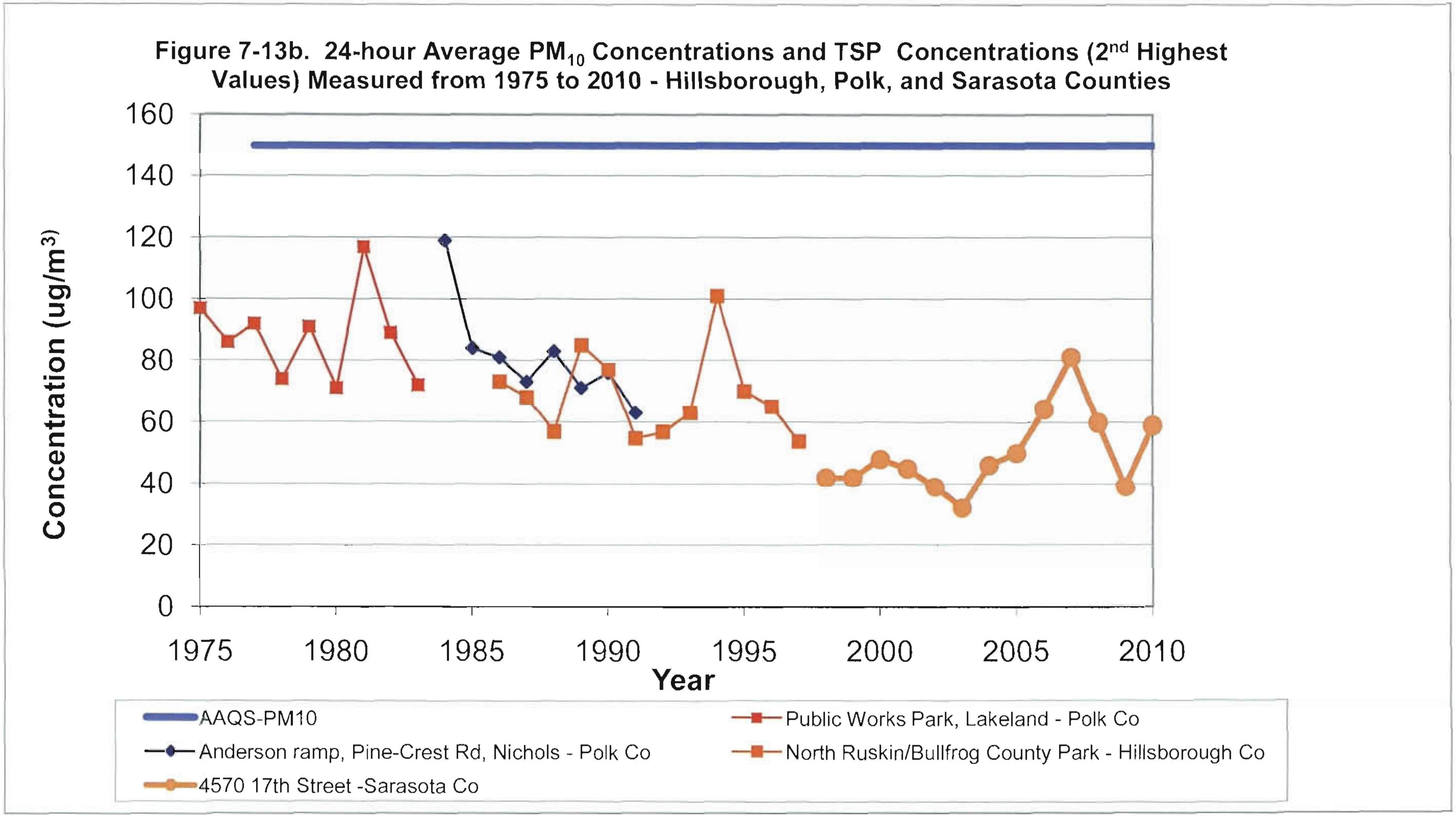
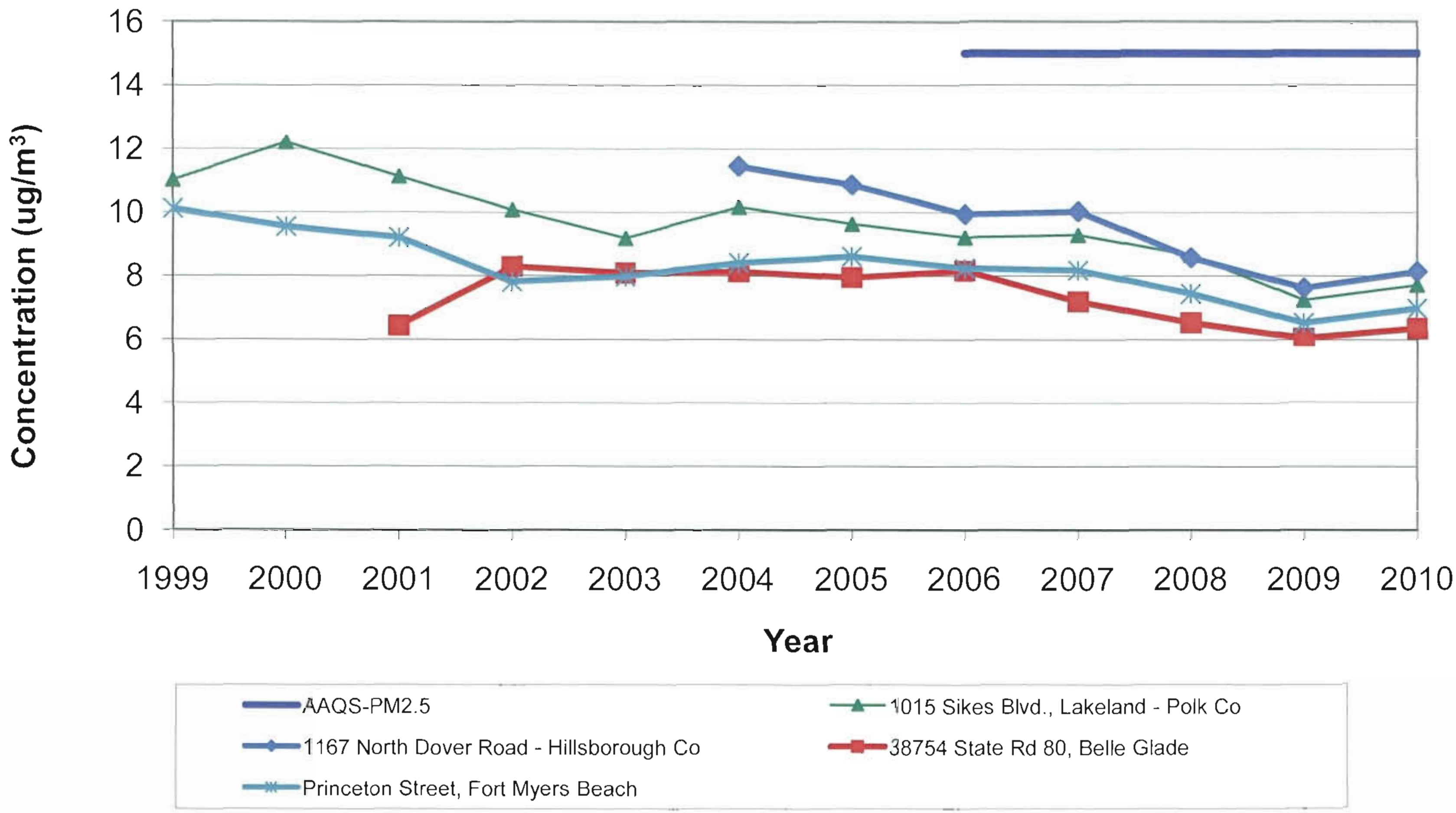


Figure 7-13b. 24-hour Average $PM_{10}$ Concentrations and TSP Concentrations (2nd Highest Values) Measured from 1975 to 2010 - Hillsborough, Polk, and Sarasota Counties
160
140
120
100
80
60
40
20
0
Concentration (ug/m3)
1975
1980
1985
1990
1995
2000
2005
2010
Year
AAQS-PM10
Public Works Park, Lakeland - Polk Co
Anderson ramp, Pine-Crest Rd, Nichols - Polk Co
North Ruskin/Bullfrog County Park - Hillsborough Co
4570 17th Street -Sarasota Co

**Figure 7-14a. Annual Average $PM_{2.5}$ Concentrations Measured from 1999 to 2010 - Hillsborough, Polk, Belle Glade, and Lee Counties**



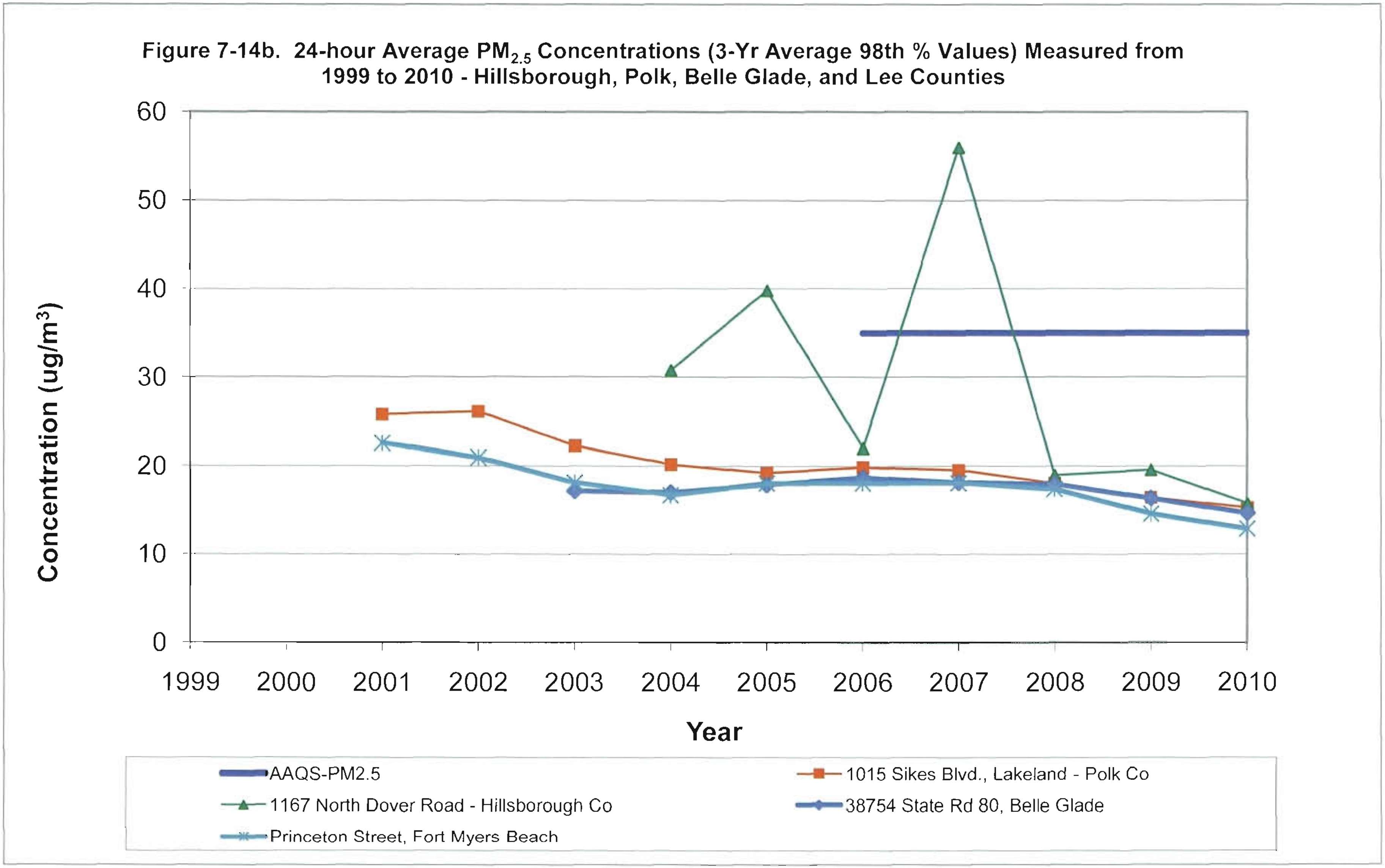





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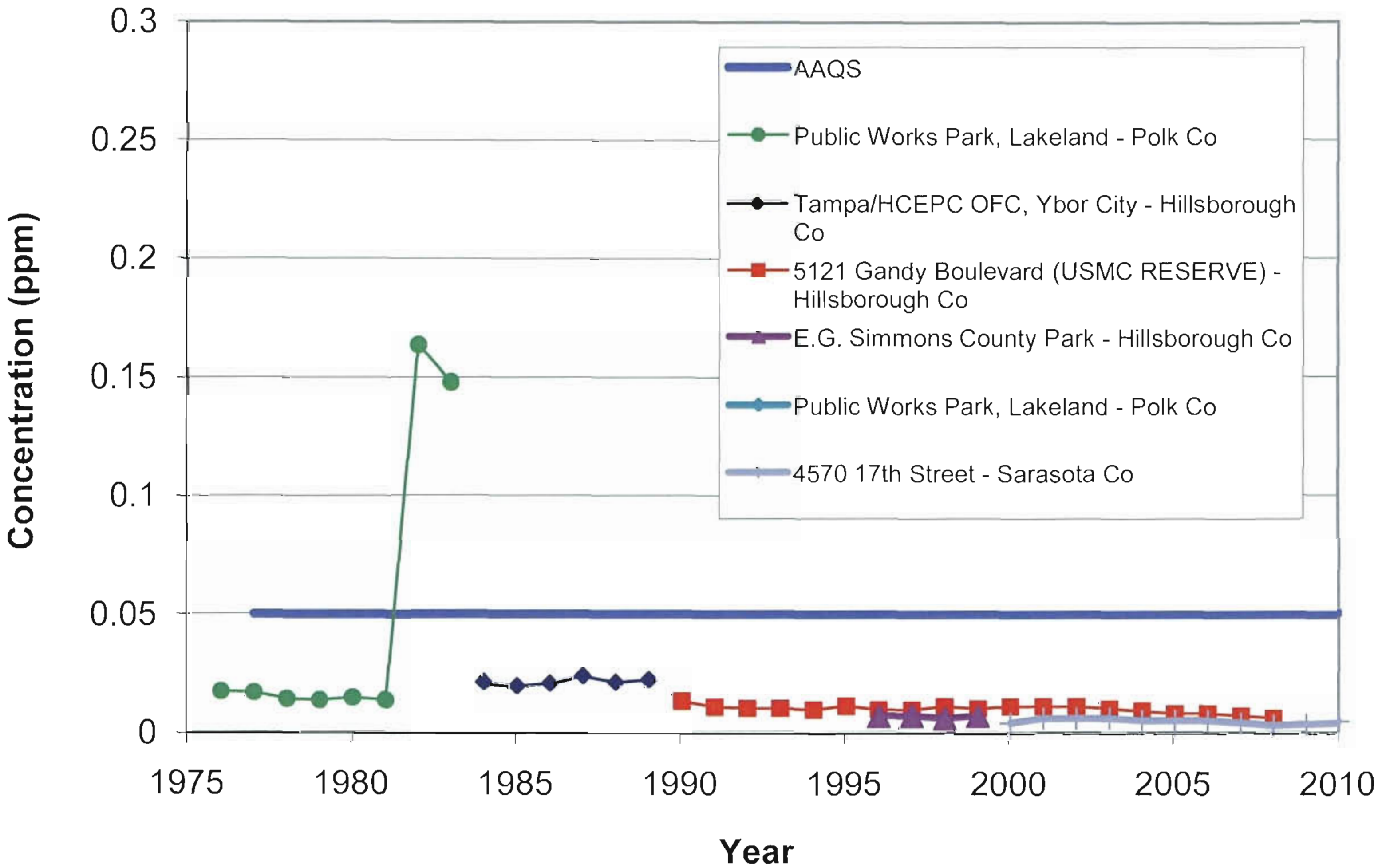
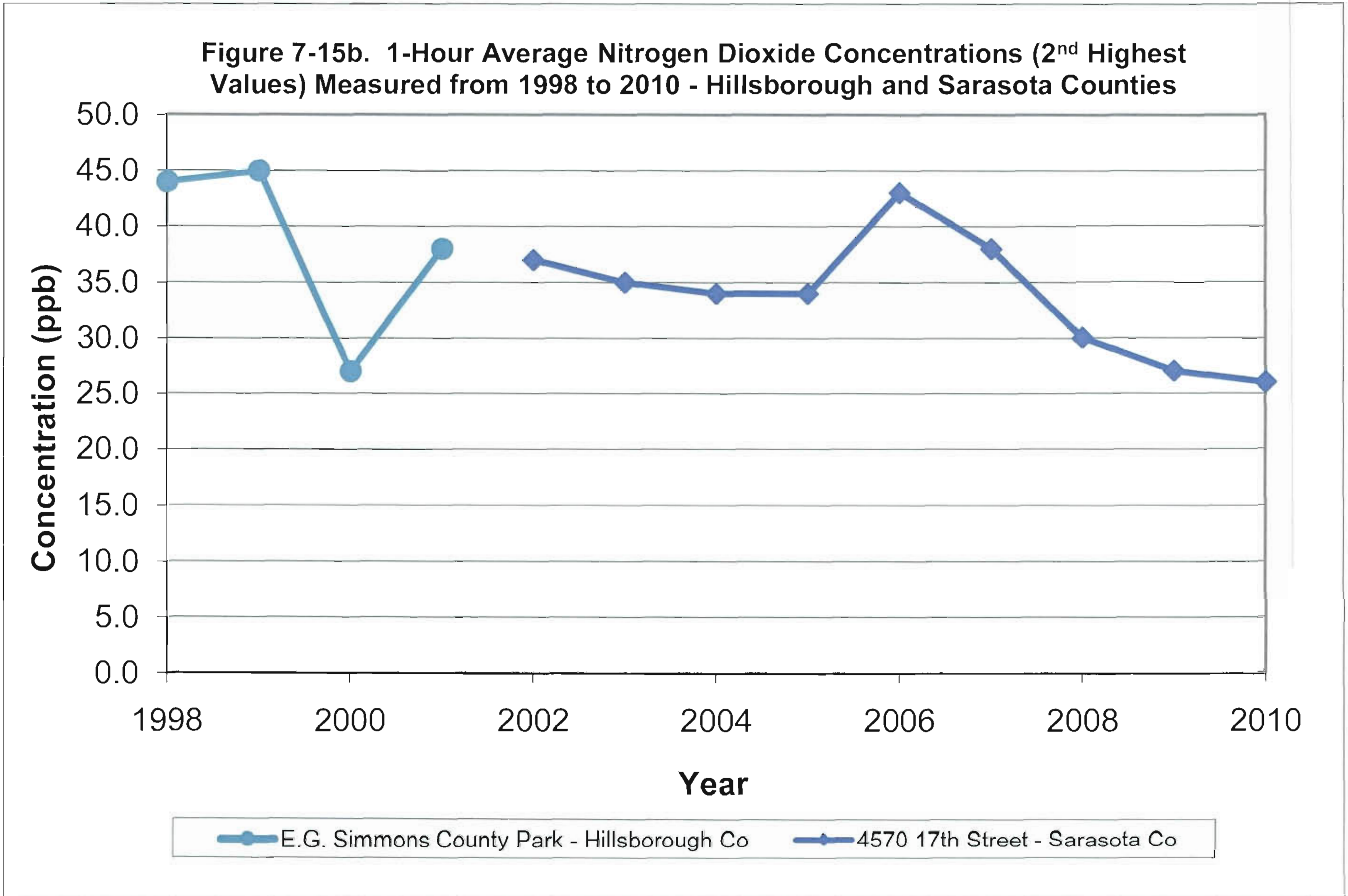
Figure 7-15a. Annual Average Nitrogen Dioxide Concentrations Measured from 1975 to 2010 - Polk, Hillsborough, Sarasota Counties






Golder Associates






Golder Associates

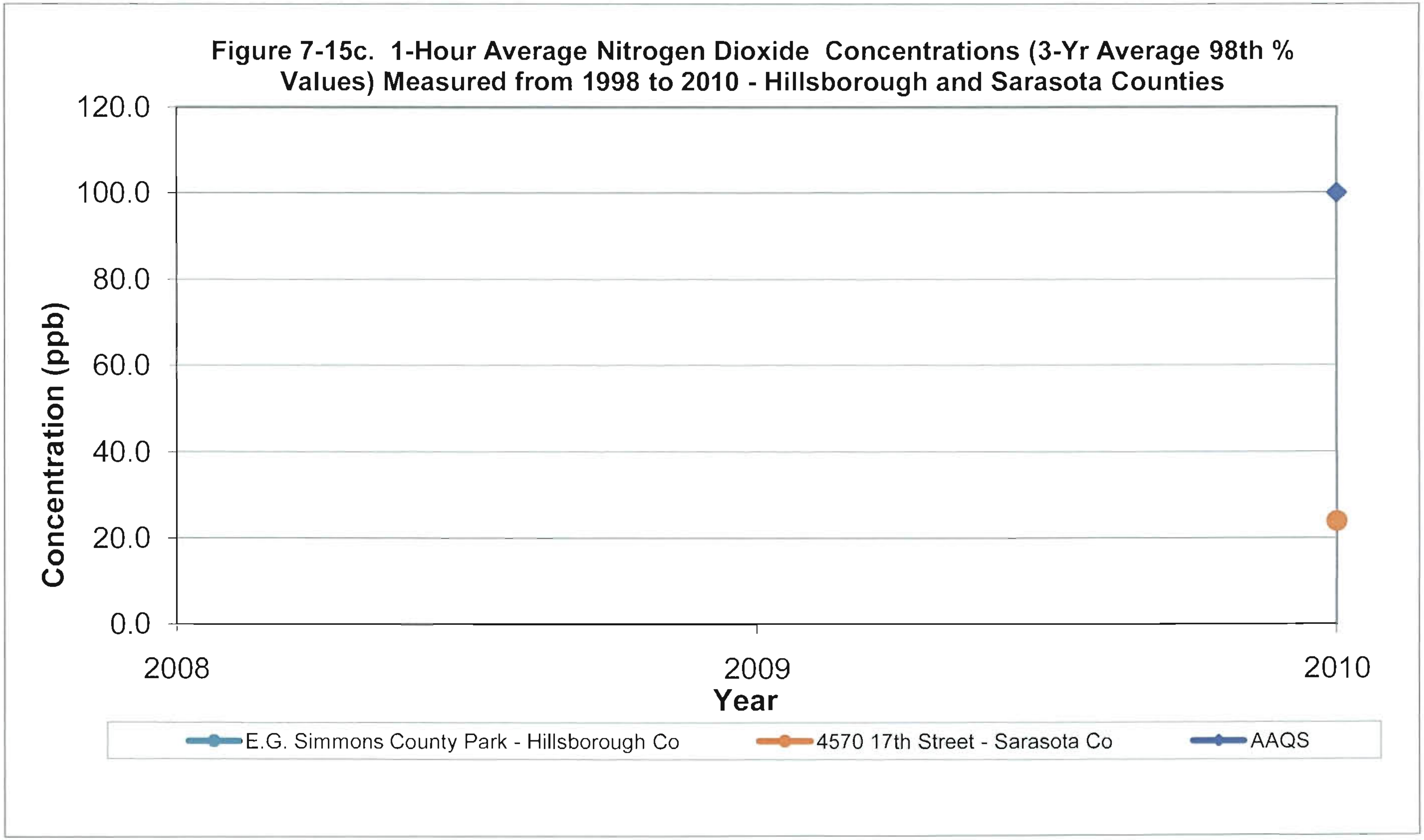
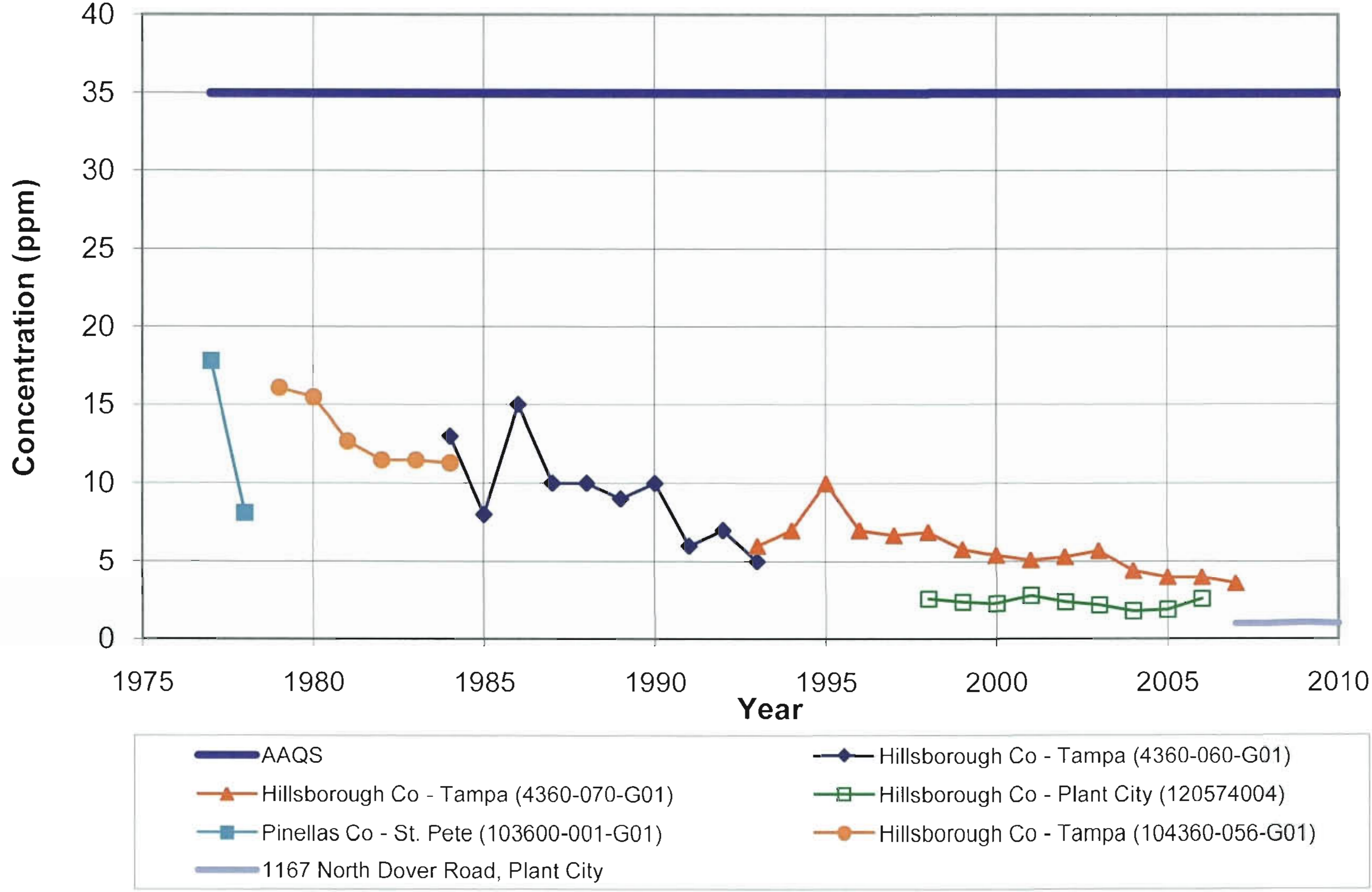


Figure 7-15c. 1-Hour Average Nitrogen Dioxide Concentrations (3-Yr Average 98th % Values) Measured from 1998 to 2010 - Hillsborough and Sarasota Counties
120.0
100.0
80.0
60.0
40.0
20.0
0.0
Concentration (ppb)
2008
2009
2010
Year
E.G. Simmons County Park - Hillsborough Co
4570 17th Street - Sarasota Co
AAQS

Figure 7-16. 1-hour Average Carbon Monoxide Concentrations (2nd Highest Values) Measured from 1977 to 2010 - Hillsborough and Pinellas Counties






Golder Associates

# Figure 7-17. 8-hour Average Carbon Monoxide Concentrations (2nd Highest Values) Measured from 1977 to 2010- Hillsborough and Pinellas Counties

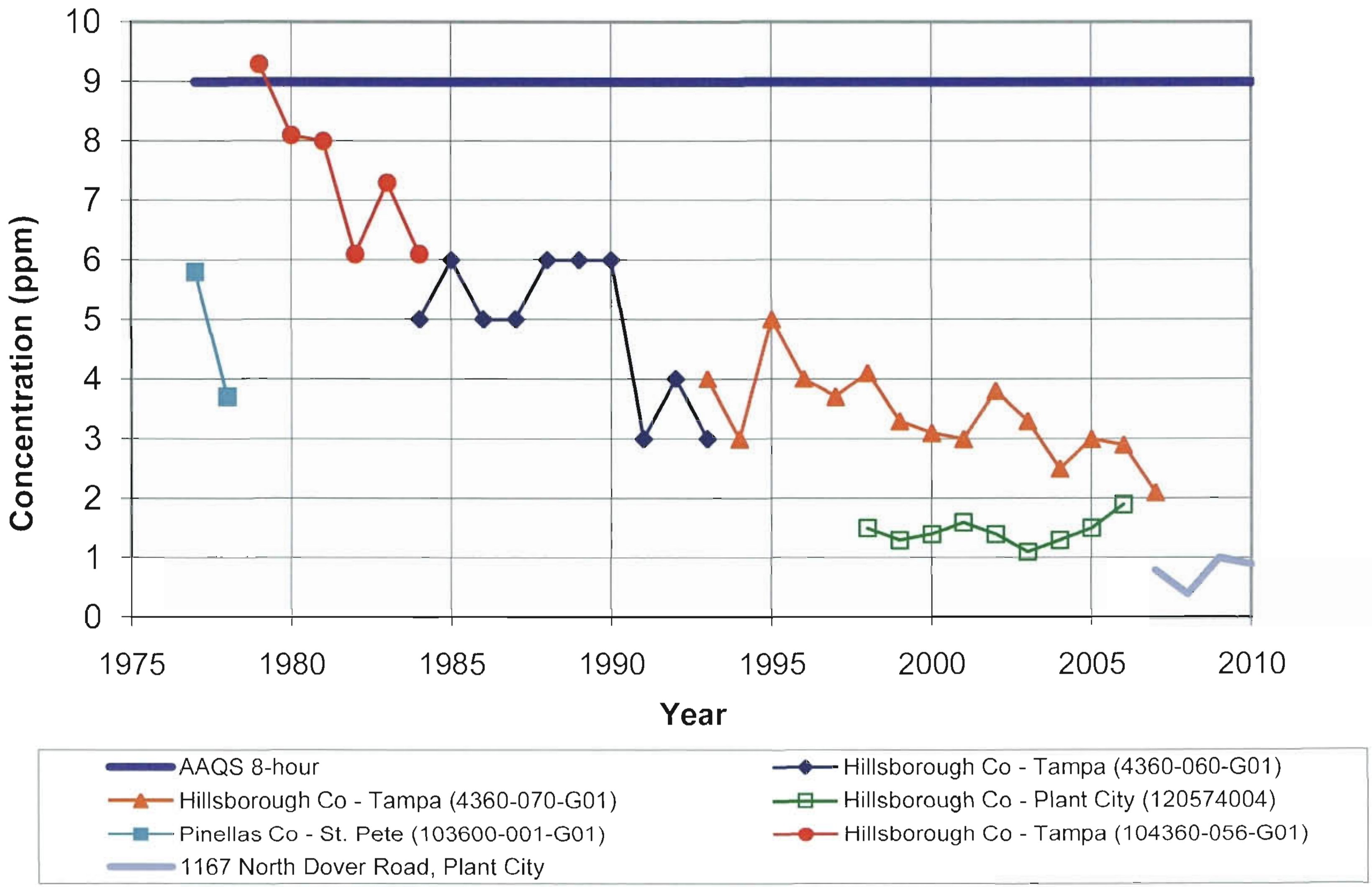
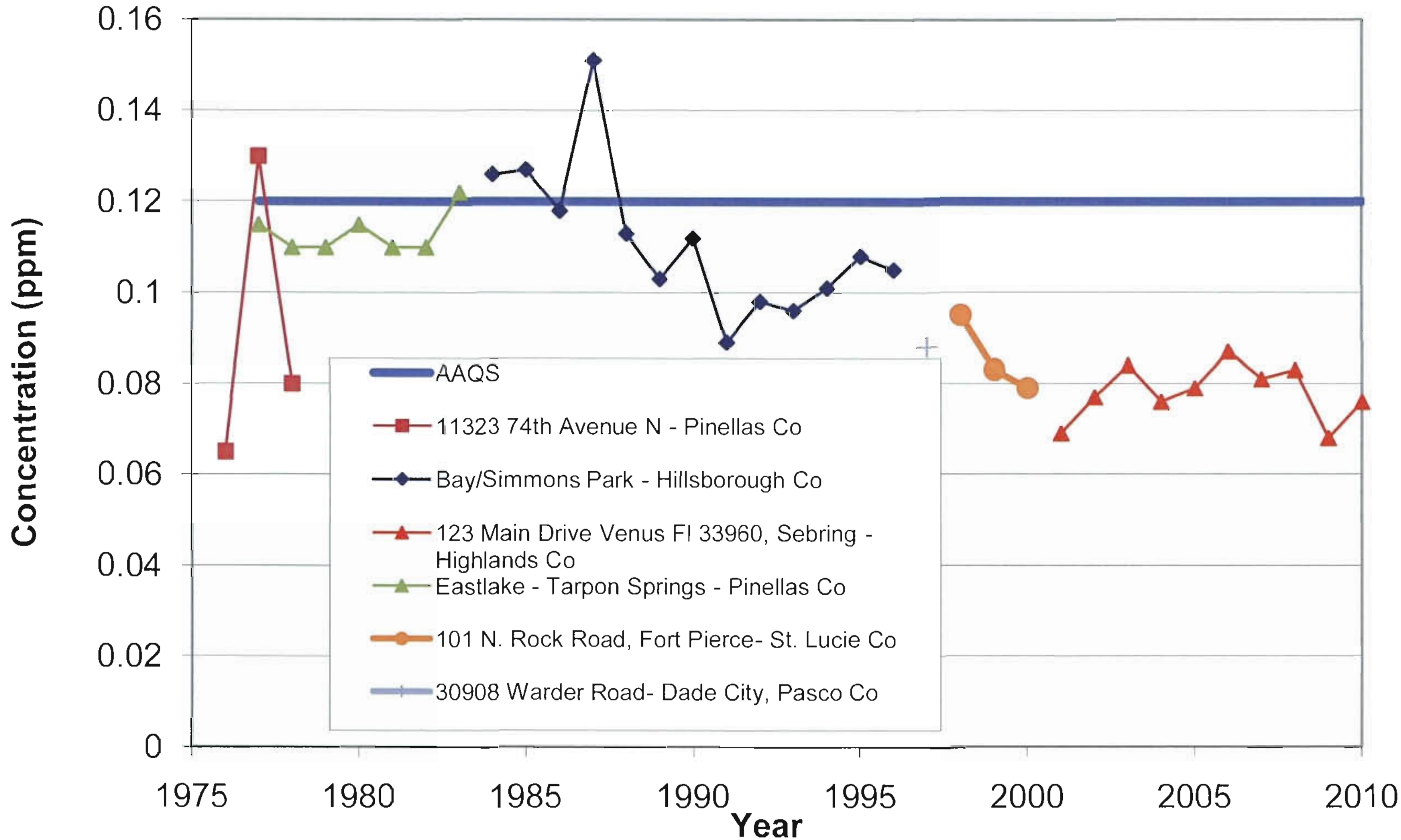


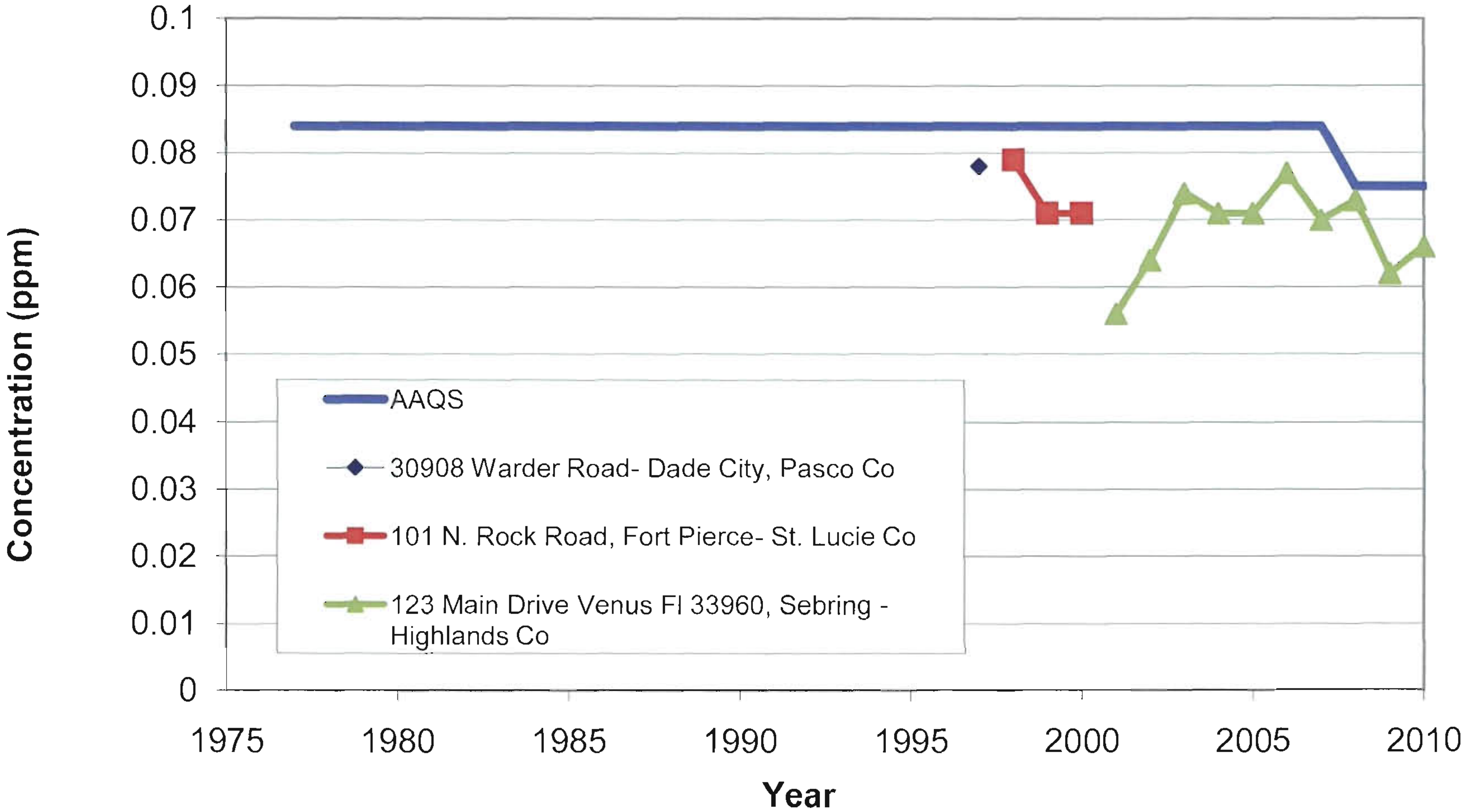
Figure 7-18. 1-hour Average Ozone Concentrations (2nd Highest Values) Measured from 1976 to 2010 - Highlands, St. Lucie, Pinellas, Hillsborough, and Pasco Counties






Golder Associates

Figure 7-19. 8-hour Average Ozone Concentrations (3-year Average of the 4th Highest Values) Measured from 1997 to 2010 - Highlands, St. Lucie, and Pasco Counties






Golder Associates

# APPENDIX A

# BOILER DESIGN DATA AND FUEL ANALYSIS

# APPENDIX A

## BOILER DESIGN DATA AND FUEL ANALYSIS

**1. Steam Production Basis:**

Maximum 1-hour: 275,000 lb/hr steam
Maximum 24-hour: 250,000 lb/hr steam

**2. Steam Enthalpy Calculation**

A. Steam conditions: 1,250 psig, 950°F
= 1,265 psia, 950°F
Enthalpy = 1,468.5Btu/lb

B. Feedwater condition: 1,405 psig, 250°F
= 1,420 psia, 250°F
Enthalpy = 221.5 Btu/lb

C. Net Enthalpy: 1,468.5 – 221.5 = 1,247 Btu/lb steam

**3. Heat Input Calculation (based on 68 percent thermal efficiency for biomass)**

A. Maximum 1-hour:
275,000 lb/hr steam x 1,247.1 Btu/lb ÷ 0.68 = 504.3 MMBtu/hr

B. Maximum 24-hour:
250,000 lb/hr steam x 1,247.0 Btu/lb ÷ 0.68 = 458.5 MMBtu/hr

C. Annual rate:
458.5 MMBtu/hr x 8,040 hr/yr = 3,686,281 MMBtu/yr

Table A-1. Fuel Analysis, Highlands EnviroFuels

| | Design Values | | Sugarcane Bagasse | | | | | | | | | Sweet Sorghum (IFAS Study, 2010) | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Sand | | | Muck | | | Sweet Sorghum (SRF Trial Burn, 2009) | | | Samples from 2009 (Avg.) | | | Samples from 2010 (Avg.) | | | |
| Parameter | Sugarcane Bagasse | Sorghum Bagasse | Min. | Max. | Avg. | Min. | Max. | Avg. | Min. | Max. | Avg. | Stem | Grain Head | Leaf | Unprocessed Stem | Washed Stem | Wood | Natural Gas |
| Specific Gravity | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – |
| Heating Value (Btu/lb) | 7,900, dry | 7,900, dry | 7,378, dry | 8,356, dry | 7,931, dry | 7,905, dry | 8,459, dry | 8,160, dry | 7,604, dry | 7,957, dry | 7,809, dry | – | – | – | – | – | 4,250, wet | – |
| Heating Value (Btu/gal) | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – |
| Heating Value (Btu/scf) | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | 1,020 |
| Ultimate Analysis (dry basis percentage): | | | | | | | | | | | | | | | | | | |
| Carbon | 49.6 | 46 | 46 | 51 | 48 | 48 | 53 | 50 | 43 | 47 | 46.2 | – | – | – | – | – | 49.6 | – |
| Hydrogen | 6.0 | 5.5 | 4.7 | 6.6 | 5.8 | 5.1 | 6.7 | 5.9 | 5.1 | 5.9 | 5.5 | – | – | – | – | – | 5.87 | – |
| Nitrogen | 0.4 | 0.64 | 0.25 | 0.55 | 0.39 | 0.28 | 0.55 | 0.40 | 0.28 | 1.37 | 0.6 | – | – | – | – | – | 0.4 | – |
| Oxygen | 40.8 | 41.8 | 37 | 43 | 40 | 38 | 44 | 41 | 40 | 44 | 42.2 | – | – | – | – | – | 40.9 | – |
| Sulfur | 0.12 | 0.22 | 0.03 | 0.09 | 0.07 | 0.03 | 0.08 | 0.06 | 0.09 | 0.44 | 0.2 | 0.04 | 0.11 | 0.20 | 0.04 | 0.01 | 0.07 | – |
| Ash/Inorganic | 3.04 | 5.6 | 0.9 | 10.6 | 5.0 | 1.1 | 6.2 | 2.2 | 4.3 | 9.2 | 5.8 | 2.2 | 5.9 | 5.0 | 1.9 | 2.1 | 9 | – |
| Chlorine | 0.04 | 0.24 | -- | -- | – | 0.013 | 0.030 | 0.019 | 0.041 | 0.39 | 0.2 | 0.31 | 0.18 | 0.73 | 0.26 | 0.15 | – | – |
| Moisture | NA | NA | 46 | 60 | 53 | 51 | 57 | 54 | 21 | 69 | 55.1 | – | – | – | – | – | 37-50 | – |
| Metals (dry basis, lb/MMBtu) | | | | | | | | | | | | | | | | | | |
| Arsenic | – | – | 1.89E-05 | 1.18E-04 | 5.56E-05 | 1.86E-05 | 1.11E-04 | 6.09E-05 | 1.14E-05 | 2.05E-05 | 1.43E-05 | – | – | – | – | – | – | – |
| Beryllium | – | – | 6.16E-06 | 1.36E-05 | 8.91E-06 | 5.96E-06 | 8.01E-05 | 1.15E-05 | 2.52E-05 | 3.85E-05 | 2.87E-05 | – | – | – | – | – | – | – |
| Cadmium | – | – | 6.16E-06 | 2.54E-05 | 1.09E-05 | 5.96E-06 | 1.48E-04 | 1.86E-05 | 1.51E-05 | 3.33E-05 | 2.07E-05 | – | – | – | – | – | – | – |
| Chromium | – | – | 1.24E-05 | 1.36E-04 | 5.82E-05 | 6.13E-06 | 9.93E-05 | 3.54E-05 | 1.53E-03 | 2.05E-03 | 1.75E-03 | – | – | – | – | – | – | – |
| Lead | – | – | 1.23E-05 | 1.18E-04 | 3.06E-05 | 1.84E-05 | 7.34E-05 | 3.11E-05 | 1.22E-03 | 2.31E-03 | 1.87E-03 | – | – | – | – | – | – | – |
| Manganese | – | – | 7.08E-04 | 2.29E-03 | 1.15E-03 | 6.55E-04 | 2.39E-03 | 1.21E-03 | 2.14E-04 | 1.10E-03 | 4.53E-04 | – | – | – | – | – | – | – |
| Nickel | – | – | 1.25E-05 | 9.87E-05 | 3.25E-05 | 1.20E-05 | 2.11E-04 | 3.50E-05 | 1.51E-04 | 9.61E-04 | 5.87E-04 | – | – | – | – | – | – | – |
| Mercury | – | – | 5.98E-07 | 2.53E-06 | 1.18E-06 | 5.91E-07 | 1.24E-06 | 8.08E-07 | 1.02E-05 | 1.38E-05 | 1.14E-05 | – | – | – | – | – | 5.70E-06 | – |
| Selenium | – | – | 5.07E-05 | 1.52E-04 | 9.85E-05 | 1.85E-05 | 1.43E-04 | 9.86E-05 | 6.29E-06 | 6.41E-06 | 6.37E-06 | – | – | – | – | – | – | – |

Note: values represent average fuel characteristics.

Sources:

1. Data for sugarcane bagasse, where the sugarcane was grown on primarily sandy type soil.
2. Data for sugarcane bagasse, where the sugarcane was grown on primarily muck type soil.
3. Sweet Sorghum: Southeast Renewable Fuels, LLC trial burn samples, September 2009.
4. Sweet Sorghum and Sweet Sorghum Bagasse: University of Florida (IFAS) Sweet Sorghum Report submitted to FDEP (September 2010).
5. Wood: New Hope Power Company (2008). Mercury value based on average sample value from US Sugar Clewiston Mill wood chip analysis (2006).
6. Fuel oil: Combustion Engineering, 1981.
7. Natural Gas: Section 1.4 of US EPA's AP-42.
8. Design values average values based on the fuel data which were used in the boiler design.

# APPENDIX B

# BIOMASS BOILER TEST DATA AND HAP CALCULATIONS

**Table B-1: Historical Stack Test Data, New Hope Power Company**

| Test Date | Unit | Fuel Type | Arsenic (lb/MMBtu) | Beryllium (lb/MMBtu) | Chromium (lb/MMBtu) | Copper (lb/MMBtu) | Lead (lb/MMBtu) | Mercury (lb/MMBtu) | Fluorides (lb/MMBtu) |
|---|---|---|---|---|---|---|---|---|---|
| **Pre-Mechanical Dust Collecors** | | | | | | | | | |
| 01/99-02/99 | Unit A | Wood | 4.80E-05 | <4.28E-07 | 2.36E-05 | 4.78E-05 | 3.00E-05 | 1.20E-06 | 9.38E-05 |
| | Unit B | Wood | 9.92E-05 | 5.09E-07 | 4.35E-05 | 7.31E-05 | 8.40E-05 | 1.50E-06 | 5.07E-05 |
| | Unit C | Wood | 4.88E-04 [a] | 6.09E-07 [a] | 3.11E-04 [a] | 2.89E-04 [a] | 4.00E-04 [a] | 3.60E-06 | 1.13E-04 |
| 01/99-02/99 | Unit A | Bagasse | 3.18E-05 | <3.77E-07 | 9.33E-06 | 2.55E-05 | 2.00E-05 | 4.41E-07 | 7.06E-05 |
| | Unit B | Bagasse | 6.50E-06 | <3.94E-07 | 5.85E-06 | 1.03E-05 | 7.30E-06 | 3.83E-07 | 4.07E-05 |
| | Unit C | Bagasse | 4.92E-06 | <1.25E-07 | 5.40E-06 | 1.33E-05 | 6.30E-06 | 5.41E-07 | 3.04E-05 |
| 12/99-01/00 | Unit A | Wood | 1.53E-05 | <2.56E-07 | 8.72E-06 | 2.60E-05 | 1.19E-05 | 6.25E-07 | 1.50E-04 |
| | Unit B | Wood | 9.05E-06 | <2.61E-07 | 2.12E-05 | 1.61E-05 | 7.97E-06 | 4.28E-07 | 1.60E-04 |
| | Unit C | Wood | 1.60E-05 | <2.68E-07 | 1.11E-05 | 3.08E-05 | 1.75E-05 | 6.52E-07 | 3.10E-04 |
| 12/99-01/00 | Unit A | Bagasse | 1.40E-06 | <2.22E-07 | 2.15E-06 | 8.67E-06 | 3.41E-06 | 1.26E-07 | 3.70E-04 |
| | Unit B | Bagasse | 5.42E-06 | <2.34E-07 | 4.54E-06 | 1.43E-05 | 6.68E-06 | 1.68E-07 | 4.40E-04 |
| | Unit C | Bagasse | 8.46E-06 | <2.52E-07 | 6.57E-06 | 2.67E-05 | 9.77E-06 | 5.34E-07 | 3.90E-04 |
| **Post-Mechanical Dust Collectors** | | | | | | | | | |
| 01/3/01-01/23/01 | Unit A | Wood | 1.13E-04 | <1.16E-07 | 4.12E-05 | 3.76E-05 | 7.49E-05 | 8.07E-07 | 7.00E-04 |
| | Unit B | Wood | 2.50E-05 | <1.10E-07 | 2.04E-05 | 1.42E-05 | 1.97E-05 | 8.09E-07 | 6.00E-04 |
| | Unit C | Wood | 3.78E-05 | <1.05E-07 | 2.71E-05 | 2.13E-05 | 3.91E-05 | 7.41E-07 | 6.00E-04 |
| 01/3/01-01/23/01 | Unit A | Bagasse | 6.34E-05 | <1.10E-07 | 5.22E-05 | 2.38E-05 | 3.81E-05 | 1.29E-06 | 6.00E-04 |
| | Unit B | Bagasse | 4.17E-05 | <1.07E-07 | 2.91E-05 | 2.23E-05 | 4.76E-05 | 1.41E-06 | 4.00E-04 |
| | Unit C | Bagasse | 4.40E-05 | 1.76E-07 | 2.41E-05 | 1.18E-05 | 1.63E-05 | 8.38E-07 | 3.00E-04 |
| 02/12/02-02/14/02 | Unit A | Biomass [b] | -- | -- | -- | -- | 2.08E-05 | 1.65E-06 | -- |
| | Unit B | Biomass [b] | -- | -- | -- | -- | 1.41E-05 | 9.70E-07 | -- |
| | Unit C | Biomass [b] | -- | -- | -- | -- | 2.09E-05 | 3.68E-06 | -- |

Sources: Air Consulting and Engineering, Inc., 2008; Golder, 2008.

[a] Results may not be representative due to high PM emissions.

[b] Biomass firing consisted of approximately 50% wood and 50% bagasse.

**Table B-2: Historical Stack Test Data, New Hope Power Company**

| Test Date | Unit | Fuel Type | Particulate (TSP) (lb/MMBtu) | Particulate ($PM_{10}$) (lb/MMBtu) | VOC (lb/MMBtu) | Mercury (lb/MMBtu) |
|---|---|---|---|---|---|---|
| **Pre-Mechanical Dust Collectors** | | | | | | |
| | Unit A | Wood | 0.140 | 0.020 | 0.004 | 1.20E-06 |
| 01/99-02/99 | Unit B | Wood | 0.080 | 0.020 | 0.005 | 1.50E-06 |
| | Unit C | Wood | 0.430 | 0.050 | 0.006 | 3.60E-06 |
| | Unit A | Bagasse | 0.270 | 0.020 | 0.01 | 4.41E-07 |
| 01/99-02/99 | Unit B | Bagasse | 0.120 | 0.010 | 0.02 | 3.83E-07 |
| | Unit C | Bagasse | 0.200 | 0.020 | 0.007 | 5.41E-07 |
| | Unit A | Wood | 0.138 | 0.0266 | 0.012 | 6.25E-07 |
| 12/99-01/00 | Unit B | Wood | 0.053 | 0.0148 | 0.006 | 4.28E-07 |
| | Unit C | Wood | 0.078 | 0.0158 | 0.006 | 6.52E-07 |
| | Unit A | Bagasse | 0.221 | 0.0282 | 0.010 | 1.26E-07 |
| 12/99-01/00 | Unit B | Bagasse | 0.039 | 0.0092 | 0.007 | 1.68E-07 |
| | Unit C | Bagasse | 0.230 | 0.0308 | 0.012 | 5.34E-07 |
| **Post-Mechanical Dust Collectors** | | | | | | |
| | Unit A | Wood | 0.022 | 0.025 | 0.002 | 8.07E-07 |
| 01/3/01-01/23/01 | Unit B | Wood | 0.013 | 0.0135 | 0.014 | 8.09E-07 |
| | Unit C | Wood | 0.022 | 0.023 | 0.003 | 7.41E-07 |
| | Unit A | Bagasse | 0.016 | 0.0153 | 0.007 | 1.29E-06 |
| 01/3/01-01/23/01 | Unit B | Bagasse | 0.021 | 0.0232 | 0.008 | 1.41E-06 |
| | Unit C | Bagasse | 0.010 | 0.0131 | 0.01 | 8.38E-07 |
| | Unit A | Biomass | 0.0080 | 0.0080 | 0.007 | 1.65E-06 |
| 02/12/02-02/14/02 [a] | Unit B | Biomass | 0.0100 | 0.0100 | 0.036 | 9.70E-07 |
| | Unit C | Biomass | 0.0110 | 0.0110 | 0.020 | 3.68E-06 |
| | Unit A | Biomass | 0.0089 | -- | 0.0027 | 7.55E-07 |
| 01/21/03-01/21/03 [a] | Unit B | Biomass | 0.0079 | -- | 0.0057 | 8.51E-07 |
| | Unit C | Biomass | 0.0081 | -- | 0.0580 | 1.10E-06 |
| | Unit A | Biomass | 0.0068 | -- | 0.0057 | 6.24E-07 |
| 02/11/04-02/16/04 [a] | Unit B | Biomass | 0.0098 | -- | 0.0067 | 3.51E-07 |
| | Unit C | Biomass | 0.0123 | -- | 0.0063 | 6.14E-07 |
| | Unit A | Biomass | 0.0162 | -- | 0.0013 | 2.66E-07 |
| 02/22/05-02/24/05 [a] | Unit B | Biomass | 0.0145 | -- | 0.0190 | 1.32E-06 |
| | Unit C | Biomass | 0.0123 | -- | 0.0063 | 6.14E-07 |
| | Unit A | Biomass | 0.0071 | -- | 0.0130 | 3.99E-07 |
| 02/14/06-02/16/06 [a] | Unit B | Biomass | 0.0100 | -- | 0.0057 | 9.11E-07 |
| | Unit C | Biomass | 0.0196 | -- | 0.0103 | 3.00E-07 |
| | Unit A | Biomass | 0.0128 | -- | 0.0083 | 1.11E-06 |
| 02/22/07-02/24/07 [a] | Unit B | Biomass | 0.0137 | -- | 0.0219 | 1.49E-06 |
| | Unit C | Biomass | 0.0148 | -- | 0.0104 | 2.50E-06 |
| | Unit A | Biomass | 0.0129 | -- | 0.0025 | 1.17E-06 |
| 02/6/08-02/8/08 [a] | Unit B | Biomass | 0.0130 | -- | 0.0022 | 8.69E-07 |
| | Unit C | Biomass | 0.0152 | -- | 0.0016 | 1.46E-06 |

Sources: Air Consulting and Engineering, Inc., 2008; Golder, 2008.

[a] Biomass firing consisted of approximately 50% wood and 50% bagasse.

**Table B-3: Historical Emission Tests Performed on Bagasse Fired Boilers with ESPs**

| Unit | Boiler Type | Test Date | Stack Gas Flow Rate (dscfm) | Stack Gas Flow Rate (acfm) | Steam Rate (lb/hr) | Heat Input Rate (MMBtu/hr) | Bagasse Burning Rate [1] (TPH) | $Cl_2$ Emissions (EPA Method 26A) lb/hr | $Cl_2$ Emissions (EPA Method 26A) lb/MMBtu | HCl Emissions (EPA Method 26A) lb/hr | HCl Emissions (EPA Method 26A) lb/MMBtu | Oxygen (%, dry) | Excess Air (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **US Sugar Corporation - Clewiston** | | | | | | | | | | | | | |
| Boiler 7 | Vibrating Grate | 12/31/02 | 164,558 | 311,596 | 295,652 | 625.71 | 86.90 | | | 0.4593 | 0.0007 | 8.50 | 68 |
| Boiler 7 | Vibrating Grate | 12/31/02 | 164,409 | 289,460 | 292,615 | 615.87 | 85.54 | | | 0.3647 | 0.0006 | 0.00 | 0 |
| Boiler 7 | Vibrating Grate | 12/31/02 | 149,851 | 290,446 | 288,000 | 606.59 | 84.25 | | | 0.1722 | 0.0003 | 0.00 | 0 |
| Boiler 7 | Vibrating Grate | 01/25/07 | 185,288 | 318,417 | 307,597 | 637.19 | 88.50 | 1.132 | 0.0022 | 0.9300 | 0.0018 | 10.56 | 102 |
| Boiler 7 | Vibrating Grate | 01/25/07 | 174,015 | 301,630 | 319,097 | 658.39 | 91.44 | 1.131 | 0.0025 | 0.7500 | 0.0014 | 9.78 | 88 |
| Boiler 7 | Vibrating Grate | 01/25/07 | 175,714 | 301,314 | 290,569 | 599.18 | 83.22 | 1.277 | 0.0026 | 2.8100 | 0.0057 | 10.71 | 105 |
| Boiler 8 | Traveling Grate | 03/24/05 | 236,278 | 441,324 | 518,571 | 982.6 | 136.47 | | | 3.1050 | 0.0032 | 6.52 | 45 |
| Boiler 8 | Traveling Grate | 03/24/05 | 218,901 | 416,739 | 487,595 | 880.2 | 122.24 | | | 4.1480 | 0.0047 | 6.96 | 50 |
| Boiler 8 | Traveling Grate | 03/25/05 | 218,815 | 416,838 | 496,578 | 919.1 | 127.66 | | | 3.5880 | 0.0039 | 6.53 | 45 |
| Boiler 8 | Traveling Grate | 03/26/05 | 205,956 | 399,189 | 470,930 | 921.2 | 127.94 | | | 9.1540 | 0.0099 | 6.20 | 42 |
| Boiler 8 | Traveling Grate | 03/26/05 | 204,635 | 400,819 | 467,580 | 908.9 | 126.23 | | | 3.4830 | 0.0038 | 6.00 | 41 |
| Boiler 8 | Traveling Grate | 03/26/05 | 208,161 | 395,735 | 466,000 | 887.6 | 123.28 | | | 3.6720 | 0.0041 | 6.34 | 44 |
| Boiler 8 | Traveling Grate | 06/02/06 | 160,360 | 286,469 | 238,876 | 547.0 | 75.97 | | | 1.9500 | 0.0088 | 9.22 | 79 |
| Boiler 8 | Traveling Grate | 06/02/06 | 152,745 | 271,874 | 215,692 | 481.3 | 66.84 | | | 0.6450 | 0.0021 | 9.84 | 89 |
| Boiler 8 | Traveling Grate | 06/02/06 | 124,942 | 218,045 | 222,067 | 428.3 | 59.48 | | | 0.7890 | 0.0052 | 9.10 | 77 |
| Boiler 8 | Traveling Grate | 01/05/07 | 237,896 | 406,875 | 499,726 | 919.5 | 127.71 | | | 0.7400 | 0.0011 | 7.73 | 59 |
| Boiler 8 | Traveling Grate | 01/05/07 | 236,384 | 429,330 | 520,274 | 960.3 | 133.38 | | | 3.0200 | 0.0043 | 7.65 | 58 |
| Boiler 8 | Traveling Grate | 01/05/07 | 229,933 | 443,786 | 510,811 | 948.0 | 131.67 | | | 1.1700 | 0.0015 | 7.25 | 53 |
| | Number of Runs | | | | | | | 3 | 3 | 18 | 18 | | |
| | **MEAN** | | | | | | | **1.180** | **0.0024** | **2.275** | **0.0035** | | |
| | MINIMUM | | | | | | | 1.131 | 0.0022 | 0.172 | 0.0003 | | |
| | **MAXIMUM** | | | | | | | **1.277** | **0.0026** | **9.154** | **0.0099** | | |

**Notes:**

lb/hr = pounds per hour.
lb/MMBtu = pounds per million British thermal units.
lb/ton = pounds per ton.
MMBtu/hr = million British thermal units per hour.
TPH = tons per hour.

Table B-4: Historical Emissions Tests Performed on Bagasse Boilers With ESPs Firing Wood

| Unit | Boiler Type / Fuel Description | Test Date | Stack Gas Flow Rate (dscfm) | Stack Gas Flow Rate (acfm) | Steam Rate (lb/hr) | Heat Input Rate (MMBtu/hr) | Bagasse Burning Rate [1] (TPH) | $CL_2$ Emissions (EPA Method 26A) lb/hr | $CL_2$ Emissions (EPA Method 26A) lb/MMBtu | HCl Emissions (EPA Method 26A) lb/hr | HCl Emissions (EPA Method 26A) lb/MMBtu | Oxygen (%, dry) | Excess Air (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **US Sugar Corporation - Clewiston** | | | | | | | | | | | | | |
| Boiler 7 | Vibrating Grate | 5/15/07 [1,3] | 140,530 | 228,015 | 267,761 | 554.51 | 61.61 | 0.006 | 0.0000 | 13.67 | 0.033 | 10.72 | 105 |
| Boiler 7 | Vibrating Grate | 5/15/07 [1] | 158,314 | 260,159 | 286,479 | 594.31 | 66.03 | 0.006 | 0.0000 | 15.69 | 0.031 | 10.10 | 93 |
| Boiler 7 | Vibrating Grate | 5/15/07 [1] | 158,028 | 259,395 | 288,750 | 596.40 | 66.27 | 0.006 | 0.0000 | 23.70 | 0.052 | 10.84 | 108 |
| Boiler 7 | Vibrating Grate | 5/15/07 [1,4] | 158,775 | 264,223 | 262,500 | 548.86 | 60.98 | 0.005 | 0.0000 | 19.63 | 0.043 | 10.85 | 108 |
| Boiler 7 | Vibrating Grate | 5/16/07 [1] | 156,667 | 260,669 | 240,952 | 504.25 | 56.03 | 0.060 | 0.0001 | 11.23 | 0.026 | 11.59 | 124 |
| Boiler 8 | Traveling Grate | 8/22/06 [2] | 148,855 | 262,552 | 202,933 | 403.5 | 44.83 | 1.100 | 0.0031 | 28.14 | 0.079 | 10.40 | 99 |
| Boiler 8 | Traveling Grate | 8/22/06 [2] | 146,795 | 256,382 | 202,604 | 383.6 | 42.62 | 0.900 | 0.0029 | 29.73 | 0.097 | 10.40 | 99 |
| Boiler 8 | Traveling Grate | 8/22/06 [2] | 148,794 | 257,466 | 199,219 | 411.4 | 45.71 | 0.790 | 0.0021 | 29.93 | 0.081 | 10.30 | 97 |
| **New Hope Power Company** | | | | | | | | | | | | | |
| Boiler A | 50/50 Wood/Bagasse | 02/16/04 | 182,772 | 328,287 | 392,840 | 654.4 | 72.72 | | | 20.75 | 0.0320 | 8.99 | 75 |
| Boiler A | 50/50 Wood/Bagasse | 02/24/05 | 161,263 | 313,883 | 398,600 | 644.4 | 71.60 | | | 2.53 | 0.0039 | 6.83 | 48 |
| Boiler B | 50/50 Wood/Bagasse | 02/12/04 | 159,831 | 304,728 | 411,380 | 645.3 | 71.70 | | | 16.09 | 0.0250 | 7.24 | 53 |
| Boiler B | 50/50 Wood/Bagasse | 02/12/04 | 169,463 | 319,916 | 411,380 | 701.7 | 77.97 | | | 16.61 | 0.0240 | 6.89 | 49 |
| Boiler B | 50/50 Wood/Bagasse | 02/23/05 | 172,350 | 334,975 | 381,550 | 659.8 | 73.31 | | | 4.03 | 0.0061 | 7.50 | 56 |
| Boiler B | Wood | 02/24/05 | 180,112 | 338,450 | 402,850 | 681.3 | 75.70 | | | 9.34 | 0.0148 | 8.81 | 73 |
| Boiler C | 50/50 Wood/Bagasse | 02/10/04 | 187,372 | 338,661 | 400,570 | 655.5 | 72.83 | | | 19.48 | 0.0300 | 8.96 | 75 |
| Boiler C | 50/50 Wood/Bagasse | 02/22/05 | 170,108 | 321,918 | 395,860 | 385.4 | 42.82 | | | 2.82 | 0.0073 | 13.48 | 181 |
| Boiler C | Wood | 02/23/05 | 182,035 | 343,332 | 381,940 | 701.6 | 77.96 | | | 2.74 | 0.0040 | 7.68 | 58 |
| | Number of Runs | | | | | | | 6 | 6 | 15 | 15 | 15 | 15 |
| | **MEAN** | | | | | | | **0.477** | **0.0014** | **15.52** | **0.034** | **9.33** | **86** |
| | MINIMUM | | | | | | | 0.006 | 0.00001 | 2.53 | 0.004 | 6.83 | 48 |
| | **MAXIMUM** | | | | | | | **1.100** | **0.0031** | **29.93** | **0.097** | **13.48** | **181** |

**Notes:**
lb/hr = pounds per hour.
lb/MMBtu = pounds per million British thermal units.
lb/ton = pounds per ton.
MMBtu/hr = million British thermal units per hour.
TPH = tons per hour.

**Footnotes:**
[1] 50% Wood Chip / 50% Bagasse.
[2] Wood chip firing at 4,500 Btu/lb. Data corresponding to wood chips was not used in any of the summary calculations.
[3] Run was not included in calculations because of problems with measurements.
[4] Feeders clogged and run was incomplete, therefore not included in calculations.

**Table B-5: Annual Emissions of Hazardous Air Pollutants from the Biomass Boiler, 100% Bagasse Scenario**

| | Sugarcane Bagasse | | | | | Sorghum Bagasse | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HAP | Emission Factor (lb/MMBtu) | Ref | Activity Factor ($10^{12}$ Btu/yr) | Control Efficiency (%) | Annual Emissions (TPY) | Emission Factor (lb/MMBtu) | Ref | Activity Factor ($10^{12}$ Btu/yr) | Control Efficiency (%) | Annual Emissions (TPY) | Total Emissions (TPY) | |
| **Biomass Boiler** | | | | | | | | | | | | |
| Acetaldehyde | UD | 2 | 1.843 | | UD | UD | 2 | 1.843 | | UD | UD | Acetaldehyde |
| Acetophenone | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | Acetophenone |
| Acrolein | UD | 2 | 1.843 | | UD | UD | 2 | 1.843 | | UD | UD | Acrolein |
| Antimony | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | Antimony |
| Arsenic[a] | 2.05E-05 | 4 | 1.843 | 90 | 0.0019 | 2.05E-05 | 4 | 1.843 | 90 | 0.0019 | 0.0038 | Arsenic[a] |
| Benzene | 8.43E-04 | 2 | 1.843 | | 0.78 | 8.43E-04 | 2 | 1.843 | | 0.78 | 1.5538 | Benzene |
| Beryllium[a] | 3.85E-05 | 4 | 1.843 | 90 | 0.0035 | 3.85E-05 | 4 | 1.843 | 90 | 0.0035 | 0.0071 | Beryllium[a] |
| bis(2ethylhexyl)phthalate | 4.20E-04 | 2 | 1.843 | | 0.39 | 4.20E-04 | 2 | 1.843 | | 0.39 | 0.7741 | bis(2ethylhexyl)phthalate |
| Cadmium[a] | 3.33E-05 | 4 | 1.843 | 90 | 0.0031 | 3.33E-05 | 4 | 1.843 | 90 | 0.0031 | 0.0061 | Cadmium[a] |
| Carbon Disulfide | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | Carbon Disulfide |
| Carbon Tetrachloride | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | Carbon Tetrachloride |
| Chlorine | 0.00014 | 3 | 1.843 | | 0.13 | 0.0032 | 6 | 1.843 | | 2.95 | 3.08 | Chlorine |
| Chlorobenzene | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | Chlorobenzene |
| Chloroform | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | Chloroform |
| Chromium[a] | 1.79E-03 | 4 | 1.843 | 90 | 0.16 | 1.79E-03 | 4 | 1.843 | 90 | 0.16 | 0.33 | Chromium[a] |
| Chromium+6 | 3.17E-04 | 5 | 1.843 | 90 | 0.029 | 3.17E-04 | 5 | 1.843 | 90 | 0.029 | 0.058 | Chromium+6 |
| Cobalt | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | Cobalt |
| m&p-Cresol | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | m&p-Cresol |
| Cumene | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | Cumene |
| Dibenzofurans | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | Dibenzofurans |
| Dibutylphthalate | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | Dibutylphthalate |
| 1,4-Dichlorobenzene(p) | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | 1,4-Dichlorobenzene(p) |
| Ethylbenzene | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | Ethylbenzene |
| Formaldehyde | 1.13E-03 | 2 | 1.843 | | 1.041 | 1.13E-03 | 2 | 1.843 | | 1.041 | 2.08 | Formaldehyde |
| Hexane | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | Hexane |
| Hydrogen Chloride[b] | 0.0035 | 3 | 1.843 | 0 | 3.225 | 0.080 | 6 | 1.843 | 95 | 3.686 | 6.91 | Hydrogen Chloride[b] |
| Hydrogen Fluoride | 3.01E-04 | 1 | 1.843 | 92 | 0.022 | 3.01E-04 | 1 | 1.843 | 92 | 0.022 | 0.044 | Hydrogen Fluoride |
| Lead-Total[a] | 9.61E-04 | 4 | 1.843 | 90 | 0.089 | 9.61E-04 | 4 | 1.843 | 90 | 0.089 | 0.18 | Lead-Total[a] |
| Manganese[a] | 2.31E-03 | 4 | 1.843 | 90 | 0.213 | 2.31E-03 | 4 | 1.843 | 90 | 0.213 | 0.43 | Manganese[a] |
| Mercury[a] | 1.38E-05 | 4 | 1.843 | | 0.013 | 1.38E-05 | 4 | 1.843 | | 0.013 | 0.025 | Mercury[a] |
| Methanol | UD | 2 | 1.843 | | UD | UD | 2 | 1.843 | | UD | UD | Methanol |
| Methyl Isobutyl Ketone | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | Methyl Isobutyl Ketone |
| Methylene Chloride | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | Methylene Chloride |
| Nickel[a] | 1.10E-03 | 4 | 1.843 | 90 | 0.10 | 1.10E-03 | 4 | 1.843 | 90 | 0.10 | 0.20 | Nickel[a] |
| 4-Nitrophenol | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | 4-Nitrophenol |
| Pentachlorophenol (PCP) | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | Pentachlorophenol (PCP) |
| Phenols | 1.12E-05 | 2 | 1.843 | | 0.0103 | 1.12E-05 | 2 | 1.843 | | 0.0103 | 0.021 | Phenols |
| Phosphorus | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | Phosphorus |
| Propionaldehyde | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | Propionaldehyde |
| Selenium[a] | 6.41E-06 | 4 | 1.843 | 90 | 0.0059 | 6.41E-06 | 4 | 1.843 | 90 | 0.0059 | 0.012 | Selenium[a] |
| Styrene | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | Styrene |
| Dioxin/Furan (2, 3, 7, 8-Tetrachlorodibenzo-p-dioxin) | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | Dioxin/Furan (2, 3, 7, 8-Tetrachlorodibenzo-p-dioxin) |
| Toluene | 3.36E-05 | 2 | 1.843 | | 0.031 | 3.36E-05 | 2 | 1.843 | | 0.031 | 0.062 | Toluene |
| 1, 1, 2-Trichloroethane | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | 1, 1, 2-Trichloroethane |
| Trichloroethylene | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | Trichloroethylene |
| Vinyl Chloride | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | Vinyl Chloride |
| m- & p-Xylene | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | m- & p-Xylene |
| o-Xylene | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | o-Xylene |

Table B-5: Annual Emissions of Hazardous Air Pollutants from the Biomass Boiler, 100% Bagasse Scenario

| HAP | Sugarcane Bagasse Emission Factor (lb/MMBtu) | Ref | Activity Factor ($10^{12}$ Btu/yr) | Control Efficiency (%) | Annual Emissions (TPY) | Sorghum Bagasse Emission Factor (lb/MMBtu) | Ref | Activity Factor ($10^{12}$ Btu/yr) | Control Efficiency (%) | Annual Emissions (TPY) | Total Emissions (TPY) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **POMs** | | | | | | | | | | | | **POMs** |
| 3-Methylcholanthrene | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | 3-Methylcholanthrene |
| Acenaphthene | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | Acenaphthene |
| Acenaphthylene | 7.94E-07 | 2 | 1.843 | | 0.00073 | 7.94E-07 | 2 | 1.843 | | 0.00073 | 0.0015 | Acenaphthylene |
| Anthracene | 2.01E-07 | 2 | 1.843 | | 0.00019 | 2.01E-07 | 2 | 1.843 | | 0.00019 | 0.00037 | Anthracene |
| Benzo (a) anthracene | 1.06E-06 | 2 | 1.843 | | 0.0010 | 1.06E-06 | 2 | 1.843 | | 0.0010 | 0.0020 | Benzo (a) anthracene |
| Benzo(a)pyrene | 1.00E-06 | 2 | 1.843 | | 0.00092 | 1.00E-06 | 2 | 1.843 | | 0.00092 | 0.0018 | Benzo(a)pyrene |
| Benzo(b)fluoranthene | 1.06E-06 | 2 | 1.843 | | 0.0010 | 1.06E-06 | 2 | 1.843 | | 0.0010 | 0.0020 | Benzo(b)fluoranthene |
| Benzo(e)pyrene | 1.06E-06 | 2 | 1.843 | | 0.0010 | 1.06E-06 | 2 | 1.843 | | 0.0010 | 0.0020 | Benzo(e)pyrene |
| Benzo(g,h,i)perylene | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | Benzo(g,h,i)perylene |
| Benzo(j,k)fluoranthene | 9.01E-07 | 2 | 1.843 | | 0.00083 | 9.01E-07 | 2 | 1.843 | | 0.00083 | 0.0017 | Benzo(j,k)fluoranthene |
| Chrysene | 1.82E-06 | 2 | 1.843 | | 0.0017 | 1.82E-06 | 2 | 1.843 | | 0.0017 | 0.0034 | Chrysene |
| Dibenzo(a,h)anthracene | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | Dibenzo(a,h)anthracene |
| Dimethylbenz(a)anthracene | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | Dimethylbenz(a)anthracene |
| Fluoranthene | 2.88E-06 | 2 | 1.843 | | 0.0027 | 2.88E-06 | 2 | 1.843 | | 0.0027 | 0.0053 | Fluoranthene |
| Fluorene | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | Fluorene |
| indeno(1,2,3-cd)pyrene | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | indeno(1,2,3-cd)pyrene |
| Naphthalene | 1.80E-05 | 2 | 1.843 | | 0.0166 | 1.80E-05 | 2 | 1.843 | | 0.017 | 0.033 | Naphthalene |
| Perylene | ND | | 1.843 | | ND | ND | | 1.843 | | ND | ND | Perylene |
| Phenanthrene | 2.71E-06 | 2 | 1.843 | | 0.0025 | 2.71E-06 | 2 | 1.843 | | 0.0025 | 0.0050 | Phenanthrene |
| Pyrene | 2.71E-06 | 2 | 1.843 | | 0.0025 | 2.71E-06 | 2 | 1.843 | | 0.0025 | 0.0050 | Pyrene |
| Total POMs** | | | | | 0.032 | | | | | 0.032 | 0.063 | Total POMs** |
| **MAXIMUM SINGLE HAP** | | | | | **3.23** | | | | | **3.69** | **6.91** | **MAXIMUM SINGLE HAP** |
| **TOTAL** | | | | | **6.28** | | | | | **9.56** | **15.84** | **TOTAL** |

UD = Undetected
ND = No Data available
[a] Assumed 90% control efficiency for all metals, except mercury for which zero control was assumed.
[b] For HCl a control efficiency of 92 percent was applied for all fuels.
[c] No HAP factors available for propane; therefore, factors for Natural Gas are used, assuming 1,020 Btu/scf for Natural Gas.

References
1. Based on the average of stack test results for New Hope Power Company Boilers A, B, and C (1999-2002) excluding 1999 wood test for Unit C.
2. Based on HAP Emissions for U.S. Sugar-Clewiston Boiler 7 - Geometric mean of three runs January 31, 2000.
3. Based on HAP testing of bagasse fired boilers. Average of 18 runs for HCl. Emissions for $Cl_2$ based on AP-42 for wood firing and Appendix B, Table B-4, which shows 4% of HCl is emitted as $Cl_2$.
4. Based on the maximum of fuel analysis results for SRF sweet sorghum analysis conducted 9/9/2009, tested in US Sugar Clewiston Boiler No. 7.
5. Based on the ratio of wood emission factor for Chromium VI to Chromium.
6. Based on maximum chlorine content of sorghum (0.24% Cl or 0.32 lb/MMBtu as HCl) and assuming 75% inherent removal in ash. Chlorine emissions are 4% of HCl, based on AP-42 for wood firing and Appendix B, Table B-4.
**Sum of all POMs, unless emission factors are only listed for Total POMs, not individuals, and will be noted.

**Table B-6: Annual Emissions of Hazardous Air Pollutants from the Biomass Boiler, 10% Wood Scenario**

| | Sugarcane Bagasse | | | | | Sorghum Bagasse | | | | | Wood | | | | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HAP | Emission Factor (lb/MMBtu) | Ref | Activity Factor ($10^{12}$ Btu/yr) | Control Efficiency (%) | Annual Emissions (TPY) | Emission Factor (lb/MMBtu) | Ref | Activity Factor ($10^{12}$ Btu/yr) | Control Efficiency (%) | Annual Emissions (TPY) | Emission Factor (lb/MMBtu) | Ref | Activity Factor ($10^{12}$ Btu/yr) | Control Efficiency (%) | Annual Emissions (TPY) | Maximum Emissions for All Fuels (TPY) | |
| **Biomass Boiler** | | | | | | | | | | | | | | | | | |
| Acetaldehyde | UD | 2 | 1.659 | | UD | UD | 2 | 1.659 | | UD | 8.3E-04 | 3 | 0.369 | | 0.15 | 0.15 | Acetaldehyde |
| Acetophenone | ND | | 1.659 | | ND | ND | | 1.659 | | ND | 3.2E-09 | 3 | 0.369 | | 5.9E-07 | 5.9E-07 | Acetophenone |
| Acrolein | UD | 2 | 1.659 | | UD | UD | 2 | 1.659 | | UD | 4.0E-03 | 3 | 0.369 | | 0.74 | 0.74 | Acrolein |
| Antimony | ND | | 1.659 | | ND | ND | | 1.659 | | ND | 7.90E-06 | 3 | 0.369 | | 0.0015 | 0.0015 | Antimony |
| Arsenic[a] | 2.05E-05 | 6 | 1.659 | 90 | 0.0017 | 2.05E-05 | 6 | 1.659 | 90 | 0.0017 | 3.36E-05 | 1 | 0.369 | 90 | 0.00062 | 0.0040 | Arsenic[a] |
| Benzene | 8.43E-04 | 2 | 1.659 | | 0.70 | 8.43E-04 | 2 | 1.659 | | 0.70 | 4.20E-03 | 3 | 0.369 | | 0.77 | 2.17 | Benzene |
| Beryllium[a] | 3.85E-05 | 6 | 1.659 | 90 | 0.0032 | 3.85E-05 | 6 | 1.659 | 90 | 0.0032 | 2.38E-07 | 1 | 0.369 | 90 | 4.4E-06 | 0.0064 | Beryllium[a] |
| bis(2ethylhexyl)phthalate | 4.20E-04 | 2 | 1.659 | | 0.348 | 4.20E-04 | 2 | 1.659 | | 0.348 | 4.7E-08 | 3 | 0.369 | | 8.7E-06 | 0.70 | bis(2ethylhexyl)phthalate |
| Cadmium[a] | 3.33E-05 | 6 | 1.659 | 90 | 0.0028 | 3.33E-05 | 6 | 1.659 | 90 | 0.0028 | 4.1E-06 | 3 | 0.369 | 90 | 0.000076 | 0.0056 | Cadmium[a] |
| Carbon Disulfide | ND | | 1.659 | | ND | ND | | 1.659 | | ND | ND | | 0.369 | | ND | ND | Carbon Disulfide |
| Carbon Tetrachloride | ND | | 1.659 | | ND | ND | | 1.659 | | ND | 4.50E-05 | 3 | 0.369 | | 0.0083 | 0.0083 | Carbon Tetrachloride |
| Chlorine | 0.00014 | 5 | 1.659 | | 0.12 | 0.0032 | 8 | 1.659 | | 2.65 | 0.0014 | 4 | 0.369 | | 0.26 | 3.03 | Chlorine |
| Chlorobenzene | ND | | 1.659 | | ND | ND | | 1.659 | | ND | 3.3E-05 | 3 | 0.369 | | 0.0061 | 0.0061 | Chlorobenzene |
| Chloroform | ND | | 1.659 | | ND | ND | | 1.659 | | ND | 2.8E-05 | 3 | 0.369 | | 0.0052 | 0.0052 | Chloroform |
| Chromium[a] | 1.79E-03 | 6 | 1.659 | 90 | 0.15 | 1.79E-03 | 6 | 1.659 | 90 | 0.15 | 1.98E-05 | 1 | 0.369 | 90 | 0.00036 | 0.30 | Chromium[a] |
| Chromium+6 | 3.17E-04 | 7 | 1.659 | 90 | 0.026 | 3.17E-04 | 7 | 1.659 | 90 | 0.026 | 3.50E-06 | 3 | 0.369 | 90 | 0.000065 | 0.053 | Chromium+6 |
| Cobalt | ND | | 1.659 | | ND | ND | | 1.659 | | ND | 6.50E-06 | 3 | 0.369 | | 0.0012 | 0.0012 | Cobalt |
| m&p-Cresol | ND | | 1.659 | | ND | ND | | 1.659 | | ND | ND | | 0.369 | | ND | ND | m&p-Cresol |
| Cumene | ND | | 1.659 | | ND | ND | | 1.659 | | ND | ND | | 0.369 | | ND | ND | Cumene |
| Dibenzofurans | ND | | 1.659 | | ND | ND | | 1.659 | | ND | 1.78E-09 | 3 | 0.369 | | 3.3E-07 | 3.3E-07 | Dibenzofurans |
| Dibutylphthalate | ND | | 1.659 | | ND | ND | | 1.659 | | ND | ND | | 0.369 | | ND | ND | Dibutylphthalate |
| 1,4-Dichlorobenzene(p) | ND | | 1.659 | | ND | ND | | 1.659 | | ND | ND | | 0.369 | | ND | ND | 1,4-Dichlorobenzene(p) |
| Ethylbenzene | ND | | 1.659 | | ND | ND | | 1.659 | | ND | 3.1E-05 | 3 | 0.369 | | 0.0057 | 0.0057 | Ethylbenzene |
| Formaldehyde | 1.13E-03 | 2 | 1.659 | | 0.94 | 1.13E-03 | 2 | 1.659 | | 0.94 | 4.40E-03 | 3 | 0.369 | | 0.81 | 2.69 | Formaldehyde |
| Hexane | ND | | 1.659 | | ND | ND | | 1.659 | | ND | ND | | 0.369 | | ND | ND | Hexane |
| Hydrogen Chloride[b] | 0.0035 | 5 | 1.659 | 0 | 2.90 | 0.080 | 8 | 1.659 | 95 | 3.32 | 0.034 | 4 | 0.369 | 90 | 0.63 | 6.85 | Hydrogen Chloride[b] |
| Hydrogen Fluoride | 3.01E-04 | 1 | 1.659 | 92 | 0.020 | 3.01E-04 | 1 | 1.659 | 92 | 0.020 | 3.01E-04 | 1 | 0.369 | 92 | 0.0044 | 0.044 | Hydrogen Fluoride |
| Lead-Total[a] | 9.61E-04 | 6 | 1.659 | 90 | 0.080 | 9.61E-04 | 6 | 1.659 | 90 | 0.080 | 2.48E-05 | 1 | 0.369 | 90 | 0.00046 | 0.16 | Lead-Total[a] |
| Manganese[a] | 2.31E-03 | 6 | 1.659 | 90 | 0.19 | 2.31E-03 | 6 | 1.659 | 90 | 0.19 | 1.60E-03 | 3 | 0.369 | 90 | 0.029 | 0.41 | Manganese[a] |
| Mercury[a] | 1.38E-05 | 6 | 1.659 | | 0.011 | 1.38E-05 | 6 | 1.659 | | 0.011 | 1.00E-06 | 1 | 0.369 | | 0.00018 | 0.023 | Mercury[a] |
| Methanol | UD | 2 | 1.659 | | UD | UD | 2 | 1.659 | | UD | ND | | 0.369 | | ND | ND | Methanol |
| Methyl Isobutyl Ketone | ND | | 1.659 | | ND | ND | | 1.659 | | ND | ND | | 0.369 | | ND | ND | Methyl Isobutyl Ketone |
| Methylene Chloride | ND | | 1.659 | | ND | ND | | 1.659 | | ND | ND | | 0.369 | | ND | ND | Methylene Chloride |
| Nickel[a] | 1.10E-03 | 6 | 1.659 | 90 | 0.091 | 1.10E-03 | 6 | 1.659 | 90 | 0.091 | 3.30E-05 | 3 | 0.369 | 90 | 0.00061 | 0.18 | Nickel[a] |
| 4-Nitrophenol | ND | | 1.659 | | ND | ND | | 1.659 | | ND | 1.10E-07 | 3 | 0.369 | | 0.000020 | 2.0E-05 | 4-Nitrophenol |
| Pentachlorophenol (PCP) | ND | | 1.659 | | ND | ND | | 1.659 | | ND | 5.10E-08 | 3 | 0.369 | | 9.4E-06 | 9.4E-06 | Pentachlorophenol (PCP) |
| Phenols | 1.12E-05 | 2 | 1.659 | | 0.0093 | 1.12E-05 | 2 | 1.659 | | 0.0093 | 5.10E-05 | 3 | 0.369 | | 0.0094 | 0.028 | Phenols |
| Phosphorus | ND | | 1.659 | | ND | ND | | 1.659 | | ND | 2.70E-05 | 3 | 0.369 | | 0.0050 | 0.0050 | Phosphorus |
| Propionaldehyde | ND | | 1.659 | | ND | ND | | 1.659 | | ND | 6.10E-05 | 3 | 0.369 | | 0.011 | 0.011 | Propionaldehyde |
| Selenium[a] | 6.41E-06 | 6 | 1.659 | 90 | 0.0053 | 6.41E-06 | 6 | 1.659 | 90 | 0.0053 | 2.80E-06 | 3 | 0.369 | 90 | 5.2E-05 | 0.011 | Selenium[a] |
| Styrene | ND | | 1.659 | | ND | ND | | 1.659 | | ND | 1.90E-03 | 3 | 0.369 | | 0.35 | 0.35 | Styrene |
| Dioxin/Furan (2, 3, 7, 8-Tetrachlorodibenzo-p-dioxin) | ND | | 1.659 | | ND | ND | | 1.659 | | ND | 8.60E-12 | 3 | 0.369 | | 1.59E-09 | 1.6E-09 | Dioxin/Furan (2, 3, 7, 8-Tetrachlorodibenzo-p-dioxin) |
| Toluene | 3.36E-05 | 2 | 1.659 | | 0.028 | 3.36E-05 | 2 | 1.659 | | 0.028 | 9.20E-04 | 3 | 0.369 | | 0.17 | 0.23 | Toluene |
| 1, 1, 2-Trichloroethane | ND | | 1.659 | | ND | ND | | 1.659 | | ND | ND | | 0.369 | | ND | ND | 1, 1, 2-Trichloroethane |
| Trichloroethylene | ND | | 1.659 | | ND | ND | | 1.659 | | ND | ND | | 0.369 | | ND | ND | Trichloroethylene |
| Vinyl Chloride | ND | | 1.659 | | ND | ND | | 1.659 | | ND | 1.80E-05 | 3 | 0.369 | | 0.0033 | 0.0033 | Vinyl Chloride |
| m- & p-Xylene | ND | | 1.659 | | ND | ND | | 1.659 | | ND | ND | | 0.369 | | ND | ND | m- & p-Xylene |
| o-Xylene | ND | | 1.659 | | ND | ND | | 1.659 | | ND | 2.50E-05 | 3 | 0.369 | | 0.0046 | 0.0046 | o-Xylene |

Table B-6: Annual Emissions of Hazardous Air Pollutants from the Biomass Boiler, 10% Wood Scenario

| | Sugarcane Bagasse | | | | | Sorghum Bagasse | | | | | Wood | | | | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HAP | Emission Factor (lb/MMBtu) | Ref | Activity Factor ($10^{12}$ Btu/yr) | Control Efficiency (%) | Annual Emissions (TPY) | Emission Factor (lb/MMBtu) | Ref | Activity Factor ($10^{12}$ Btu/yr) | Control Efficiency (%) | Annual Emissions (TPY) | Emission Factor (lb/MMBtu) | Ref | Activity Factor ($10^{12}$ Btu/yr) | Control Efficiency (%) | Annual Emissions (TPY) | Maximum Emissions for All Fuels (TPY) | |
| **POMs** | | | | | | | | | | | | | | | | | **POMs** |
| 3-Methylcholanthrene | ND | | 1.659 | | ND | ND | | 1.659 | | ND | ND | 3 | 0.369 | | ND | ND | 3-Methylcholanthrene |
| Acenaphthene | ND | | 1.659 | | ND | ND | | 1.659 | | ND | 9.1E-07 | 3 | 0.369 | | 0.00017 | 0.00017 | Acenaphthene |
| Acenaphthylene | 7.94E-07 | 2 | 1.659 | | 0.00066 | 7.94E-07 | 2 | 1.659 | | 0.00066 | 5.0E-06 | 3 | 0.369 | | 0.00092 | 0.0022 | Acenaphthylene |
| Anthracene | 2.01E-07 | 2 | 1.659 | | 0.00017 | 2.01E-07 | 2 | 1.659 | | 0.00017 | 3.0E-06 | 3 | 0.369 | | 0.00055 | 0.00089 | Anthracene |
| Benzo (a) anthracene | 1.06E-06 | 2 | 1.659 | | 0.00088 | 1.06E-06 | 2 | 1.659 | | 0.00088 | 6.5E-08 | 3 | 0.369 | | 0.000012 | 0.0018 | Benzo (a) anthracene |
| Benzo(a)pyrene | 1.00E-06 | 2 | 1.659 | | 0.00083 | 1.00E-06 | 2 | 1.659 | | 0.00083 | 2.6E-06 | 3 | 0.369 | | 0.00048 | 0.0021 | Benzo(a)pyrene |
| Benzo(b)fluoranthene | 1.06E-06 | 2 | 1.659 | | 0.00088 | 1.06E-06 | 2 | 1.659 | | 0.00088 | 1.0E-07 | 3 | 0.369 | | 0.000018 | 0.0018 | Benzo(b)fluoranthene |
| Benzo(e)pyrene | 1.06E-06 | 2 | 1.659 | | 0.00088 | 1.06E-06 | 2 | 1.659 | | 0.00088 | 2.6E-09 | 3 | 0.369 | | 4.8E-07 | 0.0018 | Benzo(e)pyrene |
| Benzo(g,h,i)perylene | ND | | 1.659 | | ND | ND | | 1.659 | | ND | 9.3E-08 | 3 | 0.369 | | 0.000017 | 1.7E-05 | Benzo(g,h,i)perylene |
| Benzo(j,k)fluoranthene | 9.01E-07 | 2 | 1.659 | | 0.00075 | 9.01E-07 | 2 | 1.659 | | 0.00075 | 1.6E-07 | 3 | 0.369 | | 0.000029 | 0.0015 | Benzo(j,k)fluoranthene |
| Chrysene | 1.82E-06 | 2 | 1.659 | | 0.0015 | 1.82E-06 | 2 | 1.659 | | 0.0015 | 3.8E-08 | 3 | 0.369 | | 7.0E-06 | 0.0030 | Chrysene |
| Dibenzo(a,h)anthracene | ND | | 1.659 | | ND | ND | | 1.659 | | ND | 9.1E-09 | 3 | 0.369 | | 1.7E-06 | 1.7E-06 | Dibenzo(a,h)anthracene |
| Dimethylbenz(a)anthracene | ND | | 1.659 | | ND | ND | | 1.659 | | ND | ND | 3 | 0.369 | | ND | ND | Dimethylbenz(a)anthracene |
| Fluoranthene | 2.88E-06 | 2 | 1.659 | | 0.0024 | 2.88E-06 | 2 | 1.659 | | 0.0024 | 1.6E-06 | 3 | 0.369 | | 0.00 | 0.0051 | Fluoranthene |
| Fluorene | ND | | 1.659 | | ND | ND | | 1.659 | | ND | 3.4E-06 | 3 | 0.369 | | 6.3E-04 | 0.00063 | Fluorene |
| indeno(1,2,3-cd)pyrene | ND | | 1.659 | | ND | ND | | 1.659 | | ND | 8.7E-08 | 3 | 0.369 | | 1.6E-05 | 0.000016 | indeno(1,2,3-cd)pyrene |
| Naphthalene | 1.80E-05 | 2 | 1.659 | | 0.0149 | 1.80E-05 | 2 | 1.659 | | 0.015 | 9.7E-05 | 3 | 0.369 | | 1.8E-02 | 0.048 | Naphthalene |
| Perylene | ND | | 1.659 | | ND | ND | | 1.659 | | ND | 5.2E-10 | 3 | 0.369 | | 9.6E-08 | 9.6E-08 | Perylene |
| Phenanthrene | 2.71E-06 | 2 | 1.659 | | 0.0022 | 2.71E-06 | 2 | 1.659 | | 0.0022 | 7.0E-06 | 3 | 0.369 | | 0.0013 | 0.0058 | Phenanthrene |
| Pyrene | 2.71E-06 | 2 | 1.659 | | 0.0022 | 2.71E-06 | 2 | 1.659 | | 0.0022 | 3.7E-06 | 3 | 0.369 | | 0.00068 | 0.0052 | Pyrene |
| Total POMs** | | | | | 0.028 | | | | | 0.028 | | | | | 0.023 | 0.080 | Total POMs** |
| **MAXIMUM SINGLE HAP** | | | | | **2.90** | | | | | **3.32** | | | | | **0.81** | **6.85** | **MAXIMUM SINGLE HAP** |
| **TOTAL** | | | | | **5.65** | | | | | **8.60** | | | | | **4.00** | **18.26** | **TOTAL** |

UD = Undetected
ND = No Data available
[a] Assumed 90% control efficiency for all metals, except mercury for which zero control was assumed.
[b] For HCl a control efficiency of 92 percent was applied for all fuels.
[c] No HAP factors available for propane; therefore, factors for Natural Gas are used, assuming 1,020 Btu/scf for Natural Gas.

References
1. Based on the average of stack test results for New Hope Power Company Boilers A, B, and C (1999-2002) excluding 1999 wood test for Unit C.
2. Based on HAP Emissions for U.S. Sugar-Clewiston Boiler 7 - Geometric mean of three runs January 31, 2000.
3. Based on AP-42 emission factors for wood combustion (Section 1.6).
4. Based on the average of stack test result for boilers firing wood or a combination of wood and bagasse, 2004-2007. See Appendix B, Table B-4.
5. Based on HAP testing of bagasse fired boilers. Average of 18 runs for HCl. Emissions for $Cl_2$ based on AP-42 for wood firing and Appendix B, Table B-4, which shows 4% of HCl is emitted as $Cl_2$.
6. Based on the maximum of fuel analysis results for SRF sweet sorghum analysis conducted 9/9/2009, tested in US Sugar Clewiston Boiler No. 7.
7. Based on the ratio of wood emission factor for Chromium VI to Chromium.
8. Based on maximum chlorine content of sorghum (0.24% Cl or 0.32 lb/MMBtu as HCl) and assuming 75% inherent removal in ash. Chlorine emissions are 4% of HCl, based on AP-42 for wood firing and Appendix B, Table B-4.
**Sum of all POMs, unless emission factors are only listed for Total POMs, not individuals, and will be noted.

**Table B-7: Annual Emissions of Hazardous Air Pollutants from the Biomass Boiler, 30% Natural Gas Scenario**

| | Sugarcane Bagasse | | | | | Sorghum Bagasse | | | | | Natural Gas | | | | | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HAP | Emission Factor (lb/MMBtu) | Ref | Activity Factor ($10^{12}$ Btu/yr) | Control Efficiency (%) | Annual Emissions (TPY) | Emission Factor (lb/MMBtu) | Ref | Activity Factor ($10^{12}$ Btu/yr) | Control Efficiency (%) | Annual Emissions (TPY) | Emission Factor (lb/$10^6$ scf) | Emission Factor (lb/MMBtu) | Ref | Activity Factor ($10^{12}$ Btu/yr) | Control Efficiency (%) | Annual Emissions (TPY) | Maximum Emissions for All Fuels (TPY) | |
| **Biomass Boiler** | | | | | | | | | | | | | | | | | | |
| Acetaldehyde | UD | 2 | 1.215 | | UD | UD | 2 | 1.215 | | UD | ND | ND | | 1.042 | | ND | ND | Acetaldehyde |
| Acetophenone | ND | | 1.215 | | ND | ND | | 1.215 | | ND | ND | ND | | 1.042 | | ND | ND | Acetophenone |
| Acrolein | UD | 2 | 1.215 | | UD | UD | 2 | 1.215 | | UD | ND | ND | | 1.042 | | ND | ND | Acrolein |
| Antimony | ND | | 1.215 | | ND | ND | | 1.215 | | ND | ND | ND | | 1.042 | | ND | ND | Antimony |
| Arsenic[a] | 2.05E-05 | 5 | 1.215 | 90 | 0.0012 | 2.05E-05 | 5 | 1.215 | 90 | 0.0012 | 2.00E-04 | 1.96E-07 | 3 | 1.042 | 90 | 1.02E-05 | 0.0025 | Arsenic[a] |
| Benzene | 8.43E-04 | 2 | 1.215 | | 0.51 | 8.43E-04 | 2 | 1.215 | | 0.51 | 2.10E-03 | 2.06E-06 | 3 | 1.042 | | 0.0011 | 1.025 | Benzene |
| Beryllium[a] | 3.85E-05 | 5 | 1.215 | 90 | 0.0023 | 3.85E-05 | 5 | 1.215 | 90 | 0.0023 | 1.20E-05 | 1.18E-08 | 3 | 1.042 | 90 | 6.13E-07 | 0.0047 | Beryllium[a] |
| bis(2ethylhexyl)phthalate | 4.20E-04 | 2 | 1.215 | | 0.26 | 4.20E-04 | 2 | 1.215 | | 0.26 | ND | ND | | 1.042 | | ND | 0.51 | bis(2ethylhexyl)phthalate |
| Cadmium[a] | 3.33E-05 | 5 | 1.215 | 90 | 0.0020 | 3.33E-05 | 5 | 1.215 | 90 | 0.0020 | 1.10E-03 | 1.08E-06 | 3 | 1.042 | 90 | 5.62E-05 | 0.0041 | Cadmium[a] |
| Carbon Disulfide | ND | | 1.215 | | ND | ND | | 1.215 | | ND | ND | ND | | 1.042 | | ND | ND | Carbon Disulfide |
| Carbon Tetrachloride | ND | | 1.215 | | ND | ND | | 1.215 | | ND | ND | ND | | 1.042 | | ND | ND | Carbon Tetrachloride |
| Chlorine | 0.00014 | 4 | 1.215 | | 0.085 | 0.0032 | 7 | 1.215 | | 1.94 | ND | ND | | 1.042 | | ND | 2.03 | Chlorine |
| Chlorobenzene | ND | | 1.215 | | ND | ND | | 1.215 | | ND | ND | ND | | 1.042 | | ND | ND | Chlorobenzene |
| Chloroform | ND | | 1.215 | | ND | ND | | 1.215 | | ND | ND | ND | | 1.042 | | ND | ND | Chloroform |
| Chromium[a] | 1.79E-03 | 5 | 1.215 | 90 | 0.11 | 1.79E-03 | 5 | 1.215 | 90 | 0.11 | 1.40E-03 | 1.37E-06 | 3 | 1.042 | 90 | 7.15E-05 | 0.22 | Chromium[a] |
| Chromium+6 | 3.17E-04 | 6 | 1.215 | 90 | 0.019 | 3.17E-04 | 6 | 1.215 | 90 | 0.019 | ND | ND | | 1.042 | 90 | ND | 0.039 | Chromium+6 |
| Cobalt | ND | | 1.215 | | ND | ND | | 1.215 | | ND | 8.40E-05 | 8.24E-08 | 3 | 1.042 | | 4.29E-05 | 4.29E-05 | Cobalt |
| m&p-Cresol | ND | | 1.215 | | ND | ND | | 1.215 | | ND | ND | ND | | 1.042 | | ND | ND | m&p-Cresol |
| Cumene | ND | | 1.215 | | ND | ND | | 1.215 | | ND | ND | ND | | 1.042 | | ND | ND | Cumene |
| Dibenzofurans | ND | | 1.215 | | ND | ND | | 1.215 | | ND | ND | ND | | 1.042 | | ND | ND | Dibenzofurans |
| Dibutylphthalate | ND | | 1.215 | | ND | ND | | 1.215 | | ND | ND | ND | | 1.042 | | ND | ND | Dibutylphthalate |
| 1,4-Dichlorobenzene(p) | ND | | 1.215 | | ND | ND | | 1.215 | | ND | 1.20E-03 | 1.18E-06 | 3 | 1.042 | | 0.00061 | 0.00061 | 1,4-Dichlorobenzene(p) |
| Ethylbenzene | ND | | 1.215 | | ND | ND | | 1.215 | | ND | ND | ND | | 1.042 | | ND | ND | Ethylbenzene |
| Formaldehyde | 1.13E-03 | 2 | 1.215 | | 0.69 | 1.13E-03 | 2 | 1.215 | | 0.69 | 7.50E-02 | 7.35E-05 | 3 | 1.042 | | 0.038 | 1.41 | Formaldehyde |
| Hexane | ND | | 1.215 | | ND | ND | | 1.215 | | ND | 1.80E+00 | 1.76E-03 | 3 | 1.042 | | 0.92 | 0.92 | Hexane |
| Hydrogen Chloride[b] | 0.0035 | 4 | 1.215 | 0 | 2.13 | 0.080 | 7 | 1.215 | 95 | 2.43 | ND | ND | | 1.042 | | ND | 4.56 | Hydrogen Chloride[b] |
| Hydrogen Fluoride | 3.01E-04 | 1 | 1.215 | 92 | 0.015 | 3.01E-04 | 1 | 1.215 | 92 | 0.015 | ND | ND | | 1.042 | | ND | 0.029 | Hydrogen Fluoride |
| Lead-Total[a] | 9.61E-04 | 5 | 1.215 | 90 | 0.058 | 9.61E-04 | 5 | 1.215 | 90 | 0.058 | 5.00E-04 | 4.90E-07 | 3 | 1.042 | 90 | 2.55E-05 | 0.12 | Lead-Total[a] |
| Manganese[a] | 2.31E-03 | 5 | 1.215 | 90 | 0.14 | 2.31E-03 | 5 | 1.215 | 90 | 0.14 | 3.80E-04 | 3.73E-07 | 3 | 1.042 | 90 | 1.94E-05 | 0.28 | Manganese[a] |
| Mercury[a] | 1.38E-05 | 5 | 1.215 | | 0.0084 | 1.38E-05 | 5 | 1.215 | | 0.0084 | 2.60E-04 | 2.55E-07 | 3 | 1.042 | | 0.00013 | 0.017 | Mercury[a] |
| Methanol | UD | 2 | 1.215 | | UD | UD | 2 | 1.215 | | UD | ND | ND | | 1.042 | | ND | ND | Methanol |
| Methyl Isobutyl Ketone | ND | | 1.215 | | ND | ND | | 1.215 | | ND | ND | ND | | 1.042 | | ND | ND | Methyl Isobutyl Ketone |
| Methylene Chloride | ND | | 1.215 | | ND | ND | | 1.215 | | ND | ND | ND | | 1.042 | | ND | ND | Methylene Chloride |
| Nickel[a] | 1.10E-03 | 5 | 1.215 | 90 | 0.067 | 1.10E-03 | 5 | 1.215 | 90 | 0.067 | 2.10E-03 | 2.06E-06 | 3 | 1.042 | 90 | 0.00011 | 0.13 | Nickel[a] |
| 4-Nitrophenol | ND | | 1.215 | | ND | ND | | 1.215 | | ND | ND | ND | | 1.042 | | ND | ND | 4-Nitrophenol |
| Pentachlorophenol (PCP) | ND | | 1.215 | | ND | ND | | 1.215 | | ND | ND | ND | | 1.042 | | ND | ND | Pentachlorophenol (PCP) |
| Phenols | 1.12E-05 | 2 | 1.215 | | 0.0068 | 1.12E-05 | 2 | 1.215 | | 0.0068 | ND | ND | | 1.042 | | ND | 0.014 | Phenols |
| Phosphorus | ND | | 1.215 | | ND | ND | | 1.215 | | ND | ND | ND | | 1.042 | | ND | ND | Phosphorus |
| Propionaldehyde | ND | | 1.215 | | ND | ND | | 1.215 | | ND | ND | ND | | 1.042 | | ND | ND | Propionaldehyde |
| Selenium[a] | 6.41E-06 | 5 | 1.215 | 90 | 0.0039 | 6.41E-06 | 5 | 1.215 | 90 | 0.0039 | 2.40E-05 | 2.35E-08 | 3 | 1.042 | 90 | 1.23E-06 | 0.0078 | Selenium[a] |
| Styrene | ND | | 1.215 | | ND | ND | | 1.215 | | ND | ND | ND | | 1.042 | | ND | ND | Styrene |
| Dioxin/Furan (2, 3, 7, 8-Tetrachlorodibenzo-p-dioxin) | ND | | 1.215 | | ND | ND | | 1.215 | | ND | ND | ND | | 1.042 | | ND | ND | Dioxin/Furan (2, 3, 7, 8-Tetrachlorodibenzo-p-dioxin) |
| Toluene | 3.36E-05 | 2 | 1.215 | | 0.020 | 3.36E-05 | 2 | 1.215 | | 0.020 | 3.40E-03 | 3.33E-06 | 3 | 1.042 | | 0.0017 | 0.043 | Toluene |
| 1, 1, 2-Trichloroethane | ND | | 1.215 | | ND | ND | | 1.215 | | ND | ND | ND | | 1.042 | | ND | ND | 1, 1, 2-Trichloroethane |
| Trichloroethylene | ND | | 1.215 | | ND | ND | | 1.215 | | ND | ND | ND | | 1.042 | | ND | ND | Trichloroethylene |
| Vinyl Chloride | ND | | 1.215 | | ND | ND | | 1.215 | | ND | ND | ND | | 1.042 | | ND | ND | Vinyl Chloride |
| m- & p-Xylene | ND | | 1.215 | | ND | ND | | 1.215 | | ND | ND | ND | | 1.042 | | ND | ND | m- & p-Xylene |
| o-Xylene | ND | | 1.215 | | ND | ND | | 1.215 | | ND | ND | ND | | 1.042 | | ND | ND | o-Xylene |

Table B-7: Annual Emissions of Hazardous Air Pollutants from the Biomass Boiler, 30% Natural Gas Scenario

| | Sugarcane Bagasse | | | | | Sorghum Bagasse | | | | | Natural Gas | | | | | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HAP | Emission Factor (lb/MMBtu) | Ref | Activity Factor ($10^{12}$ Btu/yr) | Control Efficiency (%) | Annual Emissions (TPY) | Emission Factor (lb/MMBtu) | Ref | Activity Factor ($10^{12}$ Btu/yr) | Control Efficiency (%) | Annual Emissions (TPY) | Emission Factor (lb/$10^6$ scf) | Emission Factor (lb/MMBtu) | Ref | Activity Factor ($10^{12}$ Btu/yr) | Control Efficiency (%) | Annual Emissions (TPY) | Maximum Emissions for All Fuels (TPY) | |
| POMs | | | | | | | | | | | | | | | | | | POMs |
| 3-Methylcholanthrene | ND | | 1.215 | | ND | ND | | 1.215 | | ND | 1.80E-06 | 1.8E-09 | 3 | 1.042 | | 9.19E-07 | 9.19E-07 | 3-Methylcholanthrene |
| Acenaphthene | ND | | 1.215 | | ND | ND | | 1.215 | | ND | 1.80E-06 | 1.8E-09 | 3 | 1.042 | | 9.19E-07 | 9.19E-07 | Acenaphthene |
| Acenaphthylene | 7.94E-07 | 2 | 1.215 | | 0.00048 | 7.94E-07 | 2 | 1.215 | | 0.00048 | 1.80E-06 | 1.8E-09 | 3 | 1.042 | | 9.19E-07 | 0.0010 | Acenaphthylene |
| Anthracene | 2.01E-07 | 2 | 1.215 | | 0.00012 | 2.01E-07 | 2 | 1.215 | | 0.00012 | 2.40E-06 | 2.4E-09 | 3 | 1.042 | | 1.23E-06 | 0.00025 | Anthracene |
| Benzo (a) anthracene | 1.06E-06 | 2 | 1.215 | | 0.00064 | 1.06E-06 | 2 | 1.215 | | 0.00064 | 1.80E-06 | 1.8E-09 | 3 | 1.042 | | 9.19E-07 | 0.0013 | Benzo (a) anthracene |
| Benzo(a)pyrene | 1.00E-06 | 2 | 1.215 | | 0.00061 | 1.00E-06 | 2 | 1.215 | | 0.00061 | 1.20E-06 | 1.2E-09 | 3 | 1.042 | | 6.13E-07 | 0.0012 | Benzo(a)pyrene |
| Benzo(b)fluoranthene | 1.06E-06 | 2 | 1.215 | | 0.00064 | 1.06E-06 | 2 | 1.215 | | 0.00064 | 1.80E-06 | 1.8E-09 | 3 | 1.042 | | 9.19E-07 | 0.0013 | Benzo(b)fluoranthene |
| Benzo(e)pyrene | 1.06E-06 | 2 | 1.215 | | 0.00064 | 1.06E-06 | 2 | 1.215 | | 0.00064 | ND | ND | | 1.042 | | ND | 0.0013 | Benzo(e)pyrene |
| Benzo(g,h,i)perylene | ND | | 1.215 | | ND | ND | | 1.215 | | ND | 1.20E-06 | 1.2E-09 | 3 | 1.042 | | 6.13E-07 | 6.13E-07 | Benzo(g,h,i)perylene |
| Benzo(j,k)fluoranthene | 9.01E-07 | 2 | 1.215 | | 0.00055 | 9.01E-07 | 2 | 1.215 | | 0.00055 | 1.80E-06 | 1.8E-09 | 3 | 1.042 | | 9.19E-07 | 0.0011 | Benzo(j,k)fluoranthene |
| Chrysene | 1.82E-06 | 2 | 1.215 | | 0.0011 | 1.82E-06 | 2 | 1.215 | | 0.0011 | 1.80E-06 | 1.8E-09 | 3 | 1.042 | | 9.19E-07 | 0.0022 | Chrysene |
| Dibenzo(a,h)anthracene | ND | | 1.215 | | ND | ND | | 1.215 | | ND | 1.20E-06 | 1.2E-09 | 3 | 1.042 | | 6.13E-07 | 6.13E-07 | Dibenzo(a,h)anthracene |
| Dimethylbenz(a)anthracene | ND | | 1.215 | | ND | ND | | 1.215 | | ND | ND | ND | | 1.042 | | ND | ND | Dimethylbenz(a)anthracene |
| Fluoranthene | 2.88E-06 | 2 | 1.215 | | 0.0017 | 2.88E-06 | 2 | 1.215 | | 0.0017 | 3.00E-06 | 2.9E-09 | 3 | 1.042 | | 1.53E-06 | 0.0035 | Fluoranthene |
| Fluorene | ND | | 1.215 | | ND | ND | | 1.215 | | ND | 2.80E-06 | 2.7E-09 | 3 | 1.042 | | 1.43E-06 | 1.43E-06 | Fluorene |
| indeno(1,2,3-cd)pyrene | ND | | 1.215 | | ND | ND | | 1.215 | | ND | 1.80E-06 | 1.8E-09 | 3 | 1.042 | | 9.19E-07 | 9.19E-07 | indeno(1,2,3-cd)pyrene |
| Naphthalene | 1.80E-05 | 2 | 1.215 | | 0.011 | 1.80E-05 | 2 | 1.215 | | 0.011 | 6.10E-04 | 6.0E-07 | 3 | 1.042 | | 3.11E-04 | 0.022 | Naphthalene |
| Perylene | ND | | 1.215 | | ND | ND | | 1.215 | | ND | ND | ND | | 1.042 | | ND | ND | Perylene |
| Phenanthrene | 2.71E-06 | 2 | 1.215 | | 0.0016 | 2.71E-06 | 2 | 1.215 | | 0.0016 | 1.70E-05 | 1.7E-08 | 3 | 1.042 | | 8.68E-06 | 0.0033 | Phenanthrene |
| Pyrene | 2.71E-06 | 2 | 1.215 | | 0.0016 | 2.71E-06 | 2 | 1.215 | | 0.0016 | 5.00E-06 | 4.9E-09 | 3 | 1.042 | | 2.55E-06 | 0.0033 | Pyrene |
| Total POMs** | | | | | 0.021 | | | | | 0.021 | | | | | | 3.36E-04 | 0.042 | Total POMs** |
| **MAXIMUM SINGLE HAP** | | | | | **2.13** | | | | | **2.43** | | | | | | **0.92** | **4.56** | **MAXIMUM SINGLE HAP** |
| **TOTAL** | | | | | **4.14** | | | | | **6.30** | | | | | | **0.96** | **11.40** | **TOTAL** |

UD = Undetected

ND = No Data available

[a] Assumed 90% control efficiency for all metals, except mercury for which zero control was assumed.

[b] For HCl a control efficiency of 92 percent was applied for all fuels.

[c] No HAP factors available for propane; therefore, factors for Natural Gas are used, assuming 1,020 Btu/scf for Natural Gas.

References

1. Based on the average of stack test results for New Hope Power Company Boilers A, B, and C (1999-2002) excluding 1999 wood test for Unit C.
2. Based on HAP Emissions for U.S. Sugar-Clewiston Boiler 7 - Geometric mean of three runs January 31, 2000.
3. Based on AP-42 emission factors for natural gas combustion (Section 1.4).
4. Based on HAP testing of bagasse fired boilers. Average of 18 runs for HCl. Emissions for $Cl_2$ based on AP-42 for wood firing and Appendix B, Table B-4, which shows 4% of HCl is emitted as $Cl_2$.
5. Based on the maximum of fuel analysis results for SRF sweet sorghum analysis conducted 9/9/2009, tested in US Sugar Clewiston Boiler No. 7.
6. Based on the ratio of wood emission factor for Chromium VI to Chromium.
7. Based on maximum chlorine content of sorghum (0.24% Cl or 0.32 lb/MMBtu as HCl) and assuming 75% inherent removal in ash. Chlorine emissions are 4% of HCl, based on AP-42 for wood firing and Appendix B, Table B-4.

**Sum of all POMs, unless emission factors are only listed for Total POMs, not individuals, and will be noted.

# APPENDIX C

# FUGITIVE EMISSION ESTIMATES FOR WIND EROSION AND VEHICULAR TRAFFIC

**Table C-1: Estimation of Total Projected PM Emission Rate for Wind Erosion, Biomass Storage Pile**

| Parameters | Wind Erosion - Biomass Storage Pile | | | |
|---|---|---|---|---|
| **Storage Pile Data** | Annual | | Daily[f] | |
| Material Type | Bagasse | Wood | Bagasse | Wood |
| Pile Description (shape) | Varied | Varied | Varied | Varied |
| No. Piles | 1 | 1 | 1 | 1 |
| Size, $ft^2$ | 75,000 [a] | 25,000 [a] | 75,000 [a] | 25,000 [a] |
| Size, acres | 1.72 | 0.57 | 1.72 | 0.57 |
| **General/ Site Characteristics** | | | | |
| Days of precipitation greater than or equal to 0.25 mm (p) within a year | 120 [b] | 120 [b] | 0 [b] | 0 [b] |
| Time (%) that unobstructed wind speed exceeds 5.4 m/s | 12 [c] | 12 [c] | 37 [c] | 37 [c] |
| Time (hr/day) that unobstructed wind speed exceeds 5.4 m/s | NA | NA | 9 [f] | 9 [f] |
| Silt content (s), % | 0.1 [d] | 3.9 [d] | 0.1 [d] | 3.9 [d] |
| Particle size multiplier, PM (k) | 1.00 | 1.00 | 1.00 | 1.00 |
| Particle size multiplier, $PM_{10}$ (k) | 0.50 | 0.50 | 0.50 | 0.50 |
| Emission Control Data | | | | |
| Emission control method | Watering | Watering | Watering | Watering |
| Emission control removal efficiency, % | 50 | 50 | 50 | 50 |
| **Emission Factor (EF) Equation** | | | | |
| Uncontrolled EF (UEF) Equation | UEF (lb/day/acre) = k x 1.7 x (s/1.5) x ((365 - p)/235) x (f/15) | | | |
| Controlled (Final) EF (CEF) Equation | CEF (lb/day/acre) = UEF (lb/day/acre) x (100 - Removal efficiency (%)) | | | |
| **Calculated PM Emission Factor (EF)** | | | | |
| Uncontrolled EF, lb/day/acre | 0.10 | 3.79 | 0.43 | 16.93 |
| Controlled EF, lb/day/acre | 0.049 | 1.90 | 0.22 | 8.47 |
| **Calculated $PM_{10}$ Emission Factor (EF)** | | | | |
| Uncontrolled EF, lb/day/acre | 0.049 | 1.90 | 0.22 | 8.47 |
| Controlled EF, lb/day/acre | 0.024 | 0.95 | 0.11 | 4.23 |
| **Calculated $PM_{2.5}$ Emission Factor (EF)[e]** | | | | |
| Uncontrolled EF, lb/day/acre | 0.049 | 1.90 | 0.22 | 8.47 |
| Controlled EF, lb/day/acre | 0.024 | 0.948 | 0.11 | 4.23 |
| **Estimated Emission Rate (ER)** | | | | |
| **PM** | 0.015 TPY | 0.20 TPY | 0.37 lb/day<br>0.042 lb/hr | 4.86 lb/day<br>0.54 lb/hr |
| **$PM_{10}$** | 0.008 TPY | 0.10 TPY | 0.19 lb/day<br>0.021 lb/hr | 2.43 lb/day<br>0.27 lb/hr |
| **$PM_{2.5}$** | 0.008 TPY | 0.10 TPY | 0.19 lb/day<br>0.021 lb/hr | 2.43 lb/day<br>0.27 lb/hr |

Source: USEPA, 1992 (Fugitive Dust Background and Technical Information Document for Best Available Control Measures, Section 2.3.1.3.3, Wind Emissions from Continuously Active Piles)

[a] Bagasse storage pile based on plot plan.

[b] Data from AP-42 Figure 13.2.2-1

[c] Average from 2001 - 2005 Fort Myers Meteorological data. A daily percentage was calculated based on the 90th percentile of the daily averages for all five years.

[d] Data from silt sampling conducted at a similar facility located in Palm Beach County.

[e] $PM_{2.5}$ assumed to be equal to $PM_{10}$.

[f] Based on the average over 5 years (2001 - 2005) of the 90th percentile value for the number of hours to exceed 5.4 m/s in one day. This value is approximately 9 hours per day and was used to calculate the daily rate.

**Table C-2: Estimation of PM Emission Rates for Biomass Pile Maintenance and Reclaim Conveyor Loading by Frontend Loader**

| **Parameters** | | **Frontend-Loader Pile Maintenance** | |
|---|---|---|---|
| **Vehicle Data** | | **Bagasse** | **Wood** |
| Vehicle weight (W), (tons) | | | |
| | Average (tons) | 20.0 [a] | 20.0 [a] |
| Operating time, hours per vehicle | Daily | 6 | 6 |
| days per vehicle | Annual | 365 | 365 |
| Average Vehicle Speed | miles/hr | 5 | 5 |
| Number of Vehicles | | 1 | 1 |
| VMT (Average vehicle speed x travel time x number of vehicles) | | | |
| | Daily | 30 | 30 |
| | Annual | 10,950 [a] | 10,950 [a] |
| **General/ Site Characteristics** | | | |
| Days of precipitation greater than or | Daily | 0 | 0 |
| equal to 0.254 mm (p) | Annual | 120 [b] | 120 [b] |
| Silt content (s), (%) | | 0.1 [c] | 3.9 [c] |
| Particle size multiplier (lb/VMT) | k (PM) | 4.9 | 4.9 |
| | k ($PM_{10}$) | 1.5 | 1.5 |
| | k ($PM_{2.5}$) | 0.15 | 0.15 |
| Coefficients for silt content- PM | a | 0.7 | 0.7 |
| | b | 0.45 | 0.45 |
| Coefficients for silt content- $PM_{10}$ / $PM_{2.5}$ | a | 0.9 | 0.9 |
| | b | 0.45 | 0.45 |
| Emission Control Data | | | |
| Emission control method | | Enclosure/Watering | Enclosure/Watering |
| Emission control removal efficiency , (%) | | 75 | 75 |
| **Emission Factor (EF) Equation** [d] | | | |
| Uncontrolled EF (UEF) Equation | UEF(lb/VMT) = k (lb/VMT) x $(s/12)^a$ x $(W)/3)^b$ x [(365 - p)/365] | | |
| Controlled EF (CEF) Equation | CEF(lb/VMT) = UEF (lb/VMT) x (100 - Removal efficiency (%)) | | |
| **Calculated PM Emission Factor (EF)** | | | |
| Daily | Uncontrolled EF, lb/VMT | 0.40 | 5.24 |
| | Controlled EF, lb/VMT | 0.10 | 1.31 |
| Annual | Uncontrolled EF, lb/VMT | 0.27 | 3.52 |
| | Controlled EF, lb/VMT | 0.07 | 0.88 |
| **Calculated $PM_{10}$** Emission Factor (EF) | | | |
| Daily | Uncontrolled EF, lb/VMT | 0.047 | 1.28 |
| | Controlled EF, lb/VMT | 0.012 | 0.32 |
| Annual | Uncontrolled EF, lb/VMT | 0.032 | 0.86 |
| | Controlled EF, lb/VMT | 0.008 | 0.21 |
| **Calculated $PM_{2.5}$** Emission Factor (EF) | | | |
| Daily | Uncontrolled EF, lb/VMT | 0.0047 | 0.13 |
| | Controlled EF, lb/VMT | 0.0012 | 0.032 |
| Annual | Uncontrolled EF, lb/VMT | 0.0032 | 0.086 |
| | Controlled EF, lb/VMT | 0.0008 | 0.021 |
| **Estimated Emission Rate (ER)** | | | |
| **PM** (lb/day) | Daily | 3.02 | 39.29 |
| (TPY) | Annual | 0.37 | 4.81 |
| **$PM_{10}$** (lb/day) | Daily | 0.36 | 9.61 |
| (TPY) | Annual | 0.044 | 1.18 |
| **$PM_{2.5}$** (lb/day) | Daily | 0.036 | 0.96 |
| (TPY) | Annual | 0.0044 | 0.12 |

Source: USEPA, 2006 (AP-42, Section 13.2.2 Unpaved Roads).

[a] Data from similar application.

[b] From AP-42 Figure 13.2.2-1

[c] Data from silt sampling conducted at a similar facility located in Palm Beach County.

[d] AP-42 emission factor provides emission factor as pounds per vehicle mile traveled (lb/VMT).

**Table C-3: Estimation of Total Existing PM Emission Rates for Biomass Pile Maintenance, Bulldozer**

| Parameters | | Bulldozer Pile Maintenance | |
|---|---|---|---|
| **Operating Data** | | **Bagasse** | **Wood** |
| Operating time, hours | Daily | 6 | 6 |
| | Annual | 2,190 | 2,190 |
| days | Annual | 365 | 365 |
| Number of Vehicles | | 1 | 1 |
| **General/ Site Characteristics** | | | |
| Material Moisture Content (M), (%) | | 50 [a] | 40 [a] |
| Silt content (s), (%) | | 0.1 [a] | 3.9 [a] |
| Scaling Factors | k ($PM_{10}$) | 0.75 | 0.75 |
| | k ($PM_{2.5}$) | 0.022 | 0.022 |
| Emission Control Data | | | |
| Emission control method | | Partial Enclosure/Watering | Partial Enclosure/Watering |
| Emission control removal efficiency , (%) | | 75 | 75 |
| **Emission Factor (EF) Equation** [b] | | | |
| Uncontrolled EF (UEF) Equation (TSP ≤30μm) | UEF(lb/hr) =$78.4(s)^{1.2}/M^{1.3}$ | | |
| PM (≤15 μm) | UEF (lb/hr) = $18.6(s)^{1.5}/(M)^{1.4}$ | | |
| Controlled EF (CEF) Equation | CEF(lb/VMT) = UEF (lb/VMT) x (100 - Removal efficiency (%)) | | |
| **Calculated PM Emission Factor (EF)** | | | |
| Uncontrolled EF, lb/hr | | 0.031 | 3.32 |
| Controlled EF, lb/hr | | 0.008 | 0.83 |
| **Calculated $PM_{10}$ Emission Factor (EF)** | | | |
| Uncontrolled EF, lb/hr | | 0.0018 | 0.61 |
| Controlled EF, lb/hr | | 0.00046 | 0.15 |
| **Calculated $PM_{2.5}$ Emission Factor (EF)** | | | |
| Uncontrolled EF, lb/hr | | 0.00067 | 0.073 |
| Controlled EF, lb/hr | | 0.00017 | 0.018 |
| **Estimated Emission Rate (ER)** | | | |
| **PM** (lb/day) | Daily | 0.046 | 4.98 |
| (TPY) | Annual | 0.008 | 0.91 |
| **$PM_{10}$** (lb/day) | Daily | 0.0028 | 0.92 |
| (TPY) | Annual | 0.0005 | 0.17 |
| **$PM_{2.5}$** (lb/day) | Daily | 0.0010 | 0.11 |
| (TPY) | Annual | 0.00018 | 0.020 |

Source: USEPA, 1998 (AP-42, Section 11.9; Table 11.9-1 - Bulldozing, Coal).

[a] Data from silt sampling conducted at a similar facility located in Palm Beach County.

[b] AP-42 emission factor provides emission factor as pounds per hour (lb/hr).

**Table C-4: Estimation of PM Emission Factors and Rates for Truck Traffic on Paved Roads**

| Parameters | | Truck | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Vehicle Data** | | **Sugarcane** | **Sweet Sorghum** | **Wood** | **Ash** | **Ethanol** | **Denaturant / Gasoline** | **Lime/DSI Reagent** |
| Vehicle weight (W) | Average (tons) | 17.5 [a] | 17.5 [a] | 17.5 [a] | 17.5 [a] | 21.0 [a] | 21.0 [a] | 17.5 [a] |
| Travel Distance | miles | 0.85 | 0.85 | 0.85 | 0.85 | 0.41 | 0.41 | 0.85 |
| Number of vehicles | trucks/day | 82 | 82 | 5 | 2 | 11 | 1 | 1 |
| | trucks/year | 30,000 [b] | 30,000 [b] | 1,735 [b] | 865 [b] | 4,000 [b] | 180 [b] | 55 [b] |
| VMT (travel distance x number of vehicles) | Daily | 70 | 70 | 4 | 2 | 4 | 0.41 | 1 |
| | Annual | 25,500 | 25,500 | 1,475 | 735 | 1,640 | 74 | 47 |
| **General/ Site Characteristics** | | | | | | | | |
| Days of precipitation greater than or equal to 0.254 mm (P) | Annual | 120 [c] | 120 [c] | 120 [c] | 120 [c] | 120 [c] | 120 [c] | 120 [c] |
| Silt loading (sL), ($g/m^2$) | | 1.1 [d] | 1.1 [d] | 1.1 [d] | 1.1 [d] | 1.1 [d] | 1.1 [d] | 1.1 [d] |
| Particle size multiplier (lb/VMT) | k (PM) | 0.011 | 0.011 | 0.011 | 0.011 | 0.011 | 0.011 | 0.011 |
| | k ($PM_{10}$) | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 |
| | k ($PM_{2.5}$) | 0.00054 | 0.00054 | 0.00054 | 0.00054 | 0.00054 | 0.00054 | 0.00054 |
| Number of days in averaging period | N | 365 | 365 | 365 | 365 | 365 | 365 | 365 |
| Operating time, hours | Daily | 24 | 24 | 24 | 24 | 24 | 24 | 24 |
| | Annual | 8,760 | 8,760 | 8,760 | 8,760 | 8,760 | 8,760 | 8,760 |
| **Emission Control Data** | | | | | | | | |
| Emission control method | | Watering/ Sweeping | Watering/ Sweeping | Watering/ Sweeping | Watering/ Sweeping | Watering/ Sweeping | Watering/ Sweeping | Watering/ Sweeping |
| Emission control removal efficiency , (%) | | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| **Emission Factor (EF) Equation** [e] | | | | | | | | |
| Uncontrolled EF (UEF) Equation | UEF(lb/VMT) = [k (lb/VMT) x $(SL/2)^{0.91}$ x $(W)^{1.02}$](1-(P/4N)) | | | | | | | |
| Controlled EF (CEF) Equation | CEF(lb/VMT) = UEF (lb/VMT) x (100 - Removal efficiency (%)) | | | | | | | |
| **Calculated PM Emission Factor (EF)** | | | | | | | | |
| Uncontrolled EF, lb/VMT | | 0.11 | 0.11 | 0.11 | 0.11 | 0.13 | 0.13 | 0.11 |
| Controlled EF, lb/VMT | | 0.055 | 0.06 | 0.06 | 0.06 | 0.07 | 0.07 | 0.06 |
| **Calculated $PM_{10}$ Emission Factor (EF)** | | | | | | | | |
| Uncontrolled EF, lb/VMT | | 0.022 | 0.022 | 0.022 | 0.022 | 0.027 | 0.027 | 0.022 |
| Controlled EF, lb/VMT | | 0.011 | 0.011 | 0.011 | 0.011 | 0.013 | 0.013 | 0.011 |
| **Calculated $PM_{2.5}$ Emission Factor (EF)** | | | | | | | | |
| Uncontrolled EF, lb/VMT | | 0.0054 | 0.0054 | 0.0054 | 0.0054 | 0.0065 | 0.0065 | 0.0054 |
| Controlled EF, lb/VMT | | 0.0027 | 0.0027 | 0.0027 | 0.0027 | 0.0033 | 0.0033 | 0.0027 |
| **Estimated Emission Rate (ER)** | | | | | | | | |
| **PM** (lb/day) | Daily | 3.86 | 3.86 | 0.22 | 0.11 | 0.30 | 0.027 | 0.047 |
| (TPY) | Annual | 0.70 | 0.70 | 0.041 | 0.020 | 0.055 | 0.0025 | 0.00129 |
| **$PM_{10}$** (lb/day) | Daily | 0.77 | 0.77 | 0.045 | 0.022 | 0.060 | 0.0055 | 0.0094 |
| (TPY) | Annual | 0.14 | 0.14 | 0.0081 | 0.0041 | 0.011 | 0.00049 | 0.00026 |
| **$PM_{2.5}$** (lb/day) | Daily | 0.19 | 0.19 | 0.0109 | 0.0055 | 0.015 | 0.0013 | 0.0023 |
| (TPY) | Annual | 0.035 | 0.035 | 0.0020 | 0.0010 | 0.0027 | 0.00012 | 0.000064 |

Source: USEPA, 2011 (AP-42, Section 13.2.1 Paved Roads).

[a] Based on "fleet" average weight. Each loaded truck for materials handling has an approximate weight of 30 tons and each unloaded truck has approximate weight of 5 tons, for a fleet average weight of 17.5 tons. This was increased by a factor of safety of 20% for ethanol process trucks.

[b] Refer to Table 2-25 for calculations.

[c] From AP-42 Figure 13.2.2-1.

[d] Data from silt sampling conducted at a similar facility located in Palm Beach County.

[e] AP-42 provides emission factor as pounds per vehicle mile traveled (lb/VMT).

Table C-5: Maximum Daily Fugitive Dust Emissions for the Modeling Analysis

| SOURCE | TYPE OF OPERATION | M MOISTURE CONTENT [a] (%) | U WIND SPEED [b] (MPH) | UNCONTROLLED PM EMISSION FACTOR (LB/TON) [c] | UNCONTROLLED $PM_{10}$ EMISSION FACTOR (LB/TON) [c] | UNCONTROLLED $PM_{2.5}$ EMISSION FACTOR (LB/TON) [c] | CONTROL TYPE | CONTROL EFFICIENCY (%) | CONTROLLED PM EMISSION FACTOR (LB/TON) | CONTROLLED $PM_{10}$ EMISSION FACTOR (LB/TON) | CONTROLLED $PM_{2.5}$ EMISSION FACTOR (LB/TON) | ACTIVITY FACTOR | MAXIMUM SHORT-TERM EMISSIONS PM (TSP) (LB/DAY) | PM (TSP) (LB/HR) | $PM_{10}$ (LB/DAY) | $PM_{10}$ (LB/HR) | $PM_{2.5}$ (LB/DAY) | $PM_{2.5}$ (LB/HR) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BIOMASS DELIVERIES | | | | | | | | | | | | | | | | | | |
| SUGARCANE TRUCK TRAFFIC ON PAVED ROADS[i] | VEHICULAR TRAFFIC | -- | -- | 0.11 lb/VMT | 0.022 lb/VMT | 0.0054 lb/VMT | WATER/SWEEP | 50 | 0.055 lb/VMT | 0.011 lb/VMT | 0.0027 lb/VMT | 70 VMT/day | 3.86 | 0.16 | 0.77 | 0.032 | 0.19 | 0.0079 |
| SORGHUM TRUCK TRAFFIC ON PAVED ROADS[i] | VEHICULAR TRAFFIC | -- | -- | 0.11 lb/VMT | 0.022 lb/VMT | 0.0054 lb/VMT | WATER/SWEEP | 50 | 0.055 lb/VMT | 0.011 lb/VMT | 0.0027 lb/VMT | 70 VMT/day | 3.86 | 0.16 | 0.77 | 0.032 | 0.19 | 0.0079 |
| WOOD TRUCK TRAFFIC ON PAVED ROADS[i] | VEHICULAR TRAFFIC | -- | -- | 0.11 lb/VMT | 0.022 lb/VMT | 0.0054 lb/VMT | WATER/SWEEP | 50 | 0.055 lb/VMT | 0.011 lb/VMT | 0.0027 lb/VMT | 4 VMT/day | 0.22 | 0.0093 | 0.045 | 0.0019 | 0.0109 | 0.00046 |
| BAGASSE HANDLING | | | | | | | | | | | | | | | | | | |
| BAGASSE FROM DRYING SYSTEM-TO-TRANSFER CONVEYOR | CONTINUOUS DROP | 50 | 10.51 | 0.000069 | 0.000032 | 0.0000049 | ENCLOSURE | 0 | 0.000069 | 0.000032 | 0.0000049 | 0 ton/day [d] | 0.00 | 0.0000 | 0.000 | 0.0000 | 0.000 | 0.00000 |
| TRANSFER CONVEYOR-TO-HOPPER | CONTINUOUS DROP | 50 | 10.51 | 0.000069 | 0.000032 | 0.0000049 | ENCLOSURE | 0 | 0.000069 | 0.000032 | 0.0000049 | 0 ton/day [d] | 0.00 | 0.0000 | 0.000 | 0.0000 | 0.000 | 0.00000 |
| HOPPER-TO-BAGASSE DISTRIBUTION CONVEYOR | CONTINUOUS DROP | 50 | 10.51 | 0.000069 | 0.000032 | 0.0000049 | ENCLOSURE | 0 | 0.000069 | 0.000032 | 0.0000049 | 0 ton/day [d] | 0.00 | 0.0000 | 0.000 | 0.0000 | 0.000 | 0.00000 |
| BAGASSE DISTRIBUTION CONVEYOR-TO-METER BINS | CONTINUOUS DROP | 50 | 10.51 | 0.000069 | 0.000032 | 0.0000049 | ENCLOSURE | 0 | 0.000069 | 0.000032 | 0.0000049 | 0 ton/day [d] | 0.00 | 0.0000 | 0.000 | 0.0000 | 0.000 | 0.00000 |
| BAG. DIS. CONV. OVERFLOW-TO-SURPLUS BAGASSE CONVEYOR | CONTINUOUS DROP | 50 | 10.51 | 0.000069 | 0.000032 | 0.0000049 | ENCLOSURE | 0 | 0.000069 | 0.000032 | 0.0000049 | 0 ton/day [e] | 0.000 | 0.00000 | 0.0000 | 0.00000 | 0.0000 | 0.000000 |
| SURPLUS BAGASSE CONVEYOR-TO-BAGASSE STORAGE PILE | CONTINUOUS DROP | 50 | 10.51 | 0.000069 | 0.000032 | 0.0000049 | ENCLOSURE | 0 | 0.000069 | 0.000032 | 0.0000049 | 0 ton/day [e] | 0.000 | 0.00000 | 0.0000 | 0.00000 | 0.0000 | 0.000000 |
| FRONT END LOADER (RECLAIM)-TO-RECLAIM CONVEYOR | BATCH DROP | 50 | 10.51 | 0.000069 | 0.000032 | 0.0000049 | NONE | 0 | 0.000069 | 0.000032 | 0.0000049 | 0 ton/day [e] | 0.000 | 0.00000 | 0.0000 | 0.00000 | 0.0000 | 0.000000 |
| RECLAIM CONVEYOR-TO-RETURN CONVEYOR | CONTINUOUS DROP | 50 | 10.51 | 0.000069 | 0.000032 | 0.0000049 | ENCLOSURE | 0 | 0.000069 | 0.000032 | 0.0000049 | 0 ton/day [e] | 0.000 | 0.00000 | 0.0000 | 0.00000 | 0.0000 | 0.000000 |
| RETURN CONVEYOR-TO-BAGASSE TRANSFER CONVEYOR | CONTINUOUS DROP | 50 | 10.51 | 0.000069 | 0.000032 | 0.0000049 | ENCLOSURE | 0 | 0.000069 | 0.000032 | 0.0000049 | 0 ton/day [e] | 0.000 | 0.00000 | 0.0000 | 0.00000 | 0.0000 | 0.000000 |
| BAGASSE TRANSFER CONVEYOR-TO-HOPPER | CONTINUOUS DROP | 50 | 10.51 | 0.000069 | 0.000032 | 0.0000049 | ENCLOSURE | 0 | 0.000069 | 0.000032 | 0.0000049 | 0 ton/day [e] | 0.000 | 0.00000 | 0.0000 | 0.00000 | 0.0000 | 0.000000 |
| HOPPER-TO-BAGASSE DISTRIBUTION CONVEYOR | CONTINUOUS DROP | 50 | 10.51 | 0.000069 | 0.000032 | 0.0000049 | ENCLOSURE | 0 | 0.000069 | 0.000032 | 0.0000049 | 0 ton/day [e] | 0.000 | 0.00000 | 0.0000 | 0.00000 | 0.0000 | 0.000000 |
| BAGASSE STORAGE PILE[f] | WIND EROSION | -- | -- | -- | -- | -- | WATERING | 50 | -- | -- | -- | -- | 0.37 | 0.042 | 0.19 | 0.021 | 0.19 | 0.021 |
| FRONT END LOADER BAGASSE STORAGE PILE MAINTENANCE[g] | VEHICULAR TRAFFIC | -- | -- | 0.40 lb/VMT | 0.047 lb/VMT | 0.0047 lb/VMT | PARTIAL ENCLOSURE/WATERING | 75 | 0.10 lb/VMT | 0.012 lb/VMT | 0.0012 lb/VMT | 30 VMT/day | 3.02 | 0.13 | 0.36 | 0.015 | 0.036 | 0.0015 |
| BULLDOZER BAGASSE STORAGE PILE MAINTENANCE[h] | VEHICULAR TRAFFIC | -- | -- | 0.031 lb/hr | 0.0018 lb/hr | 0.00067 lb/hr | PARTIAL ENCLOSURE/WATERING | 75 | 0.008 lb/hr | 0.00046 lb/hr | 0.00017 lb/hr | 6 hr/day | 0.046 | 0.0019 | 0.0028 | 0.00012 | 0.0010 | 0.000042 |
| WOOD HANDLING | | | | | | | | | | | | | | | | | | |
| TRUCK DUMP-TO-WOOD STORAGE PILE | BATCH DROP | 40 | 10.51 | 0.000094 | 0.000044 | 0.0000067 | NONE | 0 | 0.000094 | 0.000044 | 0.0000067 | 1,295 ton/day [d] | 0.12 | 0.0051 | 0.057 | 0.0024 | 0.009 | 0.00036 |
| UNLOADING CONVEYOR-TO-HOGGER | CONTINUOUS DROP | 40 | 10.51 | 0.000094 | 0.000044 | 0.0000067 | ENCLOSURE | 0 | 0.000094 | 0.000044 | 0.0000067 | 1,295 ton/day [d] | 0.12 | 0.0051 | 0.057 | 0.0024 | 0.009 | 0.00036 |
| HOGGER | CRUSHING | -- | -- | 0.020 | 0.0095 | 0.0014 | ENCLOSED | 95 | 0.0010 | 0.00047 | 0.000072 | 1,295 ton/day [d] | 1.29 | 0.054 | 0.61 | 0.026 | 0.093 | 0.0039 |
| HOGGER-TO-STORAGE CONVEYOR | BATCH DROP | 40 | 10.51 | 0.000094 | 0.000044 | 0.0000067 | ENCLOSURE | 0 | 0.000094 | 0.000044 | 0.0000067 | 1,295 ton/day [d] | 0.12 | 0.005 | 0.057 | 0.0024 | 0.0087 | 0.00036 |
| SCREEN-TO-STORAGE CONVEYOR | CONTINUOUS DROP | 40 | 10.51 | 0.000094 | 0.000044 | 0.0000067 | ENCLOSURE | 0 | 0.000094 | 0.000044 | 0.0000067 | 1,295 ton/day [d] | 0.12 | 0.005 | 0.057 | 0.0024 | 0.0087 | 0.00036 |
| STORAGE CONVEYOR-TO-WOOD STORAGE PILE | CONTINUOUS DROP | 40 | 10.51 | 0.000094 | 0.000044 | 0.0000067 | ENCLOSURE | 0 | 0.000094 | 0.000044 | 0.0000067 | 1,295 ton/day [e] | 0.12 | 0.005 | 0.057 | 0.0024 | 0.0087 | 0.00036 |
| FRONT END LOADER (RECLAIM)-TO-RECLAIM CONVEYOR | BATCH DROP | 40 | 10.51 | 0.000094 | 0.000044 | 0.0000067 | NONE | 0 | 0.000094 | 0.000044 | 0.0000067 | 1,295 ton/day [d] | 0.12 | 0.005 | 0.057 | 0.0024 | 0.0087 | 0.00036 |
| RECLAIM CONVEYOR-TO-RETURN CONVEYOR | CONTINUOUS DROP | 40 | 10.51 | 0.000094 | 0.000044 | 0.0000067 | ENCLOSURE | 0 | 0.000094 | 0.000044 | 0.0000067 | 1,295 ton/day [d] | 0.12 | 0.005 | 0.057 | 0.0024 | 0.0087 | 0.00036 |
| RETURN CONVEYOR-TO-HOPPER | CONTINUOUS DROP | 40 | 10.51 | 0.000094 | 0.000044 | 0.0000067 | ENCLOSURE | 0 | 0.000094 | 0.000044 | 0.0000067 | 1,295 ton/day [d] | 0.12 | 0.005 | 0.057 | 0.0024 | 0.0087 | 0.00036 |
| HOPPER-TO-HORIZONTAL DISCHARGE CONVEYOR | CONTINUOUS DROP | 40 | 10.51 | 0.000094 | 0.000044 | 0.0000067 | ENCLOSURE | 0 | 0.000094 | 0.000044 | 0.0000067 | 1,295 ton/day [d] | 0.12 | 0.005 | 0.057 | 0.0024 | 0.0087 | 0.00036 |
| WOOD STORAGE PILE[f] | WIND EROSION | -- | -- | -- | -- | -- | WATERING | 50 | -- | -- | -- | -- | 4.86 | 0.54 | 2.43 | 0.27 | 2.43 | 0.27 |
| FRONTEND LOADER WOOD STORAGE PILE MAINTENANCE[g] | VEHICULAR TRAFFIC | -- | -- | 5.24 lb/VMT | 1.28 lb/VMT | 0.13 lb/VMT | PARTIAL ENCLOSURE/WATERING | 75 | 1.31 lb/VMT | 0.32 lb/VMT | 0.032 lb/VMT | 30 VMT/day | 39.29 | 1.64 | 9.61 | 0.40 | 0.96 | 0.040 |
| BULLDOZER WOOD STORAGE PILE MAINTENANCE[h] | VEHICULAR TRAFFIC | -- | -- | 3.32 lb/hr | 0.61 lb/hr | 0.073 lb/hr | PARTIAL ENCLOSURE/WATERING | 75 | 0.83 lb/hr | 0.15 lb/hr | 0.018 lb/hr | 6 hr/day | 4.98 | 0.21 | 0.92 | 0.038 | 0.11 | 0.0046 |
| ASH HANDLING | | | | | | | | | | | | | | | | | | |
| ASH DROP TO DRAG CONVEYOR 1 | CONTINUOUS DROP | 10 | 10.51 | 0.000654 | 0.000309 | 0.0000468 | ENCLOSURE | 0 | 0.000654 | 0.000309 | 0.0000468 | 61.9 ton/day [j] | 0.040 | 0.0017 | 0.019 | 0.00080 | 0.0029 | 0.00012 |
| DRAG CONVEYOR 1 TO DRAG CONVEYOR 2 | CONTINUOUS DROP | 10 | 10.51 | 0.000654 | 0.000309 | 0.0000468 | ENCLOSURE | 0 | 0.000654 | 0.000309 | 0.0000468 | 61.9 ton/day [j] | 0.040 | 0.0017 | 0.019 | 0.00080 | 0.0029 | 0.00012 |
| DRAG CONVEYOR 2 TO DRAG CONVEYOR 3 | CONTINUOUS DROP | 10 | 10.51 | 0.000654 | 0.000309 | 0.0000468 | ENCLOSURE | 0 | 0.000654 | 0.000309 | 0.0000468 | 61.9 ton/day [j] | 0.040 | 0.0017 | 0.019 | 0.00080 | 0.0029 | 0.00012 |
| DRAG CONVEYOR 3 TO ASH SILO | CONTINUOUS DROP | 10 | 10.51 | 0.000654 | 0.000309 | 0.0000468 | ENCLOSURE | 0 | 0.000654 | 0.000309 | 0.0000468 | 61.9 ton/day [j] | 0.040 | 0.0017 | 0.019 | 0.00080 | 0.0029 | 0.00012 |
| ASH SILO TO TRUCK | CONTINUOUS DROP | 10 | 10.51 | 0.000654 | 0.000309 | 0.0000468 | ENCLOSURE | 0 | 0.000654 | 0.000309 | 0.0000468 | 61.9 ton/day [j] | 0.040 | 0.0017 | 0.019 | 0.00080 | 0.0029 | 0.00012 |
| ASH TRUCK TRAFFIC ON PAVED ROADS[j] | VEHICULAR TRAFFIC | -- | -- | 0.11 lb/VMT | 0.022 lb/VMT | 0.0054 lb/VMT | WATER/SWEEP | 50 | 0.055 lb/VMT | 0.011 lb/VMT | 0.0027 lb/VMT | 2.01 VMT/day | 0.11 | 0.005 | 0.022 | 0.00093 | 0.0055 | 0.00023 |
| PRODUCT LOAD OUT | | | | | | | | | | | | | | | | | | |
| ETHANOL TRUCK TRAFFIC ON PAVED ROADS[i] | VEHICULAR TRAFFIC | -- | -- | 0.13 lb/VMT | 0.027 lb/VMT | 0.0065 lb/VMT | WATER/SWEEP | 50 | 0.066 lb/VMT | 0.013 lb/VMT | 0.0033 lb/VMT | 11 VMT/day | 0.30 | 0.012 | 0.060 | 0.0025 | 0.015 | 0.00061 |
| DENATURANT/GASOLINE DELIVERIES | | | | | | | | | | | | | | | | | | |
| DENATURANT/GASOLINE TRUCK TRAFFIC ON PAVED ROADS[i] | VEHICULAR TRAFFIC | -- | -- | 0.13 lb/VMT | 0.027 lb/VMT | 0.0065 lb/VMT | WATER/SWEEP | 50 | 0.066 lb/VMT | 0.013 lb/VMT | 0.0033 lb/VMT | 1 VMT/day | 0.027 | 0.0011 | 0.0055 | 0.00023 | 0.0013 | 0.000056 |
| LIME DELIVERIES | | | | | | | | | | | | | | | | | | |
| LIME TRUCK TRAFFIC ON PAVED ROADS[i] | VEHICULAR TRAFFIC | -- | -- | 0.11 lb/VMT | 0.022 lb/VMT | 0.0054 lb/VMT | WATER/SWEEP | 50 | 0.055 lb/VMT | 0.011 lb/VMT | 0.0027 lb/VMT | 1 VMT/day | 0.047 | 0.0020 | 0.0094 | 0.00039 | 0.0023 | 0.00010 |
| TOTAL | | | | | | | | | | | | | 59.73 | 2.85 | 15.64 | 0.83 | 4.13 | 0.35 |

[a] Bagasse will be dried to 50% moisture after it is sent through the drying system. Wood moisture content based on sample testing conducted March 2008, New Hope Power Company, LLC.
[b] Based on the 90th percentile of 24-hour averages of hourly windspeed data from Fort Myers International Airport for 2001-2005.
[c] Batch Drop and Continuous Drop Emission Factors are computed from AP-42 (USEPA, 2006) Section 13.2.4: E= k x 0.0032 x (U/5)^1.3 / (M/2)^1.4 lb/ton, where k = 0.74 for PM, 0.35 for PM10, and .053 for $PM_{2.5}$.
[d] Refer to Table 2-2. Conveyors, screens, belts and hoppers operate for either wood or bagasse. Bagasse was used as a worst case scenario. The activity factor for bagasse is based on a maximum biomass usage of 458.5 MMBtu/hr and 7.8 MMBtu/ton for bagasse, and 24 hr/day.
[e] Assuming 10% of biomass is overfeed.
[f] Refer to Table C-1, Appendix C for calculation.
[g] Refer to C-2 in Appendix C.
[h] Refer to Table C-3 in Appendix C.
[i] Refer Table C-4 in Appendix C.
[j] Refer to Table C-4, Appendix C, for emissions calculation. Table 2-30 shows ash generation based on sugarcane bagasse at 1.5% ash, sorghum bagasse at 2.7% ash, wood at 9% ash.
[k] Emission factor reference: AP-42 (USEPA, 2004) Section 11.19.2. $PM_{2.5}$ assumed to be equal to $PM_{10}$.
[l] Based on firing sorghum bagasse for entire day with 2.7% ash.

# APPENDIX D

# VOL STORAGE TANKS EMISSION ESTIMATES

**Table D-1: Physical, Performance, and Emissions Data for Vertical Fixed Roof Tanks**

| **Tank Description** | **Corrosion Inhibitor Tank** |
| --- | --- |
| **Tank ID No.** | **6** |
| **<u>Model Input</u>** | |
| Subpart Kb Applies (Yes/No) | No |
| Tank Content[a] | Methanol, Xylene, and Ethylbenzene (mixture) |
| Tank Type | Vertical Fixed Roof |
| Tank Height (ft) | 8.0 |
| Tank Diameter (ft) | 7.0 |
| Tank Capacity (gallons) | 2,300 |
| Throughput (gal/yr) | 2,700 |
| Turnovers per Year | 1 |
| Maximum Liquid Height (ft) | 7.5 |
| Average Liquid Height (ft) | 7.5 |
| Heated Tank (Yes/No) | No |
| Underground Tank (Yes/No) | NA |
| External Shell Condition | Good |
| External Shell Shade | White |
| External Shell Color | White |
| Roof Color | White |
| Roof Shade | White |
| Roof Paint Condition | Good |
| Fixed Roof Type | Cone |
| Roof Height (ft) | 1 |
| Roof Slope (ft/ft) | 0.29 |
| Breather Vent Vacuum (psig) | -0.047 |
| Breather Vent Pressure (psig) | 0.5 |
| Nearest Major City | Fort Myers, FL |
| Daily Average Temperature (°F) | 74.35 |
| Annual Average Maximum Temperature (°F) | 84.35 |
| Annual Average Minimum Temperature (°F) | 64.75 |
| Average Wind Speed (mph) | 7.975 |
| Annual Average Insolation (Btu/ft$^2$-day) | 1,492 |
| Atmospheric Pressure (psia) | 14.76 |
| Modeled Liquid[a] | Methyl Alcohol Mixture (81% methyl alcohol, 4% mixed xylenes, 15% Ethyl benzene) |
| Liquid Molecular Weight | 36.94 |
| Vapor Molecular Weight | 32.4 |
| Average Bulk Temperature (°F) | 74.37 |
| Average Liquid Surface Temperature (°F) | 76.36 |
| Vapor Pressure at Liquid Surface Temperature (psia) | 2.22 |
| **<u>Model Output: VOC Emission Calculations</u>** | |
| <u>Annual</u> | |
| Working Loss (lb/yr) | 5.33 |
| Breathing Loss (lb/yr) | 6.66 |
| Total Losses (TPY) | 0.0060 |
| <u>Short-Term</u> | |
| Maximum Working Loss (lb/month) - May | 0.48 |
| Maximum Breathing Loss (lb/month) - May | 0.84 |
| Maximum Hourly Total Losses (lb/hr) | 0.0018 |
| **Total Losses for All Tanks (TPY)** | 0.0060 |
| **Maximum Hourly Overall Losses for All Tanks(lb/hr)** | 0.0018 |

[a] See the attached MSDS at the end of Appendix C for corrosion inhibitor speciation.

Table D-2: Physical, Performance, and Emissions Data for Internal Floating Roof Tanks

| Tank Description<br>Tank ID No. | Fuel Ethanol Storage Tank<br>1 | 200 Proof Ethanol Storage Tank<br>2 | Off-Spec Tank<br>4 | Denaturant/Gasoline Tank<br>5 |
|---|---|---|---|---|
| ***Model Input*** | | | | |
| Subpart Kb Applies (Yes/No) | Yes | Yes | Yes | Yes |
| Tank Content | Ethanol | Ethanol | Ethanol, off-spec | Gasoline[a] |
| Tank Type | Internal Floating Roof | Internal Floating Roof | Internal Floating Roof | Internal Floating Roof |
| Tank Diameter (ft) | 58.00 | 25.00 | 25.00 | 25.00 |
| Tank Capacity (gallons) | 1,000,000 | 100,000 | 100,000 | 100,000 |
| Throughput (gal/yr) | 36,000,000 | 36,000,000 | 3,600,000 | 1,620,000 |
| Turnovers per Year | 36 | 360 | 36 | 16 |
| Self-Supporting Roof (Yes/No) | No | No | No | No |
| Columns | 1 | 1 | 1 | 1 |
| Effective Column Diameter | Unknown | Unknown | Unknown | Unknown |
| Internal Shell Condition | Light Rust | Light Rust | Light Rust | Light Rust |
| External Shell Condition | Good | Good | Good | Good |
| External Shell Shade | White | White | White | White |
| External Shell Color | White | White | White | White |
| Roof Color | White | White | White | White |
| Roof Shade | White | White | White | White |
| Roof Paint Condition | Good | Good | Good | Good |
| Primary Seal | Vapor Mounted | Vapor Mounted | Vapor Mounted | Vapor Mounted |
| Secondary Seal | None | None | None | None |
| Deck Type | Welded | Welded | Welded | Welded |
| Deck Fittings | Typical | Typical | Typical | Typical |
| | | | | |
| Nearest Major City | Fort Myers, FL | Fort Myers, FL | Fort Myers, FL | Fort Myers, FL |
| Daily Average Temperature (°F) | 74.35 | 74.35 | 74.35 | 74.35 |
| Annual Average Maximum Temperature (°F) | 84.35 | 84.35 | 84.35 | 84.35 |
| Annual Average Minimum Temperature (°F) | 64.75 | 64.75 | 64.75 | 64.75 |
| Average Wind Speed (mph) | 7.975 | 7.975 | 7.975 | 7.975 |
| Annual Average Insolation (Btu/ft$^2$-day) | 1,492 | 1,492 | 1,492 | 1,492 |
| Atmospheric Pressure (psia) | 14.76 | 14.76 | 14.76 | 14.76 |
| | | | | |
| Modeled Liquid | Ethyl Alcohol | Ethyl Alcohol | Ethyl Alcohol | Gasoline (RVP of 12) |
| Liquid Molecular Weight | 46.07 | 46.07 | 46.07 | 92 |
| Vapor Molecular Weight | 46.07 | 46.07 | 46.07 | 64 |
| Average Bulk Temperature (°F) | NA | NA | NA | 74.74 |
| Average Liquid Surface Temperature (°F) | 76.36 | 76.36 | 76.36 | 76.75 |
| Vapor Pressure at Liquid Surface Temperature (psia) | 1.131 | 1.131 | 1.131 | 8.63 |
| | | | | |
| **Model Output: VOC Emission Calculations** | | | | |
| Annual | | | | |
| Rim Seal Loss (lb/yr) | 356.72 | 153.76 | 153.76 | 2294.6 |
| Withdrawal Loss (lb/yr) | 140.56 | 333.39 | 33.34 | 12.71 |
| Deck Fitting Loss (lb/yr) | 298.80 | 240.78 | 240.78 | 3593.28 |
| Deck Seam Loss (lb/yr) | 0 | 0 | 0 | 0 |
| **Total Losses (TPY)** | 0.40 | 0.36 | 0.21 | 2.95 |
| | | | | |
| Short-Term | | | | |
| Rim Seal Loss (lb/month) - July | 34.01 | 14.66 | 14.66 | 214.26 |
| Withdrawal Loss (lb/month - July) | 11.71 | 27.78 | 2.78 | 1.0592 |
| Deck Fitting Loss (lb/month) - July | 28.49 | 22.96 | 22.96 | 335.52 |
| Deck Seam Loss (lb/month) - July | 0 | 0 | 0 | 0 |
| **Maximum Hourly Total Losses (lb/hr)** | 0.10 | 0.088 | 0.054 | 0.74 |
| | | | | |
| | | | **Overall Losses (TPY)** | **3.93** |
| | | | **Maximum Hourly Overall Losses (lb/hr)** | **0.98** |

[a] Gasoline represents a worst case for emissions, however, during normal operation the blend tank may contain various ratios of denaturant/gasoline and ethanol.

**Table D-3: Hazardous Air Pollutant Emissions from Tanks**

| VOC Emissions | Denaturant/Gasoline Tank |
|---|---|
| Maximum Hourly (lb/hr) | 0.74 |
| Total Losses (TPY) | 2.95 |

| Speciated Constituents of Gasoline VOCs[a] | CAS Number | % of Total Vapor Released | VOC Speciated Emissions Gasoline Tank (lb/hr) | VOC Speciated Emissions Gasoline Tank (TPY) |
|---|---|---|---|---|
| **Benzene[b]** | **71-43-2** | **1.41** | **0.010** | **0.042** |
| Butane, n- | 106-97-8 | 28.53 | 0.21 | 0.84 |
| Butene, cis-2- | 590-18-1 | 0.83 | 0.0061 | 0.024 |
| Butene, trans-2- | 624-64-6 | 1.02 | 0.008 | 0.030 |
| Pentene, cis-2- | 627-20-3 | 0.67 | 0.0050 | 0.020 |
| Cyclohexane | 110-82-7 | 0.43 | 0.0032 | 0.013 |
| Cyclopentane | 287-92-3 | 0.61 | 0.0045 | 0.018 |
| Dimethylbutane, 2,2- | 75-83-2 | 1.04 | 0.008 | 0.031 |
| Dimethylpentane, 2,4- | 108-08-7 | 0.43 | 0.0032 | 0.013 |
| Ethane | 74-84-0 | 0.07 | 0.00052 | 0.0021 |
| **Ethylbenzene[b]** | **100-41-4** | **0.06** | **0.00044** | **0.0018** |
| Heptane, n- | 142-82-5 | 0.40 | 0.0030 | 0.012 |
| **Hexane, n-[b]** | **110-54-3** | **3.75** | 0.028 | 0.11 |
| Isobutane | 75-28-5 | 8.34 | 0.062 | 0.25 |
| Isopropyl Benzene | 98-82-8 | 0.01 | 0.00007 | 0.00030 |
| Methylcyclohexane | 108-87-2 | 0.12 | 0.0009 | 0.0035 |
| Methylcyclopentane | 96-37-7 | 1.41 | 0.010 | 0.042 |
| Methylheptane, 3- | 589-81-1 | 0.06 | 0.00044 | 0.0018 |
| Methylhexane, 3- | 589-34-4 | 0.42 | 0.0031 | 0.012 |
| Methylpentane, 3- | 96-14-0 | 1.99 | 0.015 | 0.059 |
| Octane, n- | 111-65-9 | 0.03 | 0.00022 | 0.0009 |
| Pentane, n- | 109-66-0 | 7.25 | 0.054 | 0.21 |
| Pentene, 1- | 109-67-1 | 0.86 | 0.0064 | 0.025 |
| Propane | 74-98-6 | 1.06 | 0.008 | 0.031 |
| **Toluene[b]** | **108-88-3** | **1.25** | **0.009** | **0.037** |
| Trans-2-Pentene | 646-04-8 | 1.37 | 0.010 | 0.040 |
| Trimethylbenzene, 1,2,4- | 95-63-6 | 0.05 | 0.00037 | 0.0015 |
| Trimethylbenzene, 1,3,5- | 108-67-8 | 0.02 | 0.00015 | 0.00059 |
| **Trimethylpentane, 2,2,4-[b]** | **540-84-1** | **0.42** | **0.0031** | **0.012** |
| Trimethylpentane, 2,3,4- | 565-75-3 | 0.07 | 0.00052 | 0.0021 |
| **Xylene, o-[b]** | **95-47-6** | **0.04** | **0.00030** | **0.0012** |
| Unidentified VOC | NA | 35.98 | 0.27 | 1.06 |
| | | **Total VOC** | 0.74 | 2.95 |
| | | **Total HAPs** | 0.024 | 0.09 |

[a] Speciation is based on EPA's SPECIATE 3.2 program for profile No. 2490 (Composition of 14 Emission Profiles from Gasoline Storage Tanks - 1993).

[b] Hazardous Air Pollutant (HAP).

## TANKS OUTPUT SUMMARY FOR HIGHLANDS ENVIROFUELS
## APRIL 2011

# TANKS 4.0.9d
# Emissions Report - Detail Format
# Tank Indentification and Physical Characteristics

| | |
|---|---|
| **Identification** | |
| User Identification: | HEF-Corr |
| City: | |
| State: | Florida |
| Company: | |
| Type of Tank: | Vertical Fixed Roof Tank |
| Description: | Highlands - Corrosion Inhibitor Tank |
| **Tank Dimensions** | |
| Shell Height (ft): | 8.00 |
| Diameter (ft): | 7.00 |
| Liquid Height (ft) : | 7.50 |
| Avg. Liquid Height (ft): | 7.50 |
| Volume (gallons): | 2,300.00 |
| Turnovers: | 1.35 |
| Net Throughput(gal/yr): | 3,105.00 |
| Is Tank Heated (y/n): | N |
| **Paint Characteristics** | |
| Shell Color/Shade: | White/White |
| Shell Condition | Good |
| Roof Color/Shade: | White/White |
| Roof Condition: | Good |
| **Roof Characteristics** | |
| Type: | Cone |
| Height (ft) | 1.00 |
| Slope (ft/ft) (Cone Roof) | 0.29 |
| **Breather Vent Settings** | |
| Vacuum Settings (psig): | -0.05 |
| Pressure Settings (psig) | 0.50 |

Meterological Data used in Emissions Calculations: Fort Myers, Florida (Avg Atmospheric Pressure = 14.76 psia)

# TANKS 4.0.9d
# Emissions Report - Detail Format
# Liquid Contents of Storage Tank

### HEF-Corr - Vertical Fixed Roof Tank
### , Florida

| | Daily Liquid Surf. Temperature (deg F) | Liquid Bulk | Vapor Pressure (psia) | Vapor Mol. | Liquid Mass | Vapor Mass | Mol. | Basis for Vapor Pressure |
|---|---|---|---|---|---|---|---|---|

| Mixture/Component | Month | Avg. | Min. | Max. | Temp (deg F) | Avg. | Min. | Max. | Weight. | Fract. | Fract. | Weight | Calculations |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Methyl alcohol | Jan | 71.05 | 66.05 | 76.05 | 74.37 | 1.9004 | 1.6330 | 2.2042 | 32.3943 | | | 36.94 | Option 2: A=7.897, B=1474.08, C=229.13 |
| Ethylbenzene | | | | | | 0.1579 | 0.1336 | 0.1858 | 106.1700 | 0.0400 | 0.0038 | 106.17 | Option 2: A=6.975, B=1424.255, C=213.21 |
| Methyl alcohol | | | | | | 2.0252 | 1.7404 | 2.3487 | 32.0400 | 0.8100 | 0.9843 | 32.04 | Option 2: A=7.897, B=1474.08, C=229.13 |
| Xylenes (mixed isomers) | | | | | | 0.1320 | 0.1115 | 0.1556 | 106.1700 | 0.1500 | 0.0119 | 106.17 | Option 2: A=7.009, B=1462.266, C=215.11 |
| Methyl alcohol | Feb | 71.85 | 66.53 | 77.16 | 74.37 | 1.9462 | 1.6573 | 2.2770 | 32.3953 | | | 36.94 | Option 2: A=7.897, B=1474.08, C=229.13 |
| Ethylbenzene | | | | | | 0.1621 | 0.1358 | 0.1926 | 106.1700 | 0.0400 | 0.0038 | 106.17 | Option 2: A=6.975, B=1424.255, C=213.21 |
| Methyl alcohol | | | | | | 2.0740 | 1.7663 | 2.4263 | 32.0400 | 0.8100 | 0.9843 | 32.04 | Option 2: A=7.897, B=1474.08, C=229.13 |
| Xylenes (mixed isomers) | | | | | | 0.1355 | 0.1133 | 0.1613 | 106.1700 | 0.1500 | 0.0119 | 106.17 | Option 2: A=7.009, B=1462.266, C=215.11 |
| Methyl alcohol | Mar | 74.21 | 68.52 | 79.90 | 74.37 | 2.0878 | 1.7605 | 2.4656 | 32.3980 | | | 36.94 | Option 2: A=7.897, B=1474.08, C=229.13 |
| Ethylbenzene | | | | | | 0.1751 | 0.1451 | 0.2102 | 106.1700 | 0.0400 | 0.0038 | 106.17 | Option 2: A=6.975, B=1424.255, C=213.21 |
| Methyl alcohol | | | | | | 2.2248 | 1.8762 | 2.6271 | 32.0400 | 0.8100 | 0.9842 | 32.04 | Option 2: A=7.897, B=1474.08, C=229.13 |
| Xylenes (mixed isomers) | | | | | | 0.1465 | 0.1212 | 0.1762 | 106.1700 | 0.1500 | 0.0120 | 106.17 | Option 2: A=7.009, B=1462.266, C=215.11 |
| Methyl alcohol | Apr | 76.37 | 70.10 | 82.64 | 74.37 | 2.2249 | 1.8471 | 2.6666 | 32.4005 | | | 36.94 | Option 2: A=7.897, B=1474.08, C=229.13 |
| Ethylbenzene | | | | | | 0.1878 | 0.1530 | 0.2291 | 106.1700 | 0.0400 | 0.0038 | 106.17 | Option 2: A=6.975, B=1424.255, C=213.21 |
| Methyl alcohol | | | | | | 2.3709 | 1.9684 | 2.8413 | 32.0400 | 0.8100 | 0.9841 | 32.04 | Option 2: A=7.897, B=1474.08, C=229.13 |
| Xylenes (mixed isomers) | | | | | | 0.1572 | 0.1278 | 0.1922 | 106.1700 | 0.1500 | 0.0121 | 106.17 | Option 2: A=7.009, B=1462.266, C=215.11 |
| Methyl alcohol | May | 78.78 | 72.66 | 84.90 | 74.37 | 2.3867 | 1.9939 | 2.8435 | 32.4032 | | | 36.94 | Option 2: A=7.897, B=1474.08, C=229.13 |
| Ethylbenzene | | | | | | 0.2028 | 0.1664 | 0.2458 | 106.1700 | 0.0400 | 0.0039 | 106.17 | Option 2: A=6.975, B=1424.255, C=213.21 |
| Methyl alcohol | | | | | | 2.5432 | 2.1248 | 3.0296 | 32.0400 | 0.8100 | 0.9839 | 32.04 | Option 2: A=7.897, B=1474.08, C=229.13 |
| Xylenes (mixed isomers) | | | | | | 0.1700 | 0.1392 | 0.2064 | 106.1700 | 0.1500 | 0.0122 | 106.17 | Option 2: A=7.009, B=1462.266, C=215.11 |
| Methyl alcohol | Jun | 80.07 | 74.78 | 85.37 | 74.37 | 2.4776 | 2.1232 | 2.8811 | 32.4047 | | | 36.94 | Option 2: A=7.897, B=1474.08, C=229.13 |
| Ethylbenzene | | | | | | 0.2113 | 0.1783 | 0.2494 | 106.1700 | 0.0400 | 0.0039 | 106.17 | Option 2: A=6.975, B=1424.255, C=213.21 |
| Methyl alcohol | | | | | | 2.6400 | 2.2625 | 3.0696 | 32.0400 | 0.8100 | 0.9839 | 32.04 | Option 2: A=7.897, B=1474.08, C=229.13 |
| Xylenes (mixed isomers) | | | | | | 0.1772 | 0.1493 | 0.2094 | 106.1700 | 0.1500 | 0.0122 | 106.17 | Option 2: A=7.009, B=1462.266, C=215.11 |
| Methyl alcohol | Jul | 80.43 | 75.36 | 85.50 | 74.37 | 2.5032 | 2.1597 | 2.8921 | 32.4051 | | | 36.94 | Option 2: A=7.897, B=1474.08, C=229.13 |
| Ethylbenzene | | | | | | 0.2137 | 0.1817 | 0.2504 | 106.1700 | 0.0400 | 0.0039 | 106.17 | Option 2: A=6.975, B=1424.255, C=213.21 |
| Methyl alcohol | | | | | | 2.6672 | 2.3013 | 3.0813 | 32.0400 | 0.8100 | 0.9839 | 32.04 | Option 2: A=7.897, B=1474.08, C=229.13 |
| Xylenes (mixed isomers) | | | | | | 0.1792 | 0.1521 | 0.2103 | 106.1700 | 0.1500 | 0.0122 | 106.17 | Option 2: A=7.009, B=1462.266, C=215.11 |
| Methyl alcohol | Aug | 80.38 | 75.43 | 85.34 | 74.37 | 2.5000 | 2.1643 | 2.8789 | 32.4050 | | | 36.94 | Option 2: A=7.897, B=1474.08, C=229.13 |
| Ethylbenzene | | | | | | 0.2134 | 0.1821 | 0.2492 | 106.1700 | 0.0400 | 0.0039 | 106.17 | Option 2: A=6.975, B=1424.255, C=213.21 |
| Methyl alcohol | | | | | | 2.6638 | 2.3063 | 3.0673 | 32.0400 | 0.8100 | 0.9839 | 32.04 | Option 2: A=7.897, B=1474.08, C=229.13 |
| Xylenes (mixed isomers) | | | | | | 0.1789 | 0.1525 | 0.2093 | 106.1700 | 0.1500 | 0.0122 | 106.17 | Option 2: A=7.009, B=1462.266, C=215.11 |
| Methyl alcohol | Sep | 79.73 | 75.15 | 84.31 | 74.37 | 2.4531 | 2.1462 | 2.7965 | 32.4043 | | | 36.94 | Option 2: A=7.897, B=1474.08, C=229.13 |
| Ethylbenzene | | | | | | 0.2090 | 0.1805 | 0.2414 | 106.1700 | 0.0400 | 0.0039 | 106.17 | Option 2: A=6.975, B=1424.255, C=213.21 |
| Methyl alcohol | | | | | | 2.6139 | 2.2870 | 2.9796 | 32.0400 | 0.8100 | 0.9839 | 32.04 | Option 2: A=7.897, B=1474.08, C=229.13 |
| Xylenes (mixed isomers) | | | | | | 0.1752 | 0.1511 | 0.2026 | 106.1700 | 0.1500 | 0.0122 | 106.17 | Option 2: A=7.009, B=1462.266, C=215.11 |
| Methyl alcohol | Oct | 77.42 | 72.72 | 82.12 | 74.37 | 2.2942 | 1.9977 | 2.6274 | 32.4017 | | | 36.94 | Option 2: A=7.897, B=1474.08, C=229.13 |
| Ethylbenzene | | | | | | 0.1942 | 0.1668 | 0.2254 | 106.1700 | 0.0400 | 0.0039 | 106.17 | Option 2: A=6.975, B=1424.255, C=213.21 |
| Methyl alcohol | | | | | | 2.4447 | 2.1288 | 2.7995 | 32.0400 | 0.8100 | 0.9840 | 32.04 | Option 2: A=7.897, B=1474.08, C=229.13 |
| Xylenes (mixed isomers) | | | | | | 0.1627 | 0.1395 | 0.1891 | 106.1700 | 0.1500 | 0.0121 | 106.17 | Option 2: A=7.009, B=1462.266, C=215.11 |
| Methyl alcohol | Nov | 74.28 | 69.40 | 79.16 | 74.37 | 2.0924 | 1.8084 | 2.4135 | 32.3981 | | | 36.94 | Option 2: A=7.897, B=1474.08, C=229.13 |
| Ethylbenzene | | | | | | 0.1755 | 0.1495 | 0.2053 | 106.1700 | 0.0400 | 0.0038 | 106.17 | Option 2: A=6.975, B=1424.255, C=213.21 |
| Methyl alcohol | | | | | | 2.2297 | 1.9272 | 2.5717 | 32.0400 | 0.8100 | 0.9842 | 32.04 | Option 2: A=7.897, B=1474.08, C=229.13 |
| Xylenes (mixed isomers) | | | | | | 0.1469 | 0.1249 | 0.1721 | 106.1700 | 0.1500 | 0.0120 | 106.17 | Option 2: A=7.009, B=1462.266, C=215.11 |
| Methyl alcohol | Dec | 71.74 | 66.87 | 76.62 | 74.37 | 1.9401 | 1.6744 | 2.2410 | 32.3951 | | | 36.94 | Option 2: A=7.897, B=1474.08, C=229.13 |
| Ethylbenzene | | | | | | 0.1615 | 0.1373 | 0.1893 | 106.1700 | 0.0400 | 0.0038 | 106.17 | Option 2: A=6.975, B=1424.255, C=213.21 |
| Methyl alcohol | | | | | | 2.0675 | 1.7844 | 2.3880 | 32.0400 | 0.8100 | 0.9843 | 32.04 | Option 2: A=7.897, B=1474.08, C=229.13 |
| Xylenes (mixed isomers) | | | | | | 0.1350 | 0.1146 | 0.1585 | 106.1700 | 0.1500 | 0.0119 | 106.17 | Option 2: A=7.009, B=1462.266, C=215.11 |

# TANKS 4.0.9d
## Emissions Report - Detail Format
## Detail Calculations (AP-42)

## HEF-Corr - Vertical Fixed Roof Tank
## , Florida

| Month: | January | February | March | April | May | June | July | August | September | October | November | December |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Standing Losses (lb): | 0.3922 | 0.4174 | 0.5925 | 0.7521 | 0.8418 | 0.6780 | 0.6603 | 0.6304 | 0.5052 | 0.4846 | 0.4288 | 0.3858 |
| Vapor Space Volume (cu ft): | 32.0704 | 32.0704 | 32.0704 | 32.0704 | 32.0704 | 32.0704 | 32.0704 | 32.0704 | 32.0704 | 32.0704 | 32.0704 | 32.0704 |
| Vapor Density (lb/cu ft): | 0.0108 | 0.0111 | 0.0118 | 0.0125 | 0.0134 | 0.0139 | 0.0140 | 0.0140 | 0.0137 | 0.0129 | 0.0118 | 0.0110 |
| Vapor Space Expansion Factor: | 0.0396 | 0.0457 | 0.0551 | 0.0685 | 0.0699 | 0.0564 | 0.0527 | 0.0504 | 0.0424 | 0.0416 | 0.0412 | 0.0382 |
| Vented Vapor Saturation Factor: | 0.9226 | 0.9208 | 0.9156 | 0.9105 | 0.9046 | 0.9014 | 0.9004 | 0.9006 | 0.9022 | 0.9080 | 0.9154 | 0.9211 |
| Tank Vapor Space Volume: | | | | | | | | | | | | |
| Vapor Space Volume (cu ft): | 32.0704 | 32.0704 | 32.0704 | 32.0704 | 32.0704 | 32.0704 | 32.0704 | 32.0704 | 32.0704 | 32.0704 | 32.0704 | 32.0704 |
| Tank Diameter (ft): | 7.0000 | 7.0000 | 7.0000 | 7.0000 | 7.0000 | 7.0000 | 7.0000 | 7.0000 | 7.0000 | 7.0000 | 7.0000 | 7.0000 |
| Vapor Space Outage (ft): | 0.8333 | 0.8333 | 0.8333 | 0.8333 | 0.8333 | 0.8333 | 0.8333 | 0.8333 | 0.8333 | 0.8333 | 0.8333 | 0.8333 |
| Tank Shell Height (ft): | 8.0000 | 8.0000 | 8.0000 | 8.0000 | 8.0000 | 8.0000 | 8.0000 | 8.0000 | 8.0000 | 8.0000 | 8.0000 | 8.0000 |
| Average Liquid Height (ft): | 7.5000 | 7.5000 | 7.5000 | 7.5000 | 7.5000 | 7.5000 | 7.5000 | 7.5000 | 7.5000 | 7.5000 | 7.5000 | 7.5000 |
| Roof Outage (ft): | 0.3333 | 0.3333 | 0.3333 | 0.3333 | 0.3333 | 0.3333 | 0.3333 | 0.3333 | 0.3333 | 0.3333 | 0.3333 | 0.3333 |
| Roof Outage (Cone Roof) | | | | | | | | | | | | |
| Roof Outage (ft): | 0.3333 | 0.3333 | 0.3333 | 0.3333 | 0.3333 | 0.3333 | 0.3333 | 0.3333 | 0.3333 | 0.3333 | 0.3333 | 0.3333 |
| Roof Height (ft): | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 |
| Roof Slope (ft/ft): | 0.2900 | 0.2900 | 0.2900 | 0.2900 | 0.2900 | 0.2900 | 0.2900 | 0.2900 | 0.2900 | 0.2900 | 0.2900 | 0.2900 |
| Shell Radius (ft): | 3.5000 | 3.5000 | 3.5000 | 3.5000 | 3.5000 | 3.5000 | 3.5000 | 3.5000 | 3.5000 | 3.5000 | 3.5000 | 3.5000 |
| Vapor Density | | | | | | | | | | | | |
| Vapor Density (lb/cu ft): | 0.0108 | 0.0111 | 0.0118 | 0.0125 | 0.0134 | 0.0139 | 0.0140 | 0.0140 | 0.0137 | 0.0129 | 0.0118 | 0.0110 |
| Vapor Molecular Weight (lb/lb-mole): | 32.3943 | 32.3953 | 32.3980 | 32.4005 | 32.4032 | 32.4047 | 32.4051 | 32.4050 | 32.4043 | 32.4017 | 32.3981 | 32.3951 |
| Vapor Pressure at Daily Average Liquid Surface Temperature (psia): | 1.9004 | 1.9462 | 2.0878 | 2.2249 | 2.3867 | 2.4776 | 2.5032 | 2.5000 | 2.4531 | 2.2942 | 2.0924 | 1.9401 |
| Daily Avg. Liquid Surface Temp. (deg. R): | 530.7213 | 531.5177 | 533.8803 | 536.0413 | 538.4502 | 539.7434 | 540.0998 | 540.0548 | 539.3986 | 537.0905 | 533.9536 | 531.4126 |
| Daily Average Ambient Temp. (deg. F): | 63.7500 | 64.8000 | 69.1500 | 73.1000 | 78.3000 | 81.7000 | 82.8000 | 83.0000 | 82.0000 | 77.2000 | 70.8000 | 65.5500 |
| Ideal Gas Constant R (psia cuft / (lb-mol-deg R)): | 10.731 | 10.731 | 10.731 | 10.731 | 10.731 | 10.731 | 10.731 | 10.731 | 10.731 | 10.731 | 10.731 | 10.731 |
| Liquid Bulk Temperature (deg. R): | 534.0358 | 534.0358 | 534.0358 | 534.0358 | 534.0358 | 534.0358 | 534.0358 | 534.0358 | 534.0358 | 534.0358 | 534.0358 | 534.0358 |
| Tank Paint Solar Absorptance (Shell): | 0.1700 | 0.1700 | 0.1700 | 0.1700 | 0.1700 | 0.1700 | 0.1700 | 0.1700 | 0.1700 | 0.1700 | 0.1700 | 0.1700 |
| Tank Paint Solar Absorptance (Roof): | 0.1700 | 0.1700 | 0.1700 | 0.1700 | 0.1700 | 0.1700 | 0.1700 | 0.1700 | 0.1700 | 0.1700 | 0.1700 | 0.1700 |
| Daily Total Solar Insulation Factor (Btu/sqft day): | 1,010.0000 | 1,259.0000 | 1,593.0000 | 1,908.0000 | 1,998.0000 | 1,847.0000 | 1,752.0000 | 1,653.0000 | 1,492.0000 | 1,346.0000 | 1,107.0000 | 935.0000 |
| Vapor Space Expansion Factor | | | | | | | | | | | | |
| Vapor Space Expansion Factor: | 0.0396 | 0.0457 | 0.0551 | 0.0685 | 0.0699 | 0.0564 | 0.0527 | 0.0504 | 0.0424 | 0.0416 | 0.0412 | 0.0382 |
| Daily Vapor Temperature Range (deg. R): | 19.9996 | 21.2568 | 22.7747 | 25.0661 | 24.4865 | 21.1757 | 20.2915 | 19.8203 | 18.3339 | 18.7910 | 19.5253 | 19.4986 |
| Daily Vapor Pressure Range (psia): | 0.5711 | 0.6197 | 0.7050 | 0.8196 | 0.8496 | 0.7579 | 0.7324 | 0.7146 | 0.6503 | 0.6297 | 0.6051 | 0.5667 |
| Breather Vent Press. Setting Range(psia): | 0.5470 | 0.5470 | 0.5470 | 0.5470 | 0.5470 | 0.5470 | 0.5470 | 0.5470 | 0.5470 | 0.5470 | 0.5470 | 0.5470 |
| Vapor Pressure at Daily Average Liquid Surface Temperature (psia): | 1.9004 | 1.9462 | 2.0878 | 2.2249 | 2.3867 | 2.4776 | 2.5032 | 2.5000 | 2.4531 | 2.2942 | 2.0924 | 1.9401 |
| Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia): | 1.6330 | 1.6573 | 1.7605 | 1.8471 | 1.9939 | 2.1232 | 2.1597 | 2.1643 | 2.1462 | 1.9977 | 1.8084 | 1.6744 |
| Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia): | 2.2042 | 2.2770 | 2.4656 | 2.6666 | 2.8435 | 2.8811 | 2.8921 | 2.8789 | 2.7965 | 2.6274 | 2.4135 | 2.2410 |
| Daily Avg. Liquid Surface Temp. (deg R): | 530.7213 | 531.5177 | 533.8803 | 536.0413 | 538.4502 | 539.7434 | 540.0998 | 540.0548 | 539.3986 | 537.0905 | 533.9536 | 531.4126 |
| Daily Min. Liquid Surface Temp. (deg R): | 525.7214 | 526.2035 | 528.1866 | 529.7748 | 532.3286 | 534.4495 | 535.0269 | 535.0998 | 534.8151 | 532.3928 | 529.0722 | 526.5379 |
| Daily Max. Liquid Surface Temp. (deg R): | 535.7212 | 536.8319 | 539.5739 | 542.3078 | 544.5718 | 545.0373 | 545.1727 | 545.0099 | 543.9821 | 541.7883 | 538.8349 | 536.2872 |
| Daily Ambient Temp. Range (deg. R): | 21.1000 | 21.2000 | 21.1000 | 22.2000 | 20.8000 | 17.2000 | 16.6000 | 16.6000 | 15.6000 | 17.2000 | 19.8000 | 20.9000 |
| Vented Vapor Saturation Factor | | | | | | | | | | | | |
| Vented Vapor Saturation Factor: | 0.9226 | 0.9208 | 0.9156 | 0.9105 | 0.9046 | 0.9014 | 0.9004 | 0.9006 | 0.9022 | 0.9080 | 0.9154 | 0.9211 |
| Vapor Pressure at Daily Average Liquid: Surface Temperature (psia): | 1.9004 | 1.9462 | 2.0878 | 2.2249 | 2.3867 | 2.4776 | 2.5032 | 2.5000 | 2.4531 | 2.2942 | 2.0924 | 1.9401 |
| Vapor Space Outage (ft): | 0.8333 | 0.8333 | 0.8333 | 0.8333 | 0.8333 | 0.8333 | 0.8333 | 0.8333 | 0.8333 | 0.8333 | 0.8333 | 0.8333 |
| Working Losses (lb): | 0.3793 | 0.3884 | 0.4167 | 0.4441 | 0.4765 | 0.4946 | 0.4997 | 0.4991 | 0.4897 | 0.4580 | 0.4176 | 0.3872 |
| Vapor Molecular Weight (lb/lb-mole): | 32.3943 | 32.3953 | 32.3980 | 32.4005 | 32.4032 | 32.4047 | 32.4051 | 32.4050 | 32.4043 | 32.4017 | 32.3981 | 32.3951 |
| Vapor Pressure at Daily Average Liquid Surface Temperature (psia): | 1.9004 | 1.9462 | 2.0878 | 2.2249 | 2.3867 | 2.4776 | 2.5032 | 2.5000 | 2.4531 | 2.2942 | 2.0924 | 1.9401 |
| Net Throughput (gal/mo.): | 258.7500 | 258.7500 | 258.7500 | 258.7500 | 258.7500 | 258.7500 | 258.7500 | 258.7500 | 258.7500 | 258.7500 | 258.7500 | 258.7500 |
| Annual Turnovers: | 1.3500 | 1.3500 | 1.3500 | 1.3500 | 1.3500 | 1.3500 | 1.3500 | 1.3500 | 1.3500 | 1.3500 | 1.3500 | 1.3500 |
| Turnover Factor: | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Maximum Liquid Volume (gal): | 2,300.0000 | 2,300.0000 | 2,300.0000 | 2,300.0000 | 2,300.0000 | 2,300.0000 | 2,300.0000 | 2,300.0000 | 2,300.0000 | 2,300.0000 | 2,300.0000 | 2,300.0000 |
| Maximum Liquid Height (ft): | 7.5000 | 7.5000 | 7.5000 | 7.5000 | 7.5000 | 7.5000 | 7.5000 | 7.5000 | 7.5000 | 7.5000 | 7.5000 | 7.5000 |
| Tank Diameter (ft): | 7.0000 | 7.0000 | 7.0000 | 7.0000 | 7.0000 | 7.0000 | 7.0000 | 7.0000 | 7.0000 | 7.0000 | 7.0000 | 7.0000 |
| Working Loss Product Factor: | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 |
| Total Losses (lb): | 0.7715 | 0.8058 | 1.0092 | 1.1962 | 1.3183 | 1.1726 | 1.1600 | 1.1295 | 0.9950 | 0.9426 | 0.8465 | 0.7730 |

# TANKS 4.0.9d
# Emissions Report - Detail Format
# Individual Tank Emission Totals

## Emissions Report for: January, February, March, April, May, June, July, August, September, October, November, December

### HEF-Corr - Vertical Fixed Roof Tank
### , Florida

| | Losses(lbs) | | |
|---|---|---|---|
| Components | Working Loss | Breathing Loss | Total Emissions |
| Methyl alcohol | 5.35 | 6.77 | 12.12 |
| Ethylbenzene | 0.02 | 0.03 | 0.05 |
| Methyl alcohol | 5.27 | 6.66 | 11.93 |
| Xylenes (mixed isomers) | 0.06 | 0.08 | 0.15 |

# TANKS 4.0.9d
## Emissions Report - Summary Format
## Tank Indentification and Physical Characteristics

| | |
|---|---|
| **Identification** | |
| User Identification: | HEF-Corr |
| City: | |
| State: | Florida |
| Company: | |
| Type of Tank: | Vertical Fixed Roof Tank |
| Description: | Highlands - Corrosion Inhibitor Tank |
| **Tank Dimensions** | |
| Shell Height (ft): | 8.00 |
| Diameter (ft): | 7.00 |
| Liquid Height (ft) : | 7.50 |
| Avg. Liquid Height (ft): | 7.50 |
| Volume (gallons): | 2,300.00 |
| Turnovers: | 1.35 |
| Net Throughput(gal/yr): | 3,105.00 |
| Is Tank Heated (y/n): | N |
| **Paint Characteristics** | |
| Shell Color/Shade: | White/White |
| Shell Condition | Good |
| Roof Color/Shade: | White/White |
| Roof Condition: | Good |
| **Roof Characteristics** | |
| Type: | Cone |
| Height (ft) | 1.00 |
| Slope (ft/ft) (Cone Roof) | 0.29 |
| **Breather Vent Settings** | |
| Vacuum Settings (psig): | -0.05 |
| Pressure Settings (psig) | 0.50 |

Meterological Data used in Emissions Calculations: Fort Myers, Florida (Avg Atmospheric Pressure = 14.76 psia)

# TANKS 4.0.9d
## Emissions Report - Summary Format
## Liquid Contents of Storage Tank

**HEF-Corr - Vertical Fixed Roof Tank**
**, Florida**

| Mixture/Component | Month | Daily Liquid Surf. Temperature (deg F) Avg. | Min. | Max. | Liquid Bulk Temp (deg F) | Vapor Pressure (psia) Avg. | Min. | Max. | Vapor Mol. Weight. | Liquid Mass Fract. | Vapor Mass Fract. | Mol. Weight | Basis for Vapor Pressure Calculations |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Methyl alcohol | All | 76.36 | 71.13 | 81.59 | 74.37 | 2.2242 | 1.9049 | 2.5880 | 32.4005 | | | 36.94 | Option 2: A=7.897, B=1474.08, C=229.13 |
| Ethylbenzene | | | | | | 0.1877 | 0.1583 | 0.2217 | 106.1700 | 0.0400 | 0.0038 | 106.17 | Option 2: A=6.975, B=1424.255, C=213.21 |
| Methyl alcohol | | | | | | 2.3701 | 2.0300 | 2.7575 | 32.0400 | 0.8100 | 0.9841 | 32.04 | Option 2: A=7.897, B=1474.08, C=229.13 |
| Xylenes (mixed isomers) | | | | | | 0.1572 | 0.1323 | 0.1860 | 106.1700 | 0.1500 | 0.0121 | 106.17 | Option 2: A=7.009, B=1462.266, C=215.11 |

# TANKS 4.0.9d
## Emissions Report - Summary Format
## Individual Tank Emission Totals

## Emissions Report for: Annual

**HEF-Corr - Vertical Fixed Roof Tank**
**, Florida**

| | Losses(lbs) | | |
|---|---|---|---|
| Components | Working Loss | Breathing Loss | Total Emissions |
| Methyl alcohol | 5.33 | 6.66 | 11.99 |
| Methyl alcohol | 5.24 | 6.55 | 11.80 |
| Ethylbenzene | 0.02 | 0.03 | 0.05 |
| Xylenes (mixed isomers) | 0.06 | 0.08 | 0.14 |

# TANKS 4.0.9d
## Emissions Report - Detail Format
## Tank Indentification and Physical Characteristics

| | |
|---|---|
| **Identification** | |
| User Identification: | HEF - Fuel Ethanol |
| City: | |
| State: | |
| Company: | |
| Type of Tank: | Internal Floating Roof Tank |
| Description: | |
| **Tank Dimensions** | |
| Diameter (ft): | 58.00 |
| Volume (gallons): | 1,000,000.00 |
| Turnovers: | 36.00 |
| Self Supp. Roof? (y/n): | N |
| No. of Columns: | 1.00 |
| Eff. Col. Diam. (ft): | 1.00 |
| **Paint Characteristics** | |
| Internal Shell Condition: | Light Rust |
| Shell Color/Shade: | White/White |
| Shell Condition | Good |
| Roof Color/Shade: | White/White |
| Roof Condition: | Good |
| **Rim-Seal System** | |
| Primary Seal: | Vapor-mounted |
| Secondary Seal | None |
| **Deck Characteristics** | |
| Deck Fitting Category: | Typical |
| Deck Type: | Welded |

| Deck Fitting/Status | Quantity |
|---|---|
| Access Hatch (24-in. Diam.)/Unbolted Cover, Ungasketed | 1 |
| Automatic Gauge Float Well/Unbolted Cover, Ungasketed | 1 |
| Column Well (24-in. Diam.)/Built-Up Col.-Sliding Cover, Ungask. | 1 |
| Ladder Well (36-in. Diam.)/Sliding Cover, Ungasketed | 1 |
| Roof Leg or Hanger Well/Adjustable | 17 |
| Sample Pipe or Well (24-in. Diam.)/Slit Fabric Seal 10% Open | 1 |
| Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask. | 1 |

Meterological Data used in Emissions Calculations: Fort Myers, Florida (Avg Atmospheric Pressure = 14.76 psia)

# TANKS 4.0.9d
# Emissions Report - Detail Format
# Liquid Contents of Storage Tank

## HEF - Fuel Ethanol - Internal Floating Roof Tank

| Mixture/Component | Month | Daily Liquid Surf. Temperature (deg F) Avg. | Min. | Max. | Liquid Bulk Temp (deg F) | Vapor Pressure (psia) Avg. | Min. | Max. | Vapor Mol. Weight. | Liquid Mass Fract. | Vapor Mass Fract. | Mol. Weight | Basis for Vapor Pressure Calculations |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Ethyl alcohol | Jan | 71.05 | 66.05 | 76.05 | 74.37 | 0.9525 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | Feb | 71.85 | 66.53 | 77.16 | 74.37 | 0.9776 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | Mar | 74.21 | 68.52 | 79.90 | 74.37 | 1.0555 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | Apr | 76.37 | 70.10 | 82.64 | 74.37 | 1.1314 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | May | 78.78 | 72.66 | 84.90 | 74.37 | 1.2215 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | Jun | 80.07 | 74.78 | 85.37 | 74.37 | 1.2724 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | Jul | 80.43 | 75.36 | 85.50 | 74.37 | 1.2867 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | Aug | 80.38 | 75.43 | 85.34 | 74.37 | 1.2849 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | Sep | 79.73 | 75.15 | 84.31 | 74.37 | 1.2586 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | Oct | 77.42 | 72.72 | 82.12 | 74.37 | 1.1699 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | Nov | 74.28 | 69.40 | 79.16 | 74.37 | 1.0580 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | Dec | 71.74 | 66.87 | 76.62 | 74.37 | 0.9743 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |

# TANKS 4.0.9d
# Emissions Report - Detail Format
# Detail Calculations (AP-42)


## HEF - Fuel Ethanol - Internal Floating Roof Tank


| Month: | January | February | March | April | May | June | July | August | September | October | November | December |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Rim Seal Losses (lb): | 24.8774 | 25.5557 | 27.6680 | 29.7379 | 32.2110 | 33.6151 | 34.0118 | 33.9615 | 33.2354 | 30.7930 | 27.7360 | 25.4652 |
| Seal Factor A (lb-mole/ft-yr): | 6.7000 | 6.7000 | 6.7000 | 6.7000 | 6.7000 | 6.7000 | 6.7000 | 6.7000 | 6.7000 | 6.7000 | 6.7000 | 6.7000 |
| Seal Factor B (lb-mole/ft-yr (mph)^n): | 0.2000 | 0.2000 | 0.2000 | 0.2000 | 0.2000 | 0.2000 | 0.2000 | 0.2000 | 0.2000 | 0.2000 | 0.2000 | 0.2000 |
| Value of Vapor Pressure Function: | 0.0167 | 0.0171 | 0.0185 | 0.0199 | 0.0216 | 0.0225 | 0.0228 | 0.0228 | 0.0223 | 0.0206 | 0.0186 | 0.0171 |
| Vapor Pressure at Daily Average Liquid Surface Temperature (psia): | 0.9525 | 0.9776 | 1.0555 | 1.1314 | 1.2215 | 1.2724 | 1.2867 | 1.2849 | 1.2586 | 1.1699 | 1.0580 | 0.9743 |
| Tank Diameter (ft): | 58.0000 | 58.0000 | 58.0000 | 58.0000 | 58.0000 | 58.0000 | 58.0000 | 58.0000 | 58.0000 | 58.0000 | 58.0000 | 58.0000 |
| Vapor Molecular Weight (lb/lb-mole): | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 |
| Product Factor: | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 |
| Withdrawal Losses (lb): | 11.7131 | 11.7131 | 11.7131 | 11.7131 | 11.7131 | 11.7131 | 11.7131 | 11.7131 | 11.7131 | 11.7131 | 11.7131 | 11.7131 |
| Number of Columns: | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 |
| Effective Column Diameter (ft): | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 |
| Net Throughput (gal/mo.): | 3,000,000.0000 | 3,000,000.0000 | 3,000,000.0000 | 3,000,000.0000 | 3,000,000.0000 | 3,000,000.0000 | 3,000,000.0000 | 3,000,000.0000 | 3,000,000.0000 | 3,000,000.0000 | 3,000,000.0000 | 3,000,000.0000 |
| Shell Clingage Factor (bbl/1000 sqft): | 0.0015 | 0.0015 | 0.0015 | 0.0015 | 0.0015 | 0.0015 | 0.0015 | 0.0015 | 0.0015 | 0.0015 | 0.0015 | 0.0015 |
| Average Organic Liquid Density (lb/gal): | 6.6100 | 6.6100 | 6.6100 | 6.6100 | 6.6100 | 6.6100 | 6.6100 | 6.6100 | 6.6100 | 6.6100 | 6.6100 | 6.6100 |
| Tank Diameter (ft): | 58.0000 | 58.0000 | 58.0000 | 58.0000 | 58.0000 | 58.0000 | 58.0000 | 58.0000 | 58.0000 | 58.0000 | 58.0000 | 58.0000 |
| Deck Fitting Losses (lb): | 20.8379 | 21.4060 | 23.1753 | 24.9091 | 26.9807 | 28.1567 | 28.4890 | 28.4469 | 27.8387 | 25.7929 | 23.2323 | 21.3302 |
| Value of Vapor Pressure Function: | 0.0167 | 0.0171 | 0.0185 | 0.0199 | 0.0216 | 0.0225 | 0.0228 | 0.0228 | 0.0223 | 0.0206 | 0.0186 | 0.0171 |
| Vapor Molecular Weight (lb/lb-mole): | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 |
| Product Factor: | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Tot. Roof Fitting Loss Fact.(lb-mole/yr): | 325.5000 | 325.5000 | 325.5000 | 325.5000 | 325.5000 | 325.5000 | 325.5000 | 325.5000 | 325.5000 | 325.5000 | 325.5000 | 325.5000 |
| Deck Seam Losses (lb): | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| Deck Seam Length (ft): | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| Deck Seam Loss per Unit Length Factor (lb-mole/ft-yr): | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| Deck Seam Length Factor(ft/sqft): | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| Tank Diameter (ft): | 58.0000 | 58.0000 | 58.0000 | 58.0000 | 58.0000 | 58.0000 | 58.0000 | 58.0000 | 58.0000 | 58.0000 | 58.0000 | 58.0000 |
| Vapor Molecular Weight (lb/lb-mole): | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 |
| Product Factor: | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 |
| Total Losses (lb): | 57.4284 | 58.6749 | 62.5564 | 66.3601 | 70.9048 | 73.4849 | 74.2139 | 74.1215 | 72.7872 | 68.2989 | 62.6813 | 58.5086 |

| Roof Fitting/Status | Quantity | Roof Fitting Loss Factors KFa(lb-mole/yr) | KFb(lb-mole/(yr mph^n)) | m | Losses(lb) |
|---|---|---|---|---|---|
| Access Hatch (24-in. Diam.)/Unbolted Cover, Ungasketed | 1 | 36.00 | 5.90 | 1.20 | 33.2710 |
| Automatic Gauge Float Well/Unbolted Cover, Ungasketed | 1 | 14.00 | 5.40 | 1.10 | 12.9387 |
| Column Well (24-in. Diam.)/Built-Up Col.-Sliding Cover, Ungask. | 1 | 47.00 | 0.00 | 0.00 | 43.4372 |
| Ladder Well (36-in. Diam.)/Sliding Cover, Ungasketed | 1 | 76.00 | 0.00 | 0.00 | 70.2389 |
| Roof Leg or Hanger Well/Adjustable | 17 | 7.90 | 0.00 | 0.00 | 124.1194 |
| Sample Pipe or Well (24-in. Diam.)/Slit Fabric Seal 10% Open | 1 | 12.00 | 0.00 | 0.00 | 11.0903 |
| Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask. | 1 | 6.20 | 1.20 | 0.94 | 5.7300 |

# TANKS 4.0.9d
# Emissions Report - Detail Format
# Individual Tank Emission Totals

## Emissions Report for: January, February, March, April, May, June, July, August, September, October, November, December

### HEF - Fuel Ethanol - Internal Floating Roof Tank

| | Losses(lbs) | | | | |
|---|---|---|---|---|---|
| Components | Rim Seal Loss | Withdrawl Loss | Deck Fitting Loss | Deck Seam Loss | Total Emissions |
| Ethyl alcohol | 358.87 | 140.56 | 300.60 | 0.00 | 800.02 |

# TANKS 4.0.9d
## Emissions Report - Summary Format
## Tank Indentification and Physical Characteristics

| | |
|---|---|
| **Identification** | |
| User Identification: | HEF - Fuel Ethanol |
| City: | |
| State: | |
| Company: | |
| Type of Tank: | Internal Floating Roof Tank |
| Description: | |
| **Tank Dimensions** | |
| Diameter (ft): | 58.00 |
| Volume (gallons): | 1,000,000.00 |
| Turnovers: | 36.00 |
| Self Supp. Roof? (y/n): | N |
| No. of Columns: | 1.00 |
| Eff. Col. Diam. (ft): | 1.00 |
| **Paint Characteristics** | |
| Internal Shell Condition: | Light Rust |
| Shell Color/Shade: | White/White |
| Shell Condition | Good |
| Roof Color/Shade: | White/White |
| Roof Condition: | Good |
| **Rim-Seal System** | |
| Primary Seal: | Vapor-mounted |
| Secondary Seal | None |
| **Deck Characteristics** | |
| Deck Fitting Category: | Typical |
| Deck Type: | Welded |

| Deck Fitting/Status | Quantity |
|---|---|
| Access Hatch (24-in. Diam.)/Unbolted Cover, Ungasketed | 1 |
| Automatic Gauge Float Well/Unbolted Cover, Ungasketed | 1 |
| Column Well (24-in. Diam.)/Built-Up Col.-Sliding Cover, Ungask. | 1 |
| Ladder Well (36-in. Diam.)/Sliding Cover, Ungasketed | 1 |
| Roof Leg or Hanger Well/Adjustable | 17 |
| Sample Pipe or Well (24-in. Diam.)/Slit Fabric Seal 10% Open | 1 |
| Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask. | 1 |

Meterological Data used in Emissions Calculations: Fort Myers, Florida (Avg Atmospheric Pressure = 14.76 psia)

# TANKS 4.0.9d
# Emissions Report - Summary Format
# Liquid Contents of Storage Tank

## HEF - Fuel Ethanol - Internal Floating Roof Tank

| Mixture/Component | Month | Daily Liquid Surf. Temperature (deg F) Avg. | Min. | Max. | Liquid Bulk Temp (deg F) | Vapor Pressure (psia) Avg. | Min. | Max. | Vapor Mol. Weight. | Liquid Mass Fract. | Vapor Mass Fract. | Mol. Weight | Basis for Vapor Pressure Calculations |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Ethyl alcohol | All | 76.36 | 71.13 | 81.59 | 74.37 | 1.1310 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |

# TANKS 4.0.9d
# Emissions Report - Summary Format
# Individual Tank Emission Totals

## Emissions Report for: Annual

## HEF - Fuel Ethanol - Internal Floating Roof Tank

| | Losses(lbs) | | | | |
|---|---|---|---|---|---|
| Components | Rim Seal Loss | Withdrawl Loss | Deck Fitting Loss | Deck Seam Loss | Total Emissions |
| Ethyl alcohol | 356.72 | 140.56 | 298.80 | 0.00 | 796.08 |

# TANKS 4.0.9d
## Emissions Report - Detail Format
## Tank Indentification and Physical Characteristics

| | |
|---|---|
| **Identification** | |
| User Identification: | HEF - 200 Proof Ethanol |
| City: | |
| State: | |
| Company: | |
| Type of Tank: | Internal Floating Roof Tank |
| Description: | |
| **Tank Dimensions** | |
| Diameter (ft): | 25.00 |
| Volume (gallons): | 100,000.00 |
| Turnovers: | 360.00 |
| Self Supp. Roof? (y/n): | N |
| No. of Columns: | 1.00 |
| Eff. Col. Diam. (ft): | 1.00 |
| **Paint Characteristics** | |
| Internal Shell Condition: | Light Rust |
| Shell Color/Shade: | White/White |
| Shell Condition | Good |
| Roof Color/Shade: | White/White |
| Roof Condition: | Good |
| **Rim-Seal System** | |
| Primary Seal: | Vapor-mounted |
| Secondary Seal | None |
| **Deck Characteristics** | |
| Deck Fitting Category: | Typical |
| Deck Type: | Welded |

| Deck Fitting/Status | Quantity |
|---|---|
| Access Hatch (24-in. Diam.)/Unbolted Cover, Ungasketed | 1 |
| Automatic Gauge Float Well/Unbolted Cover, Ungasketed | 1 |
| Column Well (24-in. Diam.)/Built-Up Col.-Sliding Cover, Ungask. | 1 |
| Ladder Well (36-in. Diam.)/Sliding Cover, Ungasketed | 1 |
| Roof Leg or Hanger Well/Adjustable | 9 |
| Sample Pipe or Well (24-in. Diam.)/Slit Fabric Seal 10% Open | 1 |
| Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask. | 1 |

Meterological Data used in Emissions Calculations: Fort Myers, Florida (Avg Atmospheric Pressure = 14.76 psia)

# TANKS 4.0.9d
# Emissions Report - Detail Format
# Liquid Contents of Storage Tank

## HEF - 200 Proof Ethanol - Internal Floating Roof Tank

| Mixture/Component | Month | Daily Liquid Surf. Temperature (deg F) Avg. | Min. | Max. | Liquid Bulk Temp (deg F) | Vapor Pressure (psia) Avg. | Min. | Max. | Vapor Mol. Weight. | Liquid Mass Fract. | Vapor Mass Fract. | Mol. Weight | Basis for Vapor Pressure Calculations |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Ethyl alcohol | Jan | 71.05 | 66.05 | 76.05 | 74.37 | 0.9525 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | Feb | 71.85 | 66.53 | 77.16 | 74.37 | 0.9776 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | Mar | 74.21 | 68.52 | 79.90 | 74.37 | 1.0555 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | Apr | 76.37 | 70.10 | 82.64 | 74.37 | 1.1314 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | May | 78.78 | 72.66 | 84.90 | 74.37 | 1.2215 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | Jun | 80.07 | 74.78 | 85.37 | 74.37 | 1.2724 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | Jul | 80.43 | 75.36 | 85.50 | 74.37 | 1.2867 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | Aug | 80.38 | 75.43 | 85.34 | 74.37 | 1.2849 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | Sep | 79.73 | 75.15 | 84.31 | 74.37 | 1.2586 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | Oct | 77.42 | 72.72 | 82.12 | 74.37 | 1.1699 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | Nov | 74.28 | 69.40 | 79.16 | 74.37 | 1.0580 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | Dec | 71.74 | 66.87 | 76.62 | 74.37 | 0.9743 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |

# TANKS 4.0.9d
# Emissions Report - Detail Format
# Detail Calculations (AP-42)

## HEF - 200 Proof Ethanol - Internal Floating Roof Tank

| Month: | January | February | March | April | May | June | July | August | September | October | November | December |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Rim Seal Losses (lb): | 10.7230 | 11.0154 | 11.9258 | 12.8181 | 13.8841 | 14.4893 | 14.6602 | 14.6386 | 14.3256 | 13.2728 | 11.9552 | 10.9764 |
| Seal Factor A (lb-mole/ft-yr): | 6.7000 | 6.7000 | 6.7000 | 6.7000 | 6.7000 | 6.7000 | 6.7000 | 6.7000 | 6.7000 | 6.7000 | 6.7000 | 6.7000 |
| Seal Factor B (lb-mole/ft-yr (mph)^n): | 0.2000 | 0.2000 | 0.2000 | 0.2000 | 0.2000 | 0.2000 | 0.2000 | 0.2000 | 0.2000 | 0.2000 | 0.2000 | 0.2000 |
| Value of Vapor Pressure Function: | 0.0167 | 0.0171 | 0.0185 | 0.0199 | 0.0216 | 0.0225 | 0.0228 | 0.0228 | 0.0223 | 0.0206 | 0.0186 | 0.0171 |
| Vapor Pressure at Daily Average Liquid Surface Temperature (psia): | 0.9525 | 0.9776 | 1.0555 | 1.1314 | 1.2215 | 1.2724 | 1.2867 | 1.2849 | 1.2586 | 1.1699 | 1.0580 | 0.9743 |
| Tank Diameter (ft): | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 |
| Vapor Molecular Weight (lb/lb-mole): | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 |
| Product Factor: | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 |
| Withdrawal Losses (lb): | 27.7824 | 27.7824 | 27.7824 | 27.7824 | 27.7824 | 27.7824 | 27.7824 | 27.7824 | 27.7824 | 27.7824 | 27.7824 | 27.7824 |
| Number of Columns: | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 |
| Effective Column Diameter (ft): | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 |
| Net Throughput (gal/mo.): | 3,000,000.0000 | 3,000,000.0000 | 3,000,000.0000 | 3,000,000.0000 | 3,000,000.0000 | 3,000,000.0000 | 3,000,000.0000 | 3,000,000.0000 | 3,000,000.0000 | 3,000,000.0000 | 3,000,000.0000 | 3,000,000.0000 |
| Shell Clingage Factor (bbl/1000 sqft): | 0.0015 | 0.0015 | 0.0015 | 0.0015 | 0.0015 | 0.0015 | 0.0015 | 0.0015 | 0.0015 | 0.0015 | 0.0015 | 0.0015 |
| Average Organic Liquid Density (lb/gal): | 6.6100 | 6.6100 | 6.6100 | 6.6100 | 6.6100 | 6.6100 | 6.6100 | 6.6100 | 6.6100 | 6.6100 | 6.6100 | 6.6100 |
| Tank Diameter (ft): | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 |
| Deck Fitting Losses (lb): | 16.7919 | 17.2498 | 18.6755 | 20.0727 | 21.7420 | 22.6897 | 22.9575 | 22.9236 | 22.4335 | 20.7848 | 18.7214 | 17.1887 |
| Value of Vapor Pressure Function: | 0.0167 | 0.0171 | 0.0185 | 0.0199 | 0.0216 | 0.0225 | 0.0228 | 0.0228 | 0.0223 | 0.0206 | 0.0186 | 0.0171 |
| Vapor Molecular Weight (lb/lb-mole): | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 |
| Product Factor: | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Tot. Roof Fitting Loss Fact.(lb-mole/yr): | 262.3000 | 262.3000 | 262.3000 | 262.3000 | 262.3000 | 262.3000 | 262.3000 | 262.3000 | 262.3000 | 262.3000 | 262.3000 | 262.3000 |
| Deck Seam Losses (lb): | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| Deck Seam Length (ft): | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| Deck Seam Loss per Unit Length Factor (lb-mole/ft-yr): | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| Deck Seam Length Factor(ft/sqft): | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| Tank Diameter (ft): | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 |
| Vapor Molecular Weight (lb/lb-mole): | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 |
| Product Factor: | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 |
| Total Losses (lb): | 55.2973 | 56.0476 | 58.3838 | 60.6731 | 63.4085 | 64.9614 | 65.4002 | 65.3446 | 64.5414 | 61.8401 | 58.4590 | 55.9475 |

| Roof Fitting/Status | Quantity | Roof Fitting Loss Factors KFa(lb-mole/yr) | KFb(lb-mole/(yr mph^n)) | m | Losses(lb) |
|---|---|---|---|---|---|
| Access Hatch (24-in. Diam.)/Unbolted Cover, Ungasketed | 1 | 36.00 | 5.90 | 1.20 | 33.2710 |
| Automatic Gauge Float Well/Unbolted Cover, Ungasketed | 1 | 14.00 | 5.40 | 1.10 | 12.9387 |
| Column Well (24-in. Diam.)/Built-Up Col.-Sliding Cover, Ungask. | 1 | 47.00 | 0.00 | 0.00 | 43.4372 |
| Ladder Well (36-in. Diam.)/Sliding Cover, Ungasketed | 1 | 76.00 | 0.00 | 0.00 | 70.2389 |
| Roof Leg or Hanger Well/Adjustable | 9 | 7.90 | 0.00 | 0.00 | 65.7103 |
| Sample Pipe or Well (24-in. Diam.)/Slit Fabric Seal 10% Open | 1 | 12.00 | 0.00 | 0.00 | 11.0903 |
| Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask. | 1 | 6.20 | 1.20 | 0.94 | 5.7300 |

# TANKS 4.0.9d
# Emissions Report - Detail Format
# Individual Tank Emission Totals

## Emissions Report for: January, February, March, April, May, June, July, August, September, October, November, December

### HEF - 200 Proof Ethanol - Internal Floating Roof Tank

| | Losses(lbs) | | | | |
|---|---|---|---|---|---|
| Components | Rim Seal Loss | Withdrawl Loss | Deck Fitting Loss | Deck Seam Loss | Total Emissions |
| Ethyl alcohol | 154.68 | 333.39 | 242.23 | 0.00 | 730.30 |

# TANKS 4.0.9d
## Emissions Report - Summary Format
## Tank Indentification and Physical Characteristics

**Identification**

| | |
|---|---|
| User Identification: | HEF - 200 Proof Ethanol |
| City: | |
| State: | |
| Company: | |
| Type of Tank: | Internal Floating Roof Tank |
| Description: | |

**Tank Dimensions**

| | |
|---|---|
| Diameter (ft): | 25.00 |
| Volume (gallons): | 100,000.00 |
| Turnovers: | 360.00 |
| Self Supp. Roof? (y/n): | N |
| No. of Columns: | 1.00 |
| Eff. Col. Diam. (ft): | 1.00 |

**Paint Characteristics**

| | |
|---|---|
| Internal Shell Condition: | Light Rust |
| Shell Color/Shade: | White/White |
| Shell Condition | Good |
| Roof Color/Shade: | White/White |
| Roof Condition: | Good |

**Rim-Seal System**

| | |
|---|---|
| Primary Seal: | Vapor-mounted |
| Secondary Seal | None |

**Deck Characteristics**

| | |
|---|---|
| Deck Fitting Category: | Typical |
| Deck Type: | Welded |

| Deck Fitting/Status | Quantity |
|---|---|
| Access Hatch (24-in. Diam.)/Unbolted Cover, Ungasketed | 1 |
| Automatic Gauge Float Well/Unbolted Cover, Ungasketed | 1 |
| Column Well (24-in. Diam.)/Built-Up Col.-Sliding Cover, Ungask. | 1 |
| Ladder Well (36-in. Diam.)/Sliding Cover, Ungasketed | 1 |
| Roof Leg or Hanger Well/Adjustable | 9 |
| Sample Pipe or Well (24-in. Diam.)/Slit Fabric Seal 10% Open | 1 |
| Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask. | 1 |

Meterological Data used in Emissions Calculations: Fort Myers, Florida (Avg Atmospheric Pressure = 14.76 psia)

# TANKS 4.0.9d
# Emissions Report - Summary Format
# Liquid Contents of Storage Tank

### HEF - 200 Proof Ethanol - Internal Floating Roof Tank

| Mixture/Component | Month | Daily Liquid Surf. Temperature (deg F) Avg. | Min. | Max. | Liquid Bulk Temp (deg F) | Vapor Pressure (psia) Avg. | Min. | Max. | Vapor Mol. Weight. | Liquid Mass Fract. | Vapor Mass Fract. | Mol. Weight | Basis for Vapor Pressure Calculations |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Ethyl alcohol | All | 76.36 | 71.13 | 81.59 | 74.37 | 1.1310 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |

# TANKS 4.0.9d
# Emissions Report - Summary Format
# Individual Tank Emission Totals

## Emissions Report for: Annual

### HEF - 200 Proof Ethanol - Internal Floating Roof Tank

| | Losses(lbs) | | | | |
|---|---|---|---|---|---|
| Components | Rim Seal Loss | Withdrawl Loss | Deck Fitting Loss | Deck Seam Loss | Total Emissions |
| Ethyl alcohol | 153.76 | 333.39 | 240.78 | 0.00 | 727.93 |

# TANKS 4.0.9d
## Emissions Report - Detail Format
## Tank Indentification and Physical Characteristics

| | |
|---|---|
| **Identification** | |
| User Identification: | HEF - Off-spec tank |
| City: | |
| State: | |
| Company: | |
| Type of Tank: | Internal Floating Roof Tank |
| Description: | |
| **Tank Dimensions** | |
| Diameter (ft): | 25.00 |
| Volume (gallons): | 100,000.00 |
| Turnovers: | 36.00 |
| Self Supp. Roof? (y/n): | N |
| No. of Columns: | 1.00 |
| Eff. Col. Diam. (ft): | 1.00 |
| **Paint Characteristics** | |
| Internal Shell Condition: | Light Rust |
| Shell Color/Shade: | White/White |
| Shell Condition | Good |
| Roof Color/Shade: | White/White |
| Roof Condition: | Good |
| **Rim-Seal System** | |
| Primary Seal: | Vapor-mounted |
| Secondary Seal | None |
| **Deck Characteristics** | |
| Deck Fitting Category: | Typical |
| Deck Type: | Welded |

| Deck Fitting/Status | Quantity |
|---|---|
| Access Hatch (24-in. Diam.)/Unbolted Cover, Ungasketed | 1 |
| Automatic Gauge Float Well/Unbolted Cover, Ungasketed | 1 |
| Column Well (24-in. Diam.)/Built-Up Col.-Sliding Cover, Ungask. | 1 |
| Ladder Well (36-in. Diam.)/Sliding Cover, Ungasketed | 1 |
| Roof Leg or Hanger Well/Adjustable | 9 |
| Sample Pipe or Well (24-in. Diam.)/Slit Fabric Seal 10% Open | 1 |
| Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask. | 1 |

Meterological Data used in Emissions Calculations: Fort Myers, Florida (Avg Atmospheric Pressure = 14.76 psia)

# TANKS 4.0.9d
# Emissions Report - Detail Format
# Liquid Contents of Storage Tank

## HEF - Off-spec tank - Internal Floating Roof Tank

| Mixture/Component | Month | Daily Liquid Surf. Temperature (deg F) Avg. | Min. | Max. | Liquid Bulk Temp (deg F) | Vapor Pressure (psia) Avg. | Min. | Max. | Vapor Mol. Weight. | Liquid Mass Fract. | Vapor Mass Fract. | Mol. Weight | Basis for Vapor Pressure Calculations |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Ethyl alcohol | Jan | 71.05 | 66.05 | 76.05 | 74.37 | 0.9525 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | Feb | 71.85 | 66.53 | 77.16 | 74.37 | 0.9776 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | Mar | 74.21 | 68.52 | 79.90 | 74.37 | 1.0555 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | Apr | 76.37 | 70.10 | 82.64 | 74.37 | 1.1314 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | May | 78.78 | 72.66 | 84.90 | 74.37 | 1.2215 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | Jun | 80.07 | 74.78 | 85.37 | 74.37 | 1.2724 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | Jul | 80.43 | 75.36 | 85.50 | 74.37 | 1.2867 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | Aug | 80.38 | 75.43 | 85.34 | 74.37 | 1.2849 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | Sep | 79.73 | 75.15 | 84.31 | 74.37 | 1.2586 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | Oct | 77.42 | 72.72 | 82.12 | 74.37 | 1.1699 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | Nov | 74.28 | 69.40 | 79.16 | 74.37 | 1.0580 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |
| Ethyl alcohol | Dec | 71.74 | 66.87 | 76.62 | 74.37 | 0.9743 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |

# TANKS 4.0.9d
# Emissions Report - Detail Format
# Detail Calculations (AP-42)

## HEF - Off-spec tank - Internal Floating Roof Tank

| Month: | January | February | March | April | May | June | July | August | September | October | November | December |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Rim Seal Losses (lb): | 10.7230 | 11.0154 | 11.9258 | 12.8181 | 13.8841 | 14.4893 | 14.6602 | 14.6386 | 14.3256 | 13.2728 | 11.9552 | 10.9764 |
| Seal Factor A (lb-mole/ft-yr): | 6.7000 | 6.7000 | 6.7000 | 6.7000 | 6.7000 | 6.7000 | 6.7000 | 6.7000 | 6.7000 | 6.7000 | 6.7000 | 6.7000 |
| Seal Factor B (lb-mole/ft-yr (mph)^n): | 0.2000 | 0.2000 | 0.2000 | 0.2000 | 0.2000 | 0.2000 | 0.2000 | 0.2000 | 0.2000 | 0.2000 | 0.2000 | 0.2000 |
| Value of Vapor Pressure Function: | 0.0167 | 0.0171 | 0.0185 | 0.0199 | 0.0216 | 0.0225 | 0.0228 | 0.0228 | 0.0223 | 0.0206 | 0.0186 | 0.0171 |
| Vapor Pressure at Daily Average Liquid Surface Temperature (psia): | 0.9525 | 0.9776 | 1.0555 | 1.1314 | 1.2215 | 1.2724 | 1.2867 | 1.2849 | 1.2586 | 1.1699 | 1.0580 | 0.9743 |
| Tank Diameter (ft): | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 |
| Vapor Molecular Weight (lb/lb-mole): | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 |
| Product Factor: | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 |
| Withdrawal Losses (lb): | 2.7782 | 2.7782 | 2.7782 | 2.7782 | 2.7782 | 2.7782 | 2.7782 | 2.7782 | 2.7782 | 2.7782 | 2.7782 | 2.7782 |
| Number of Columns: | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 |
| Effective Column Diameter (ft): | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 |
| Net Throughput (gal/mo.): | 300,000.0000 | 300,000.0000 | 300,000.0000 | 300,000.0000 | 300,000.0000 | 300,000.0000 | 300,000.0000 | 300,000.0000 | 300,000.0000 | 300,000.0000 | 300,000.0000 | 300,000.0000 |
| Shell Clingage Factor (bbl/1000 sqft): | 0.0015 | 0.0015 | 0.0015 | 0.0015 | 0.0015 | 0.0015 | 0.0015 | 0.0015 | 0.0015 | 0.0015 | 0.0015 | 0.0015 |
| Average Organic Liquid Density (lb/gal): | 6.6100 | 6.6100 | 6.6100 | 6.6100 | 6.6100 | 6.6100 | 6.6100 | 6.6100 | 6.6100 | 6.6100 | 6.6100 | 6.6100 |
| Tank Diameter (ft): | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 |
| Deck Fitting Losses (lb): | 16.7919 | 17.2498 | 18.6755 | 20.0727 | 21.7420 | 22.6897 | 22.9575 | 22.9236 | 22.4335 | 20.7848 | 18.7214 | 17.1887 |
| Value of Vapor Pressure Function: | 0.0167 | 0.0171 | 0.0185 | 0.0199 | 0.0216 | 0.0225 | 0.0228 | 0.0228 | 0.0223 | 0.0206 | 0.0186 | 0.0171 |
| Vapor Molecular Weight (lb/lb-mole): | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 |
| Product Factor: | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Tot. Roof Fitting Loss Fact.(lb-mole/yr): | 262.3000 | 262.3000 | 262.3000 | 262.3000 | 262.3000 | 262.3000 | 262.3000 | 262.3000 | 262.3000 | 262.3000 | 262.3000 | 262.3000 |
| Deck Seam Losses (lb): | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| Deck Seam Length (ft): | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| Deck Seam Loss per Unit Length Factor (lb-mole/ft-yr): | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| *Deck Seam Length Factor(ft/sqft):* | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| Tank Diameter (ft): | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 |
| Vapor Molecular Weight (lb/lb-mole): | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 | 46.0700 |
| Product Factor: | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 |
| Total Losses (lb): | 30.2932 | 31.0434 | 33.3796 | 35.6690 | 38.4043 | 39.9572 | 40.3960 | 40.3404 | 39.5373 | 36.8359 | 33.4548 | 30.9433 |

| Roof Fitting/Status | Quantity | Roof Fitting Loss Factors KFa(lb-mole/yr) | KFb(lb-mole/(yr mph^n)) | m | Losses(lb) |
|---|---|---|---|---|---|
| Access Hatch (24-in. Diam.)/Unbolted Cover, Ungasketed | 1 | 36.00 | 5.90 | 1.20 | 33.2710 |
| Automatic Gauge Float Well/Unbolted Cover, Ungasketed | 1 | 14.00 | 5.40 | 1.10 | 12.9387 |
| Column Well (24-in. Diam.)/Built-Up Col.-Sliding Cover, Ungask. | 1 | 47.00 | 0.00 | 0.00 | 43.4372 |
| Ladder Well (36-in. Diam.)/Sliding Cover, Ungasketed | 1 | 76.00 | 0.00 | 0.00 | 70.2389 |
| *Roof Leg or Hanger Well/Adjustable* | 9 | 7.90 | 0.00 | 0.00 | 65.7103 |
| Sample Pipe or Well (24-in. Diam.)/Slit Fabric Seal 10% Open | 1 | 12.00 | 0.00 | 0.00 | 11.0903 |
| Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask. | 1 | 6.20 | 1.20 | 0.94 | 5.7300 |

# TANKS 4.0.9d
# Emissions Report - Detail Format
# Individual Tank Emission Totals

## Emissions Report for: January, February, March, April, May, June, July, August, September, October, November, December

### HEF - Off-spec tank - Internal Floating Roof Tank

| | Losses(lbs) | | | | |
|---|---|---|---|---|---|
| Components | Rim Seal Loss | Withdrawl Loss | Deck Fitting Loss | Deck Seam Loss | Total Emissions |
| Ethyl alcohol | 154.68 | 33.34 | 242.23 | 0.00 | 430.25 |

# TANKS 4.0.9d
## Emissions Report - Summary Format
## Tank Indentification and Physical Characteristics

| | | |
|---|---|---|
| **Identification** | | |
| User Identification: | HEF - Off-spec tank | |
| City: | | |
| State: | | |
| Company: | | |
| Type of Tank: | Internal Floating Roof Tank | |
| Description: | | |
| **Tank Dimensions** | | |
| Diameter (ft): | | 25.00 |
| Volume (gallons): | | 100,000.00 |
| Turnovers: | | 36.00 |
| Self Supp. Roof? (y/n): | N | |
| No. of Columns: | | 1.00 |
| Eff. Col. Diam. (ft): | | 1.00 |
| **Paint Characteristics** | | |
| Internal Shell Condition: | Light Rust | |
| Shell Color/Shade: | White/White | |
| Shell Condition | Good | |
| Roof Color/Shade: | White/White | |
| Roof Condition: | Good | |
| **Rim-Seal System** | | |
| Primary Seal: | Vapor-mounted | |
| Secondary Seal | None | |
| **Deck Characteristics** | | |
| Deck Fitting Category: | Typical | |
| Deck Type: | Welded | |

| Deck Fitting/Status | Quantity |
|---|---|
| Access Hatch (24-in. Diam.)/Unbolted Cover, Ungasketed | 1 |
| Automatic Gauge Float Well/Unbolted Cover, Ungasketed | 1 |
| Column Well (24-in. Diam.)/Built-Up Col.-Sliding Cover, Ungask. | 1 |
| Ladder Well (36-in. Diam.)/Sliding Cover, Ungasketed | 1 |
| Roof Leg or Hanger Well/Adjustable | 9 |
| Sample Pipe or Well (24-in. Diam.)/Slit Fabric Seal 10% Open | 1 |
| Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask. | 1 |

Meterological Data used in Emissions Calculations: Fort Myers, Florida (Avg Atmospheric Pressure = 14.76 psia)

# TANKS 4.0.9d
# Emissions Report - Summary Format
# Liquid Contents of Storage Tank

## HEF - Off-spec tank - Internal Floating Roof Tank

| Mixture/Component | Month | Daily Liquid Surf. Temperature (deg F) Avg. | Min. | Max. | Liquid Bulk Temp (deg F) | Vapor Pressure (psia) Avg. | Min. | Max. | Vapor Mol. Weight. | Liquid Mass Fract. | Vapor Mass Fract. | Mol. Weight | Basis for Vapor Pressure Calculations |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Ethyl alcohol | All | 76.36 | 71.13 | 81.59 | 74.37 | 1.1310 | N/A | N/A | 46.0700 | | | 46.07 | Option 2: A=8.321, B=1718.21, C=237.52 |

# TANKS 4.0.9d
# Emissions Report - Summary Format
# Individual Tank Emission Totals

## Emissions Report for: Annual

## HEF - Off-spec tank - Internal Floating Roof Tank

| | Losses(lbs) | | | | |
|---|---|---|---|---|---|
| Components | Rim Seal Loss | Withdrawl Loss | Deck Fitting Loss | Deck Seam Loss | Total Emissions |
| Ethyl alcohol | 153.76 | 33.34 | 240.78 | 0.00 | 427.88 |

# TANKS 4.0.9d
# Emissions Report - Detail Format
# Tank Indentification and Physical Characteristics

**Identification**

| | |
|---|---|
| User Identification: | HEF - Denaturant/Gas |
| City: | |
| State: | |
| Company: | |
| Type of Tank: | Internal Floating Roof Tank |
| Description: | |

**Tank Dimensions**

| | |
|---|---|
| Diameter (ft): | 25.00 |
| Volume (gallons): | 100,000.00 |
| Turnovers: | 16.20 |
| Self Supp. Roof? (y/n): | N |

| | | |
|---|---|---|
| No. of Columns: | | 1.00 |
| Eff. Col. Diam. (ft): | | 1.00 |
| **Paint Characteristics** | | |
| Internal Shell Condition: | Light Rust | |
| Shell Color/Shade: | White/White | |
| Shell Condition | Good | |
| Roof Color/Shade: | White/White | |
| Roof Condition: | Good | |
| **Rim-Seal System** | | |
| Primary Seal: | Vapor-mounted | |
| Secondary Seal | None | |
| **Deck Characteristics** | | |
| Deck Fitting Category: | Typical | |
| Deck Type: | Welded | |

| Deck Fitting/Status | Quantity |
|---|---|
| Access Hatch (24-in. Diam.)/Unbolted Cover, Ungasketed | 1 |
| Automatic Gauge Float Well/Unbolted Cover, Ungasketed | 1 |
| Column Well (24-in. Diam.)/Built-Up Col.-Sliding Cover, Ungask. | 1 |
| Ladder Well (36-in. Diam.)/Sliding Cover, Ungasketed | 1 |
| Roof Leg or Hanger Well/Adjustable | 9 |
| Sample Pipe or Well (24-in. Diam.)/Slit Fabric Seal 10% Open | 1 |
| Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask. | 1 |

Meterological Data used in Emissions Calculations: Fort Myers, Florida (Avg Atmospheric Pressure = 14.76 psia)

# TANKS 4.0.9d
# Emissions Report - Detail Format
# Liquid Contents of Storage Tank

## HEF - Denaturant/Gas - Internal Floating Roof Tank

| Mixture/Component | Month | Daily Liquid Surf. Temperature (deg F) Avg. | Min. | Max. | Liquid Bulk Temp (deg F) | Vapor Pressure (psia) Avg. | Min. | Max. | Vapor Mol. Weight. | Liquid Mass Fract. | Vapor Mass Fract. | Mol. Weight | Basis for Vapor Pressure Calculations |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Gasoline (RVP 12) | Jan | 71.05 | 66.05 | 76.05 | 74.37 | 7.7958 | N/A | N/A | 64.0000 | | | 92.00 | Option 4: RVP=12, ASTM Slope=3 |
| Gasoline (RVP 12) | Feb | 71.85 | 66.53 | 77.16 | 74.37 | 7.9089 | N/A | N/A | 64.0000 | | | 92.00 | Option 4: RVP=12, ASTM Slope=3 |
| Gasoline (RVP 12) | Mar | 74.21 | 68.52 | 79.90 | 74.37 | 8.2521 | N/A | N/A | 64.0000 | | | 92.00 | Option 4: RVP=12, ASTM Slope=3 |
| Gasoline (RVP 12) | Apr | 76.37 | 70.10 | 82.64 | 74.37 | 8.5763 | N/A | N/A | 64.0000 | | | 92.00 | Option 4: RVP=12, ASTM Slope=3 |
| Gasoline (RVP 12) | May | 78.78 | 72.66 | 84.90 | 74.37 | 8.9494 | N/A | N/A | 64.0000 | | | 92.00 | Option 4: RVP=12, ASTM Slope=3 |
| Gasoline (RVP 12) | Jun | 80.07 | 74.78 | 85.37 | 74.37 | 9.1550 | N/A | N/A | 64.0000 | | | 92.00 | Option 4: RVP=12, ASTM Slope=3 |
| Gasoline (RVP 12) | Jul | 80.43 | 75.36 | 85.50 | 74.37 | 9.2123 | N/A | N/A | 64.0000 | | | 92.00 | Option 4: RVP=12, ASTM Slope=3 |
| Gasoline (RVP 12) | Aug | 80.38 | 75.43 | 85.34 | 74.37 | 9.2050 | N/A | N/A | 64.0000 | | | 92.00 | Option 4: RVP=12, ASTM Slope=3 |
| Gasoline (RVP 12) | Sep | 79.73 | 75.15 | 84.31 | 74.37 | 9.0998 | N/A | N/A | 64.0000 | | | 92.00 | Option 4: RVP=12, ASTM Slope=3 |
| Gasoline (RVP 12) | Oct | 77.42 | 72.72 | 82.12 | 74.37 | 8.7373 | N/A | N/A | 64.0000 | | | 92.00 | Option 4: RVP=12, ASTM Slope=3 |
| Gasoline (RVP 12) | Nov | 74.28 | 69.40 | 79.16 | 74.37 | 8.2630 | N/A | N/A | 64.0000 | | | 92.00 | Option 4: RVP=12, ASTM Slope=3 |
| Gasoline (RVP 12) | Dec | 71.74 | 66.87 | 76.62 | 74.37 | 7.8939 | N/A | N/A | 64.0000 | | | 92.00 | Option 4: RVP=12, ASTM Slope=3 |

# TANKS 4.0.9d
# Emissions Report - Detail Format
# Detail Calculations (AP-42)

## HEF - Denaturant/Gas - Internal Floating Roof Tank

| Month: | January | February | March | April | May | June | July | August | September | October | November | December |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Rim Seal Losses (lb): | 165.7930 | 169.3212 | 180.3586 | 191.2745 | 204.4895 | 212.0935 | 214.2571 | 213.9825 | 210.0291 | 196.8865 | 180.7155 | 168.8501 |
| Seal Factor A (lb-mole/ft-yr): | 6.7000 | 6.7000 | 6.7000 | 6.7000 | 6.7000 | 6.7000 | 6.7000 | 6.7000 | 6.7000 | 6.7000 | 6.7000 | 6.7000 |
| Seal Factor B (lb-mole/ft-yr (mph)^n): | 0.2000 | 0.2000 | 0.2000 | 0.2000 | 0.2000 | 0.2000 | 0.2000 | 0.2000 | 0.2000 | 0.2000 | 0.2000 | 0.2000 |
| Value of Vapor Pressure Function: | 0.1856 | 0.1895 | 0.2019 | 0.2141 | 0.2289 | 0.2374 | 0.2398 | 0.2395 | 0.2351 | 0.2204 | 0.2023 | 0.1890 |
| Vapor Pressure at Daily Average Liquid Surface Temperature (psia): | 7.7958 | 7.9089 | 8.2521 | 8.5763 | 8.9494 | 9.1550 | 9.2123 | 9.2050 | 9.0998 | 8.7373 | 8.2630 | 7.8939 |
| Tank Diameter (ft): | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 |
| Vapor Molecular Weight (lb/lb-mole): | 64.0000 | 64.0000 | 64.0000 | 64.0000 | 64.0000 | 64.0000 | 64.0000 | 64.0000 | 64.0000 | 64.0000 | 64.0000 | 64.0000 |
| Product Factor: | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 |
| Withdrawal Losses (lb): | 1.0592 | 1.0592 | 1.0592 | 1.0592 | 1.0592 | 1.0592 | 1.0592 | 1.0592 | 1.0592 | 1.0592 | 1.0592 | 1.0592 |
| Number of Columns: | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 |
| Effective Column Diameter (ft): | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 |
| Net Throughput (gal/mo.): | 135,000.0000 | 135,000.0000 | 135,000.0000 | 135,000.0000 | 135,000.0000 | 135,000.0000 | 135,000.0000 | 135,000.0000 | 135,000.0000 | 135,000.0000 | 135,000.0000 | 135,000.0000 |
| Shell Clingage Factor (bbl/1000 sqft): | 0.0015 | 0.0015 | 0.0015 | 0.0015 | 0.0015 | 0.0015 | 0.0015 | 0.0015 | 0.0015 | 0.0015 | 0.0015 | 0.0015 |
| Average Organic Liquid Density (lb/gal): | 5.6000 | 5.6000 | 5.6000 | 5.6000 | 5.6000 | 5.6000 | 5.6000 | 5.6000 | 5.6000 | 5.6000 | 5.6000 | 5.6000 |
| Tank Diameter (ft): | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 |
| Deck Fitting Losses (lb): | 259.6269 | 265.1520 | 282.4362 | 299.5302 | 320.2244 | 332.1321 | 335.5202 | 335.0902 | 328.8994 | 308.3184 | 282.9950 | 264.4143 |
| Value of Vapor Pressure Function: | 0.1856 | 0.1895 | 0.2019 | 0.2141 | 0.2289 | 0.2374 | 0.2398 | 0.2395 | 0.2351 | 0.2204 | 0.2023 | 0.1890 |
| Vapor Molecular Weight (lb/lb-mole): | 64.0000 | 64.0000 | 64.0000 | 64.0000 | 64.0000 | 64.0000 | 64.0000 | 64.0000 | 64.0000 | 64.0000 | 64.0000 | 64.0000 |
| Product Factor: | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Tot. Roof Fitting Loss Fact.(lb-mole/yr): | 262.3000 | 262.3000 | 262.3000 | 262.3000 | 262.3000 | 262.3000 | 262.3000 | 262.3000 | 262.3000 | 262.3000 | 262.3000 | 262.3000 |
| Deck Seam Losses (lb): | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| Deck Seam Length (ft): | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| Deck Seam Loss per Unit Length Factor (lb-mole/ft-yr): | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| Deck Seam Length Factor(ft/sqft): | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| Tank Diameter (ft): | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 | 25.0000 |
| Vapor Molecular Weight (lb/lb-mole): | 64.0000 | 64.0000 | 64.0000 | 64.0000 | 64.0000 | 64.0000 | 64.0000 | 64.0000 | 64.0000 | 64.0000 | 64.0000 | 64.0000 |
| Product Factor: | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 | 1.0000 |
| Total Losses (lb): | 426.4790 | 435.5323 | 463.8539 | 491.8638 | 525.7731 | 545.2848 | 550.8365 | 550.1319 | 539.9877 | 506.2641 | 464.7697 | 434.3236 |

| Roof Fitting/Status | Quantity | Roof Fitting Loss Factors KFa(lb-mole/yr) | KFb(lb-mole/(yr mph^n)) | m | Losses(lb) |
|---|---|---|---|---|---|
| Access Hatch (24-in. Diam.)/Unbolted Cover, Ungasketed | 1 | 36.00 | 5.90 | 1.20 | 496.3717 |
| Automatic Gauge Float Well/Unbolted Cover, Ungasketed | 1 | 14.00 | 5.40 | 1.10 | 193.0334 |
| Column Well (24-in. Diam.)/Built-Up Col.-Sliding Cover, Ungask. | 1 | 47.00 | 0.00 | 0.00 | 648.0408 |
| Ladder Well (36-in. Diam.)/Sliding Cover, Ungasketed | 1 | 76.00 | 0.00 | 0.00 | 1,047.8958 |
| Roof Leg or Hanger Well/Adjustable | 9 | 7.90 | 0.00 | 0.00 | 980.3341 |
| Sample Pipe or Well (24-in. Diam.)/Slit Fabric Seal 10% Open | 1 | 12.00 | 0.00 | 0.00 | 165.4572 |
| Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask. | 1 | 6.20 | 1.20 | 0.94 | 85.4862 |

# TANKS 4.0.9d
# Emissions Report - Detail Format
# Individual Tank Emission Totals

## Emissions Report for: January, February, March, April, May, June, July, August, September, October, November, December

### HEF - Denaturant/Gas - Internal Floating Roof Tank

| | Losses(lbs) | | | | |
|---|---|---|---|---|---|
| Components | Rim Seal Loss | Withdrawl Loss | Deck Fitting Loss | Deck Seam Loss | Total Emissions |
| Gasoline (RVP 12) | 2,308.05 | 12.71 | 3,614.34 | 0.00 | 5,935.10 |

# TANKS 4.0.9d
## Emissions Report - Summary Format
## Tank Indentification and Physical Characteristics

| | |
|---|---|
| **Identification** | |
| User Identification: | HEF - Denaturant/Gas |
| City: | |
| State: | |
| Company: | |
| Type of Tank: | Internal Floating Roof Tank |
| Description: | |
| **Tank Dimensions** | |
| Diameter (ft): | 25.00 |
| Volume (gallons): | 100,000.00 |
| Turnovers: | 16.20 |
| Self Supp. Roof? (y/n): | N |
| No. of Columns: | 1.00 |
| Eff. Col. Diam. (ft): | 1.00 |
| **Paint Characteristics** | |
| Internal Shell Condition: | Light Rust |
| Shell Color/Shade: | White/White |
| Shell Condition | Good |
| Roof Color/Shade: | White/White |
| Roof Condition: | Good |
| **Rim-Seal System** | |
| Primary Seal: | Vapor-mounted |
| Secondary Seal | None |
| **Deck Characteristics** | |
| Deck Fitting Category: | Typical |
| Deck Type: | Welded |

| Deck Fitting/Status | Quantity |
|---|---|
| Access Hatch (24-in. Diam.)/Unbolted Cover, Ungasketed | 1 |
| Automatic Gauge Float Well/Unbolted Cover, Ungasketed | 1 |
| Column Well (24-in. Diam.)/Built-Up Col.-Sliding Cover, Ungask. | 1 |
| Ladder Well (36-in. Diam.)/Sliding Cover, Ungasketed | 1 |
| Roof Leg or Hanger Well/Adjustable | 9 |
| Sample Pipe or Well (24-in. Diam.)/Slit Fabric Seal 10% Open | 1 |
| Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask. | 1 |

Meterological Data used in Emissions Calculations: Fort Myers, Florida (Avg Atmospheric Pressure = 14.76 psia)

# TANKS 4.0.9d
## Emissions Report - Summary Format
## Liquid Contents of Storage Tank

### HEF - Denaturant/Gas - Internal Floating Roof Tank

| Mixture/Component | Month | Daily Liquid Surf. Temperature (deg F) Avg. | Min. | Max. | Liquid Bulk Temp (deg F) | Vapor Pressure (psia) Avg. | Min. | Max. | Vapor Mol. Weight. | Liquid Mass Fract. | Vapor Mass Fract. | Mol. Weight | Basis for Vapor Pressure Calculations |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Gasoline (RVP 12) | All | 76.36 | 71.13 | 81.59 | 74.37 | 8.5746 | N/A | N/A | 64.0000 | | | 92.00 | Option 4: RVP=12, ASTM Slope=3 |

# TANKS 4.0.9d
## Emissions Report - Summary Format
## Individual Tank Emission Totals

## Emissions Report for: Annual

### HEF - Denaturant/Gas - Internal Floating Roof Tank

| | Losses(lbs) | | | | |
|---|---|---|---|---|---|
| Components | Rim Seal Loss | Withdrawl Loss | Deck Fitting Loss | Deck Seam Loss | Total Emissions |
| Gasoline (RVP 12) | 2,294.60 | 12.71 | 3,593.28 | 0.00 | 5,900.59 |

# APPENDIX E

# AP-42 EMISSION FACTOR DOCUMENTATION

## 1.3 Fuel Oil Combustion

### 1.3.1 General[1-3]

Two major categories of fuel oil are burned by combustion sources: distillate oils and residual oils. These oils are further distinguished by grade numbers, with Nos. 1 and 2 being distillate oils; Nos. 5 and 6 being residual oils; and No. 4 being either distillate oil or a mixture of distillate and residual oils. No. 6 fuel oil is sometimes referred to as Bunker C. Distillate oils are more volatile and less viscous than residual oils. They have negligible nitrogen and ash contents and usually contain less than 0.3 percent sulfur (by weight). Distillate oils are used mainly in domestic and small commercial applications, and include kerosene and diesel fuels. Being more viscous and less volatile than distillate oils, the heavier residual oils (Nos. 5 and 6) may need to be heated for ease of handling and to facilitate proper atomization. Because residual oils are produced from the residue remaining after the lighter fractions (gasoline, kerosene, and distillate oils) have been removed from the crude oil, they contain significant quantities of ash, nitrogen, and sulfur. Residual oils are used mainly in utility, industrial, and large commercial applications.

### 1.3.2 Firing Practices[4]

The major boiler configurations for fuel oil-fired combustors are watertube, firetube, cast iron, and tubeless design. Boilers are classified according to design and orientation of heat transfer surfaces, burner configuration, and size. These factors can all strongly influence emissions as well as the potential for controlling emissions.

Watertube boilers are used in a variety of applications ranging from supplying large amounts of process steam to providing space heat for industrial facilities. In a watertube boiler, combustion heat is transferred to water flowing through tubes which line the furnace walls and boiler passes. The tube surfaces in the furnace (which houses the burner flame) absorb heat primarily by radiation from the flames. The tube surfaces in the boiler passes (adjacent to the primary furnace) absorb heat primarily by convective heat transfer.

Firetube boilers are used primarily for heating systems, industrial process steam generators, and portable power boilers. In firetube boilers, the hot combustion gases flow through the tubes while the water being heated circulates outside of the tubes. At high pressures and when subjected to large variations in steam demand, firetube units are more susceptible to structural failure than watertube boilers. This is because the high-pressure steam in firetube units is contained by the boiler walls rather than by multiple small-diameter watertubes, which are inherently stronger. As a consequence, firetube boilers are typically small and are used primarily where boiler loads are relatively constant. Nearly all firetube boilers are sold as packaged units because of their relatively small size.

A cast iron boiler is one in which combustion gases rise through a vertical heat exchanger and out through an exhaust duct. Water in the heat exchanger tubes is heated as it moves upward through the tubes. Cast iron boilers produce low pressure steam or hot water, and generally burn oil or natural gas. They are used primarily in the residential and commercial sectors.

Another type of heat transfer configuration used on smaller boilers is the tubeless design. This design incorporates nested pressure vessels with water in between the shells. Combustion gases are fired into the inner pressure vessel and are then sometimes recirculated outside the second vessel.

Table 1.3-1. CRITERIA POLLUTANT EMISSION FACTORS FOR FUEL OIL COMBUSTION[a]

| Firing Configuration (SCC)[a] | $SO_2$[b] | | $SO_3$[c] | | $NO_x$[d] | | CO[e] | | Filterable PM[f] | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Emission Factor ($lb/10^3$ gal) | EMISSION FACTOR RATING | Emission Factor ($lb/10^3$ gal) | EMISSION FACTOR RATING | Emission Factor ($lb/10^3$ gal) | EMISSION FACTOR RATING | Emission Factor ($lb/10^3$ gal) | EMISSION FACTOR RATING | Emission Factor ($lb/10^3$ gal) | EMISSION FACTOR RATING |
| Boilers > 100 Million Btu/hr | | | | | | | | | | |
| No. 6 oil fired, normal firing (1-01-004-01), (1-02-004-01), (1-03-004-01) | 157S | A | 5.7S | C | 47 | A | 5 | A | 9.19(S)+3.22 | A |
| No. 6 oil fired, normal firing, low $NO_x$ burner (1-01-004-01), (1-02-004-01) | 157S | A | 5.7S | C | 40 | B | 5 | A | 9.19(S)+3.22 | A |
| No. 6 oil fired, tangential firing, (1-01-004-04) | 157S | A | 5.7S | C | 32 | A | 5 | A | 9.19(S)+3.22 | A |
| No. 6 oil fired, tangential firing, low $NO_x$ burner (1-01-004-04) | 157S | A | 5.7S | C | 26 | E | 5 | A | 9.19(S)+3.22 | A |
| No. 5 oil fired, normal firing (1-01-004-05), (1-02-004-04) | 157S | A | 5.7S | C | 47 | B | 5 | A | 10 | B |
| No. 5 oil fired, tangential firing (1-01-004-06) | 157S | A | 5.7S | C | 32 | B | 5 | A | 10 | B |
| No. 4 oil fired, normal firing (1-01-005-04), (1-02-005-04) | 150S | A | 5.7S | C | 47 | B | 5 | A | 7 | B |
| No. 4 oil fired, tangential firing (1-01-005-05) | 150S | A | 5.7S | C | 32 | B | 5 | A | 7 | B |
| No. 2 oil fired (1-01-005-01), (1-02-005-01), (1-03-005-01) | 157S | A | 5.7S | C | 24 | D | 5 | A | 2 | A |
| No.2 oil fired, LNB/FGR, (1-01-005-01), (1-02-005-01), (1-03-005-01) | 157S | A | 5.7S | A | 10 | D | 5 | A | 2 | A |

Table 1.3-1. (cont.)

| Firing Configuration (SCC)[a] | $SO_2$[b] | | $SO_3$[c] | | $NO_x$[d] | | CO[e] | | Filterable PM[f] | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Emission Factor ($lb/10^3$ gal) | EMISSION FACTOR RATING | Emission Factor ($lb/10^3$ gal) | EMISSION FACTOR RATING | Emission Factor ($lb/10^3$ gal) | EMISSION FACTOR RATING | Emission Factor ($lb/10^3$ gal) | EMISSION FACTOR RATING | Emission Factor ($lb/10^3$ gal) | EMISSION FACTOR RATING |
| Boilers < 100 Million Btu/hr | | | | | | | | | | |
| No. 6 oil fired (1-02-004-02/03) (1-03-004-02/03) | 157S | A | 2S | A | 55 | A | 5 | A | 10 | B |
| No. 5 oil fired (1-03-004-04) | 157S | A | 2S | A | 55 | A | 5 | A | 9.19(S)+3.22 | A |
| No. 4 oil fired (1-03-005-04) | 150S | A | 2S | A | 20 | A | 5 | A | 7 | B |
| Distillate oil fired (1-02-005-02/03) (1-03-005-02/03) | 142S | A | 2S | A | 20 | A | 5 | A | 2 | A |
| Residential furnace (A2104004/A2104011) | 142S | A | 2S | A | 18 | A | 5 | A | 0.4[g] | B |

[a] To convert from $lb/10^3$ gal to $kg/10^3$ L, multiply by 0.120. SCC = Source Classification Code.

[b] References 1-2,6-9,14,56-60. S indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then S = 1.

[c] References 1-2,6-8,16,57-60. S indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then S = 1.

[d] References 6-7,15,19,22,56-62. Expressed as $NO_2$. Test results indicate that at least 95% by weight of $NO_x$ is NO for all boiler types except residential furnaces, where about 75% is NO. For utility vertical fired boilers use 105 $lb/10^3$ gal at full load and normal (>15%) excess air. Nitrogen oxides emissions from residual oil combustion in industrial and commercial boilers are related to fuel nitrogen content, estimated by the following empirical relationship: lb $NO_2/10^3$ gal = 20.54 + 104.39(N), where N is the weight % of nitrogen in the oil. For example, if the fuel is 1% nitrogen, then N = 1.

[e] References 6-8,14,17-19,56-61. CO emissions may increase by factors of 10 to 100 if the unit is improperly operated or not well maintained.

[f] References 6-8,10,13-15,56-60,62-63. Filterable PM is that particulate collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train. Particulate emission factors for residual oil combustion are, on average, a function of fuel oil sulfur content where S is the weight % of sulfur in oil. For example, if fuel oil is 1% sulfur, then S = 1.

[g] Based on data from new burner designs. Pre-1970's burner designs may emit filterable PM as high as 3.0 $lb/10^3$ gal.

Table 1.3-2. CONDENSABLE PARTICULATE MATTER EMISSION FACTORS FOR OIL COMBUSTION[a]

| Firing Configuration[b] (SCC) | Controls | CPM - TOT[c, d] | | CPM - IOR[c, d] | | CPM - ORG[c, d] | |
|---|---|---|---|---|---|---|---|
| | | Emission Factor ($lb/10^3$ gal) | EMISSION FACTOR RATING | Emission Factor ($lb/10^3$ gal) | EMISSION FACTOR RATING | Emission Factor ($lb/10^3$ gal) | EMISSION FACTOR RATING |
| No. 2 oil fired (1-01-005-01, 1-02-005-01, 1-03-005-01) | All controls, or uncontrolled | 1.3[d, e] | D | 65% of CPM-TOT emission factor[c] | D | 35% of CPM-TOT emission factor[c] | D |
| No. 6 oil fired (1-01-004-01/04, 1-02-004-01, 1-03-004-01) | All controls, or uncontrolled | 1.5[f] | D | 85% of CPM-TOT emission factor[d] | E | 15% of CPM-TOT emission factor[d] | E |

[a] All condensable PM is assumed to be less than 1.0 micron in diameter.
[b] No data are available for numbers 3, 4, and 5 oil. For number 3 oil, use the factors provided for number 2 oil. For numbers 4 and 5 oil, use the factors provided for number 6 oil.
[c] CPM-TOT = total condensable particulate matter.
CPM-IOR = inorganic condensable particulate matter.
CPM-ORG = organic condensable particulate matter.
[d] To convert to lb/MMBtu of No. 2 oil, divide by 140 MMBtu/$10^3$ gal. To convert to lb/MMBtu of No. 6 oil, divide by 150 MMBtu/$10^3$ gal.
[e] References: 76-78.
[f] References: 79-82.

Table 1.3-3. EMISSION FACTORS FOR TOTAL ORGANIC COMPOUNDS (TOC), METHANE, AND NONMETHANE TOC (NMTOC) FROM UNCONTROLLED FUEL OIL COMBUSTION[a]

EMISSION FACTOR RATING: A

| Firing Configuration (SCC) | TOC[b] Emission Factor ($lb/10^3$ gal) | Methane[b] Emission Factor ($lb/10^3$ gal) | NMTOC[b] Emission Factor ($lb/10^3$ gal) |
|---|---|---|---|
| Utility boilers | | | |
| No. 6 oil fired, normal firing (1-01-004-01) | 1.04 | 0.28 | 0.76 |
| No. 6 oil fired, tangential firing (1-01-004-04) | 1.04 | 0.28 | 0.76 |
| No. 5 oil fired, normal firing (1-01-004-05) | 1.04 | 0.28 | 0.76 |
| No. 5 oil fired, tangential firing (1-01-004-06) | 1.04 | 0.28 | 0.76 |
| No. 4 oil fired, normal firing (1-01-005-04) | 1.04 | 0.28 | 0.76 |
| No. 4 oil fired, tangential firing (1-01-005-05) | 1.04 | 0.28 | 0.76 |
| Industrial boilers | | | |
| No. 6 oil fired (1-02-004-01/02/03) | 1.28 | 1.00 | 0.28 |
| No. 5 oil fired (1-02-004-04) | 1.28 | 1.00 | 0.28 |
| Distillate oil fired (1-02-005-01/02/03) | 0.252 | 0.052 | 0.2 |
| No. 4 oil fired (1-02-005-04) | 0.252 | 0.052 | 0.2 |
| Commercial/institutional/residential combustors | | | |
| No. 6 oil fired (1-03-004-01/02/03) | 1.605 | 0.475 | 1.13 |
| No. 5 oil fired (1-03-004-04) | 1.605 | 0.475 | 1.13 |
| Distillate oil fired (1-03-005-01/02/03) | 0.556 | 0.216 | 0.34 |
| No. 4 oil fired (1-03-005-04) | 0.556 | 0.216 | 0.34 |
| Residential furnace (A2104004/A2104011) | 2.493 | 1.78 | 0.713 |

[a] To convert from $lb/10^3$ gal to $kg/10^3$ L, multiply by 0.12. SCC = Source Classification Code.

[b] References 29-32. Volatile organic compound emissions can increase by several orders of magnitude if the boiler is improperly operated or is not well maintained.

Table 1.3-9. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM FUEL OIL COMBUSTION[a]

| Organic Compound | Average Emission Factor[b] (lb/$10^3$ Gal) | EMISSION FACTOR RATING |
|---|---|---|
| Benzene | 2.14E-04 | C |
| Ethylbenzene | 6.36E-05[c] | E |
| Formaldehyde[d] | 3.30E-02 | C |
| Naphthalene | 1.13E-03 | C |
| 1,1,1-Trichloroethane | 2.36E-04[c] | E |
| Toluene | 6.20E-03 | D |
| o-Xylene | 1.09E-04[c] | E |
| Acenaphthene | 2.11E-05 | C |
| Acenaphthylene | 2.53E-07 | D |
| Anthracene | 1.22E-06 | C |
| Benz(a)anthracene | 4.01E-06 | C |
| Benzo(b,k)fluoranthene | 1.48E-06 | C |
| Benzo(g,h,i)perylene | 2.26E-06 | C |
| Chrysene | 2.38E-06 | C |
| Dibenzo(a,h) anthracene | 1.67E-06 | D |
| Fluoranthene | 4.84E-06 | C |
| Fluorene | 4.47E-06 | C |
| Indo(1,2,3-cd)pyrene | 2.14E-06 | C |
| Phenanthrene | 1.05E-05 | C |
| Pyrene | 4.25E-06 | C |
| OCDD | 3.10E-09[c] | E |

[a] Data are for residual oil fired boilers, Source Classification Codes (SCCs) 1-01-004-01/04.

[b] References 64-72. To convert from lb/$10^3$ gal to kg/$10^3$ L, multiply by 0.12.

[c] Based on data from one source test (Reference 67).

[d] The formaldehyde number presented here is based only on data from utilities using No. 6 oil. The number presented in Table 1.3-7 is based on utility, commercial, and industrial boilers.

Table 1.3-10. EMISSION FACTORS FOR TRACE ELEMENTS FROM DISTILLATE FUEL OIL COMBUSTION SOURCES[a]

EMISSION FACTOR RATING: E

| Firing Configuration (SCC) | Emission Factor (lb/$10^{12}$ Btu) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | As | Be | Cd | Cr | Cu | Pb | Hg | Mn | Ni | Se | Zn |
| Distillate oil fired (1-01-005-01, 1-02-005-01, 1-03-005-01) | 4 | 3 | 3 | 3 | 6 | 9 | 3 | 6 | 3 | 15 | 4 |

[a] Data are for distillate oil fired boilers, SCC codes 1-01-005-01, 1-02-005-01, and 1-03-005-01. References 29-32, 40-44 and 83. To convert from lb/$10^{12}$ Btu to pg/J, multiply by 0.43.

Table 1.3-11. EMISSION FACTORS FOR METALS FROM UNCONTROLLED NO. 6 FUEL OIL COMBUSTION[a]

| Metal | Average Emission Factor[b, d] (lb/$10^3$ Gal) | EMISSION FACTOR RATING |
|---|---|---|
| Antimony | 5.25E-03[c] | E |
| Arsenic | 1.32E-03 | C |
| Barium | 2.57E-03 | D |
| Beryllium | 2.78E-05 | C |
| Cadmium | 3.98E-04 | C |
| Chloride | 3.47E-01 | D |
| Chromium | 8.45E-04 | C |
| Chromium VI | 2.48E-04 | C |
| Cobalt | 6.02E-03 | D |
| Copper | 1.76E-03 | C |
| Fluoride | 3.73E-02 | D |
| Lead | 1.51E-03 | C |
| Manganese | 3.00E-03 | C |
| Mercury | 1.13E-04 | C |
| Molybdenum | 7.87E-04 | D |
| Nickel | 8.45E-02 | C |
| Phosphorous | 9.46E-03 | D |
| Selenium | 6.83E-04 | C |
| Vanadium | 3.18E-02 | D |
| Zinc | 2.91E-02 | D |

[a] Data are for residual oil fired boilers, Source Classification Codes (SCCs) 1-01-004-01/04.

[b] References 64-72. 18 of 19 sources were uncontrolled and 1 source was controlled with low efficiency ESP. To convert from lb/$10^3$ gal to kg/$10^3$ L, multiply by 0.12.

[c] References 29-32,40-44.

[d] For oil/water mixture, reduce factors in proportion to water content of the fuel (due to dilution). To adjust the listed values for water content, multiply the listed value by 1-decimal fraction of water (ex: For fuel with 9 percent water by volume, multiply by 1-0.9=.91).

## 1.4 Natural Gas Combustion

### 1.4.1 General[1-2]

Natural gas is one of the major combustion fuels used throughout the country. It is mainly used to generate industrial and utility electric power, produce industrial process steam and heat, and heat residential and commercial space. Natural gas consists of a high percentage of methane (generally above 85 percent) and varying amounts of ethane, propane, butane, and inerts (typically nitrogen, carbon dioxide, and helium). The average gross heating value of natural gas is approximately 1,020 British thermal units per standard cubic foot (Btu/scf), usually varying from 950 to 1,050 Btu/scf.

### 1.4.2 Firing Practices[3-5]

There are three major types of boilers used for natural gas combustion in commercial, industrial, and utility applications: watertube, firetube, and cast iron. Watertube boilers are designed to pass water through the inside of heat transfer tubes while the outside of the tubes is heated by direct contact with the hot combustion gases and through radiant heat transfer. The watertube design is the most common in utility and large industrial boilers. Watertube boilers are used for a variety of applications, ranging from providing large amounts of process steam, to providing hot water or steam for space heating, to generating high-temperature, high-pressure steam for producing electricity. Furthermore, watertube boilers can be distinguished either as field erected units or packaged units.

Field erected boilers are boilers that are constructed on site and comprise the larger sized watertube boilers. Generally, boilers with heat input levels greater than 100 MMBtu/hr, are field erected. Field erected units usually have multiple burners and, given the customized nature of their construction, also have greater operational flexibility and $NO_x$ control options. Field erected units can also be further categorized as wall-fired or tangential-fired. Wall-fired units are characterized by multiple individual burners located on a single wall or on opposing walls of the furnace while tangential units have several rows of air and fuel nozzles located in each of the four corners of the boiler.

Package units are constructed off-site and shipped to the location where they are needed. While the heat input levels of packaged units may range up to 250 MMBtu/hr, the physical size of these units are constrained by shipping considerations and generally have heat input levels less than 100 MMBtu/hr. Packaged units are always wall-fired units with one or more individual burners. Given the size limitations imposed on packaged boilers, they have limited operational flexibility and cannot feasibly incorporate some $NO_x$ control options.

Firetube boilers are designed such that the hot combustion gases flow through tubes, which heat the water circulating outside of the tubes. These boilers are used primarily for space heating systems, industrial process steam, and portable power boilers. Firetube boilers are almost exclusively packaged units. The two major types of firetube units are Scotch Marine boilers and the older firebox boilers. In cast iron boilers, as in firetube boilers, the hot gases are contained inside the tubes and the water being heated circulates outside the tubes. However, the units are constructed of cast iron rather than steel. Virtually all cast iron boilers are constructed as package boilers. These boilers are used to produce either low-pressure steam or hot water, and are most commonly used in small commercial applications.

Natural gas is also combusted in residential boilers and furnaces. Residential boilers and furnaces generally resemble firetube boilers with flue gas traveling through several channels or tubes with water or air circulated outside the channels or tubes.

Table 1.4-1. EMISSION FACTORS FOR NITROGEN OXIDES ($NO_x$) AND CARBON MONOXIDE (CO) FROM NATURAL GAS COMBUSTION[a]

| Combustor Type (MMBtu/hr Heat Input) [SCC] | $NO_x$[b] Emission Factor (lb/$10^6$ scf) | $NO_x$[b] Emission Factor Rating | CO Emission Factor (lb/$10^6$ scf) | CO Emission Factor Rating |
|---|---|---|---|---|
| Large Wall-Fired Boilers (>100) [1-01-006-01, 1-02-006-01, 1-03-006-01] | | | | |
| Uncontrolled (Pre-NSPS)[c] | 280 | A | 84 | B |
| Uncontrolled (Post-NSPS)[c] | 190 | A | 84 | B |
| Controlled - Low $NO_x$ burners | 140 | A | 84 | B |
| Controlled - Flue gas recirculation | 100 | D | 84 | B |
| Small Boilers (<100) [1-01-006-02, 1-02-006-02, 1-03-006-02, 1-03-006-03] | | | | |
| Uncontrolled | 100 | B | 84 | B |
| Controlled - Low $NO_x$ burners | 50 | D | 84 | B |
| Controlled - Low $NO_x$ burners/Flue gas recirculation | 32 | C | 84 | B |
| Tangential-Fired Boilers (All Sizes) [1-01-006-04] | | | | |
| Uncontrolled | 170 | A | 24 | C |
| Controlled - Flue gas recirculation | 76 | D | 98 | D |
| Residential Furnaces (<0.3) [No SCC] | | | | |
| Uncontrolled | 94 | B | 40 | B |

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. To convert from lb/$10^6$ scf to kg/$10^6$ $m^3$, multiply by 16. Emission factors are based on an average natural gas higher heating value of 1,020 Btu/scf. To convert from lb/$10^6$ scf to lb/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. SCC = Source Classification Code. ND = no data. NA = not applicable.

[b] Expressed as $NO_2$. For large and small wall fired boilers with SNCR control, apply a 24 percent reduction to the appropriate $NO_x$ emission factor. For tangential-fired boilers with SNCR control, apply a 13 percent reduction to the appropriate $NO_x$ emission factor.

[c] NSPS=New Source Performance Standard as defined in 40 CFR 60 Subparts D and Db. Post-NSPS units are boilers with greater than 250 MMBtu/hr of heat input that commenced construction modification, or reconstruction after August 17, 1971, and units with heat input capacities between 100 and 250 MMBtu/hr that commenced construction modification, or reconstruction after June 19, 1984.

TABLE 1.4-2. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM NATURAL GAS COMBUSTION[a]

| Pollutant | Emission Factor ($lb/10^6$ scf) | Emission Factor Rating |
|---|---|---|
| $CO_2$[b] | 120,000 | A |
| Lead | 0.0005 | D |
| $N_2O$ (Uncontrolled) | 2.2 | E |
| $N_2O$ (Controlled-low-$NO_X$ burner) | 0.64 | E |
| PM (Total)[c] | 7.6 | D |
| PM (Condensable)[c] | 5.7 | D |
| PM (Filterable)[c] | 1.9 | B |
| $SO_2$[d] | 0.6 | A |
| TOC | 11 | B |
| Methane | 2.3 | B |
| VOC | 5.5 | C |

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from $lb/10^6$ scf to $kg/10^6$ $m^3$, multiply by 16. To convert from $lb/10^6$ scf to 1b/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. TOC = Total Organic Compounds. VOC = Volatile Organic Compounds.

[b] Based on approximately 100% conversion of fuel carbon to $CO_2$. $CO_2[lb/10^6 \text{ scf}] = (3.67)$ (CON) (C)(D), where CON = fractional conversion of fuel carbon to $CO_2$, C = carbon content of fuel by weight (0.76), and D = density of fuel, $4.2 \times 10^4$ $lb/10^6$ scf.

[c] All PM (total, condensible, and filterable) is assumed to be less than 1.0 micrometer in diameter. Therefore, the PM emission factors presented here may be used to estimate $PM_{10}$, $PM_{2.5}$ or $PM_1$ emissions. Total PM is the sum of the filterable PM and condensible PM. Condensible PM is the particulate matter collected using EPA Method 202 (or equivalent). Filterable PM is the particulate matter collected on, or prior to, the filter of an EPA Method 5 (or equivalent) sampling train.

[d] Based on 100% conversion of fuel sulfur to $SO_2$.
Assumes sulfur content is natural gas of 2,000 grains/$10^6$ scf. The $SO_2$ emission factor in this table can be converted to other natural gas sulfur contents by multiplying the $SO_2$ emission factor by the ratio of the site-specific sulfur content (grains/$10^6$ scf) to 2,000 grains/$10^6$ scf.

TABLE 1.4-3. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM NATURAL GAS COMBUSTION[a]

| CAS No. | Pollutant | Emission Factor (lb/$10^6$ scf) | Emission Factor Rating |
|---|---|---|---|
| 91-57-6 | 2-Methylnaphthalene[b, c] | 2.4E-05 | D |
| 56-49-5 | 3-Methylchloranthrene[b, c] | <1.8E-06 | E |
| | 7,12-Dimethylbenz(a)anthracene[b,c] | <1.6E-05 | E |
| 83-32-9 | Acenaphthene[b,c] | <1.8E-06 | E |
| 203-96-8 | Acenaphthylene[b,c] | <1.8E-06 | E |
| 120-12-7 | Anthracene[b,c] | <2.4E-06 | E |
| 56-55-3 | Benz(a)anthracene[b,c] | <1.8E-06 | E |
| 71-43-2 | Benzene[b] | 2.1E-03 | B |
| 50-32-8 | Benzo(a)pyrene[b,c] | <1.2E-06 | E |
| 205-99-2 | Benzo(b)fluoranthene[b,c] | <1.8E-06 | E |
| 191-24-2 | Benzo(g,h,i)perylene[b,c] | <1.2E-06 | E |
| 205-82-3 | Benzo(k)fluoranthene[b,c] | <1.8E-06 | E |
| 106-97-8 | Butane | 2.1E+00 | E |
| 218-01-9 | Chrysene[b,c] | <1.8E-06 | E |
| 53-70-3 | Dibenzo(a,h)anthracene[b,c] | <1.2E-06 | E |
| 25321-22-6 | Dichlorobenzene[b] | 1.2E-03 | E |
| 74-84-0 | Ethane | 3.1E+00 | E |
| 206-44-0 | Fluoranthene[b,c] | 3.0E-06 | E |
| 86-73-7 | Fluorene[b,c] | 2.8E-06 | E |
| 50-00-0 | Formaldehyde[b] | 7.5E-02 | B |
| 110-54-3 | Hexane[b] | 1.8E+00 | E |
| 193-39-5 | Indeno(1,2,3-cd)pyrene[b,c] | <1.8E-06 | E |
| 91-20-3 | Naphthalene[b] | 6.1E-04 | E |
| 109-66-0 | Pentane | 2.6E+00 | E |
| 85-01-8 | Phenanathrene[b,c] | 1.7E-05 | D |

TABLE 1.4-3. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM NATURAL GAS COMBUSTION (Continued)

| CAS No. | Pollutant | Emission Factor ($lb/10^6$ scf) | Emission Factor Rating |
|---|---|---|---|
| 74-98-6 | Propane | 1.6E+00 | E |
| 129-00-0 | Pyrene[b, c] | 5.0E-06 | E |
| 108-88-3 | Toluene[b] | 3.4E-03 | C |

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from $lb/10^6$ scf to $kg/10^6$ $m^3$, multiply by 16. To convert from $1b/10^6$ scf to lb/MMBtu, divide by 1,020. Emission Factors preceeded with a less-than symbol are based on method detection limits.

[b] Hazardous Air Pollutant (HAP) as defined by Section 112(b) of the Clean Air Act.

[c] HAP because it is Polycyclic Organic Matter (POM). POM is a HAP as defined by Section 112(b) of the Clean Air Act.

[d] The sum of individual organic compounds may exceed the VOC and TOC emission factors due to differences in test methods and the availability of test data for each pollutant.

TABLE 1.4-4. EMISSION FACTORS FOR METALS FROM NATURAL GAS COMBUSTION[a]

| CAS No. | Pollutant | Emission Factor ($lb/10^6$ scf) | Emission Factor Rating |
|---|---|---|---|
| 7440-38-2 | Arsenic[b] | 2.0E-04 | E |
| 7440-39-3 | Barium | 4.4E-03 | D |
| 7440-41-7 | Beryllium[b] | <1.2E-05 | E |
| 7440-43-9 | Cadmium[b] | 1.1E-03 | D |
| 7440-47-3 | Chromium[b] | 1.4E-03 | D |
| 7440-48-4 | Cobalt[b] | 8.4E-05 | D |
| 7440-50-8 | Copper | 8.5E-04 | C |
| 7439-96-5 | Manganese[b] | 3.8E-04 | D |
| 7439-97-6 | Mercury[b] | 2.6E-04 | D |
| 7439-98-7 | Molybdenum | 1.1E-03 | D |
| 7440-02-0 | Nickel[b] | 2.1E-03 | C |
| 7782-49-2 | Selenium[b] | <2.4E-05 | E |
| 7440-62-2 | Vanadium | 2.3E-03 | D |
| 7440-66-6 | Zinc | 2.9E-02 | E |

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. Emission factors preceeded by a less-than symbol are based on method detection limits. To convert from $lb/10^6$ scf to $kg/10^6$ $m^3$, multiply by 16. To convert from $lb/10^6$ scf to 1b/MMBtu, divide by 1,020.

[b] Hazardous Air Pollutant as defined by Section 112(b) of the Clean Air Act.

## 1.5 Liquefied Petroleum Gas Combustion

### 1.5.1 General[1]

Liquefied petroleum gas (LPG or LP-gas) consists of propane, propylene, butane, and butylenes; the product used for domestic heating is composed primarily of propane. This gas, obtained mostly from gas wells (but also, to a lesser extent, as a refinery by-product) is stored as a liquid under moderate pressures. There are three grades of LPG available as heating fuels: commercial-grade propane, engine fuel-grade propane (also known as HD-5 propane), and commercial-grade butane. In addition, there are high-purity grades of LPG available for laboratory work and for use as aerosol propellants. Specifications for the various LPG grades are available from the American Society for Testing and Materials and the Gas Processors Association. A typical heating value for commercial-grade propane and HD-5 propane is 90,500 British thermal units per gallon (Btu/gal), after vaporization; for commercial-grade butane, the value is 97,400 Btu/gal.

The largest market for LPG is the domestic/commercial market, followed by the chemical industry (where it is used as a petrochemical feedstock) and the agriculture industry. Propane is also used as an engine fuel as an alternative to gasoline and as a standby fuel for facilities that have interruptible natural gas service contracts.

### 1.5.2 Firing Practices[2]

The combustion processes that use LPG are very similar to those that use natural gas. Use of LPG in commercial and industrial applications may require a vaporizer to provide the burner with the proper mix of air and fuel. The burner itself will usually have different fuel injector tips as well as different fuel-to-air ratio controller settings than a natural gas burner since the LPG stoichiometric requirements are different than natural gas requirements. LPG is fired as a primary and backup fuel in small commercial and industrial boilers and space heating equipment and can be used to generate heat and process steam for industrial facilities and in most domestic appliances that typically use natural gas.

### 1.5.3 Emissions[1,3-5]

#### 1.5.3.1 Criteria Pollutants -

LPG is considered a "clean" fuel because it does not produce visible emissions. However, gaseous pollutants such as nitrogen oxides ($NO_x$), carbon monoxide (CO), and organic compounds are produced as are small amounts of sulfur dioxide ($SO_2$) and particulate matter (PM). The most significant factors affecting $NO_x$, CO, and organic emissions are burner design, burner adjustment, boiler operating parameters, and flue gas venting. Improper design, blocking and clogging of the flue vent, and insufficient combustion air result in improper combustion and the emission of aldehydes, CO, hydrocarbons, and other organics. $NO_x$ emissions are a function of a number of variables, including temperature, excess air, fuel and air mixing, and residence time in the combustion zone. The amount of $SO_2$ emitted is directly proportional to the amount of sulfur in the fuel. PM emissions are very low and result from soot, aerosols formed by condensable emitted species, or boiler scale dislodged during combustion. Emission factors for LPG combustion are presented in Table 1.5-1.

Table 1.5-1 presents emission factors on a volume basis (lb/$10^3$gal). To convert to an energy basis (lb/MMBtu), divide by a heating value of 91.5 MMBtu/$10^3$gal for propane and 102 MMBtu/$10^3$gal for butane.

#### 1.5.3.2 Greenhouse Gases[6-11] -

Carbon dioxide ($CO_2$), methane ($CH_4$), and nitrous oxide ($N_2O$) emissions are all produced during LPG combustion. Nearly all of the fuel carbon (99.5 percent) in LPG is converted to $CO_2$ during the combustion process. This conversion is relatively independent of firing configuration. Although the formation of CO acts to reduce $CO_2$ emissions, the amount of CO produced is insignificant compared to the amount of $CO_2$ produced. The majority of the 0.5 percent of fuel carbon not converted to $CO_2$ is due to incomplete combustion in the fuel stream.

## Table 1.5-1. EMISSION FACTORS FOR LPG COMBUSTION[a]

EMISSION FACTOR RATING: E

| Pollutant | Butane Emission Factor (lb/$10^3$ gal) | | Propane Emission Factor (lb/$10^3$ gal) | |
|---|---|---|---|---|
| | Industrial Boilers[b] (SCC 1-02-010-01) | Commercial Boilers[c] (SCC 1-03-010-01) | Industrial Boilers[b] (SCC 1-02-010-02) | Commercial Boilers[c] (SCC 1-03-010-02) |
| PM, Filterable [d] | 0.2 | 0.2 | 0.2 | 0.2 |
| PM, Condensable | 0.6 | 0.6 | 0.5 | 0.5 |
| PM, Total | 0.8 | 0.8 | 0.7 | 0.7 |
| $SO_2$[e] | 0.09S | 0.09S | 0.10S | 0.10S |
| $NO_x$[f] | 15 | 15 | 13 | 13 |
| $N_2O$[g] | 0.9 | 0.9 | 0.9 | 0.9 |
| $CO_2$[h,j] | 14,300 | 14,300 | 12,500 | 12,500 |
| CO | 8.4 | 8.4 | 7.5 | 7.5 |
| TOC | 1.1 | 1.1 | 1.0 | 1.0 |
| $CH_4$[k] | 0.2 | 0.2 | 0.2 | 0.2 |

[a] Assumes PM, CO, and TOC emissions are the same, on a heat input basis, as for natural gas combustion. Use heat contents of 91.5 x $10^6$ Btu/$10^3$ gallon for propane, 102 x $10^6$ Btu/$10^3$ gallon for butane, 1020 x $10^6$ Btu/$10^6$ scf for methane when calculating an equivalent heat input basis. For example, the equation for converting from methane's emissions factors to propane's emissions factors is as follows: lb pollutant/$10^3$ gallons of propane = (lb pollutant /$10^6$ ft$^3$ methane) * (91.5 x $10^6$ Btu/$10^3$ gallons of propane) / (1020 x $10^6$ Btu/$10^6$ scf of methane). The $NO_x$ emission factors have been multiplied by a correction factor of 1.5, which is the approximate ratio of propane/butane $NO_x$ emissions to natural gas $NO_x$ emissions. To convert from lb/$10^3$ gal to kg/$10^3$ L, multiply by 0.12. SCC = Source Classification Code.

[b] Heat input capacities generally between 10 and 100 million Btu/hour.

[c] Heat input capacities generally between 0.3 and 10 million Btu/hour.

[d] Filterable particulate matter (PM) is that PM collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train. For natural gas, a fuel with similar combustion characteristics, all PM is less than 10 μm in aerodynamic equivalent diameter (PM-10).

[e] S equals the sulfur content expressed in gr/100 ft$^3$ gas vapor. For example, if the butane sulfur content is 0.18 gr/100 ft$^3$, the emission factor would be (0.09 x 0.18) = 0.016 lb of $SO_2$/$10^3$ gal butane burned.

[f] Expressed as $NO_2$.

[g] Reference 12.

[h] Assuming 99.5% conversion of fuel carbon to $CO_2$.

[j] EMISSION FACTOR RATING = C.

[k] Reference 13.

## 1.6 Wood Residue Combustion In Boilers

### 1.6.1 General[1-6]

The burning of wood residue in boilers is mostly confined to those industries where it is available as a byproduct. It is burned both to obtain heat energy and to alleviate possible solid residue disposal problems. In boilers, wood residue is normally burned in the form of hogged wood, bark, sawdust, shavings, chips, mill rejects, sanderdust, or wood trim. Heating values for this residue range from about 4,500 British thermal units/pound (Btu/lb) of fuel on a wet, as-fired basis, to about 8,000 Btu/lb for dry wood. The moisture content of as-fired wood is typically near 50 weight percent for the pulp, paper and lumber industries and is typically 10 to 15 percent for the furniture industry. However, moisture contents may vary from 5 to 75 weight percent depending on the residue type and storage operations. Generally, bark is the major type of residue burned in pulp mills; either a mixture of wood and bark residue or wood residue alone is burned most frequently in the lumber, furniture, and plywood industries.

### 1.6.2 Firing Practices[5,7,8]

Various boiler firing configurations are used for burning wood residue. One common type of boiler used in smaller operations is the Dutch oven. This unit is widely used because it can burn fuels with very high moisture content. Fuel is fed into the oven through an opening in the top of a refractory-lined furnace. The fuel accumulates in a cone-shaped pile on a flat or sloping grate. Combustion is accomplished in two stages: (1) drying and gasification, and (2) combustion of gaseous products. The first stage takes place in the primary furnace, which is separated from the secondary furnace chamber by a bridge wall. Combustion is completed in the secondary chamber before gases enter the boiler section. The large mass of refractory helps to stabilize combustion rates but also causes a slow response to fluctuating steam demand.

In another boiler type, the fuel cell oven, fuel is dropped onto suspended fixed grates and is fired in a pile. Unlike the Dutch oven, the refractory-lined fuel cell also uses combustion air preheating and positioning of secondary and tertiary air injection ports to improve boiler efficiency. Because of their overall design and operating similarities, however, fuel cell and Dutch oven boilers have many comparable emission characteristics.

The firing method most commonly employed for wood-fired boilers with a steam generation rate larger than 100,000 lb/hr is the spreader stoker. In this boiler type, wood enters the furnace through a fuel chute and is spread either pneumatically or mechanically across the furnace, where small pieces of the fuel burn while in suspension. Simultaneously, larger pieces of fuel are spread in a thin, even bed on a stationary or moving grate. The burning is accomplished in three stages in a single chamber: (1) moisture evaporation; (2) distillation and burning of volatile matter; and (3) burning of fixed carbon. This type of boiler has a fast response to load changes, has improved combustion control, and can be operated with multiple fuels. Natural gas, oil, and/or coal, are often fired in spreader stoker boilers as auxiliary fuels. The fossil fuels are fired to maintain constant steam production when the wood residue moisture content or mass rate fluctuates and/or to provide more steam than can be generated from the residue supply alone. Although spreader stokers are the most common stokers among larger wood-fired boilers, overfeed and underfeed stokers are also utilized for smaller units.

Table 1.6-1. EMISSION FACTORS FOR PM FROM WOOD RESIDUE COMBUSTION[a]

| Fuel | PM Control Device | Filterable PM | | Filterable PM-10[b] | | Filterable PM-2.5[b] | |
|---|---|---|---|---|---|---|---|
| | | Emission Factor (lb/MMbtu) | EMISSION FACTOR RATING | Emission Factor (lb/MMbtu) | EMISSION FACTOR RATING | Emission Factor (lb/MMbtu) | EMISSION FACTOR RATING |
| Bark/Bark and Wet Wood | No Control[c] | 0.56[d] | C | 0.50[e] | D | 0.43[e] | D |
| Dry Wood | No Control[c] | 0.40[f] | A | 0.36[e] | D | 0.31[e] | D |
| Wet Wood | No Control[c] | 0.33[g] | A | 0.29[e] | D | 0.25[e] | D |
| Bark | Mechanical Collector | 0.54[h] | D | 0.49[e] | D | 0.29[e] | D |
| Bark and Wet Wood | Mechanical Collector | 0.35[i] | C | 0.32[e] | D | 0.19[e] | D |
| Dry Wood | Mechanical Collector | 0.30[j] | A | 0.27[e] | D | 0.16[e] | D |
| Wet Wood | Mechanical Collector | 0.22[k] | A | 0.20[e] | D | 0.12[e] | D |
| All Fuels[m] | Electrolyzed Gravel Bed | 0.1[m] | D | 0.074[e] | D | 0.065[e] | D |
| All Fuels[m] | Wet Scrubber | 0.066[n] | A | 0.065[e] | D | 0.065[e] | D |
| All Fuels[m] | Fabric Filter | 0.1[o] | C | 0.074[e] | D | 0.065[e] | |
| All Fuels[m] | Electrostatic Precipitator | 0.054[p] | B | 0.04[e] | D | 0.035[e] | |
| | | Condensible PM | | | | | |
| All Fuels[m] | All Controls/No Controls | 0.017[q] | A | | | | |

Table 1.6-1. (cont.)

[a] Units of lb of pollutant/million Btu (MMBtu) of heat input. To convert from lb/MMBtu to lb/ton, multiply by (HHV * 2000), where HHV is the higher heating value of the fuel, MMBtu/lb. CPM = Condensible Particulate Matter. These factors apply to Source Classification Codes (SCC) 1-0X-009-YY, where X = 1 for utilities, 2 for industrial, and 3 for commercial/institutional, and where Y = 01 for bark-fired boiler, 02 for bark and wet wood-fired boiler, 03 for wet wood-fired boiler, and 08 for dry wood-fired boiler.

[b] PM-10 = particulate matter less than or equal to 10 microns in aerodynamic diameter. PM-2.5 = particulate matter less than or equal to 2.5 microns in aerodynamic diameter. Filterable PM = PM captured and measured on the filter in an EPA Method 5 (or equivalent) sampling train. Condensible PM = PM captured and measured in an EPA Method 202 (or equivalent) sampling train.

[c] Factor represents boilers with no controls, Breslove separators, Breslove separators with reinjection, and mechanical collectors with reinjection. Mechanical collectors include cyclones and multiclones.

[d] References 19-21, 88.

[e] Cumulative mass % provided in Table 1.6-6 for Bark and Wet Wood-fired boilers multiplied by the Filterable PM factor.

[f] References 22-32, 88.

[g] References 26, 33-36, 88.

[h] References 37, 38, 88.

[i] References 26, 39-41, 88.

[j] References 26, 27, 34, 42-54, 88.

[k] Reference 55-57, 88.

[l] All fuels = Bark, Bark and Wet Wood, Dry Wood, and Wet Wood.

[m] References 27, 58, 88.

[n] References 26, 59-66, 88.

[o] References 26, 67-70, 88.

[p] References 26, 71-74, 88.

[q] References 19-21, 25, 28, 29, 31, 32, 36-41, 46, 51, 53-60, 62 - 65, 67-69, 72-75, 88.

Table 1.6-2. EMISSION FACTORS FOR $NO_x$, $SO_2$, AND CO FROM WOOD RESIDUE COMBUSTION[a]

| Source Category[c] | $NO_x$[b] | | $SO_2$[b] | | CO[b] | |
|---|---|---|---|---|---|---|
| | Emission Factor (lb/MMbtu) | EMISSION FACTOR RATING | Emission Factor (lb/MMBtu) | EMISSION FACTOR RATING | Emission Factor (lb/MMbtu) | EMISSION FACTOR RATING |
| Bark/bark and wet wood/wet wood-fired boiler | 0.22[d] | A | 0.025[e] | A | 0.60[f,g,i,j] | A |
| Dry wood-fired boilers | 0.49[h] | C | 0.025[e] | A | 0.60[f,g,i,j] | A |

[a] Units of lb of pollutant/million Btu (MMBtu) of heat input. To convert from lb/MMBtu to lb/ton, multiply by (HHV * 2000), where HHV is the higher heating value of the fuel, MMBtu/lb. To convert lb/MMBtu to kg/J, multiply by 4.3E-10. $NO_x$ = Nitrogen oxides, $SO_2$ = Sulfur dioxide, CO = Carbon monoxide.
[b] Factors represent boilers with no controls or with particulate matter controls.
[c] These factors apply to Source Classification Codes (SCC) 1-0X-009-YY, where X = 1 for utilities, 2 for industrial, and 3 for commercial/institutional, and where Y = 01 for bark-fired boiler, 02 for bark and wet wood-fired boiler, 03 for wet wood-fired boiler, and 08 for dry wood-fired boiler.
[d] References 19, 33, 34, 39. 40, 41, 55, 62-64, 67, 70, 72, 78, 79, 88-89.
[e] References 26, 45, 50, 72, 88-89.
[f] References 26, 59, 88-89.
[g] References 19, 26, 39-41, 60-64, 67, 68, 70, 75, 79, 88-89.
[h] References 30, 34, 45, 50, 80, 81, 88-89.
[i] References 26, 30, 45-51, 80-82, 88-89.
[j] Emission factor is for stokers and dutch ovens/fuel cells. References 26, 34, 36, 55, 60, 65, 71, 72, 75. **CO Factor for fluidized bed combustors is 0.17 lb/MMbtu.** References 26, 72, 88-89.

Table 1.6-3. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS, TOC, VOC, NITROUS OXIDE, AND CARBON DIOXIDE FROM WOOD RESIDUE COMBUSTION[a]

| Organic Compound | Average Emission Factor[b] (lb/MMBtu) | EMISSION FACTOR RATING |
|---|---|---|
| Acenaphthene | 9.1 E-07[c] | B |
| Acenaphthylene | 5.0 E-06[d] | A |
| Acetaldehyde | 8.3 E-04[e] | A |
| Acetone | 1.9 E-04[f] | D |
| Acetophenone | 3.2 E-09[g] | D |
| Acrolein | 4.0 E-03[h] | C |
| Anthracene | 3.0 E-06[i] | A |
| Benzaldehyde | <8.5 E-07[j] | D |
| Benzene | 4.2 E-03[k] | A |
| Benzo(a)anthracene | 6.5 E-08[l] | B |
| Benzo(a)pyrene | 2.6 E-06[m] | A |
| Benzo(b)fluoranthene | 1.0 E-07[f] | B |
| Benzo(e)pyrene | 2.6 E-09[f] | D |
| Benzo(g,h,i)perylene | 9.3 E-08[n] | B |
| Benzo(j,k)fluoranthene | 1.6 E-07[o] | D |
| Benzo(k)fluoranthene | 3.6 E-08[p] | B |
| Benzoic acid | 4.7 E-08[q] | D |
| bis(2-Ethylhexyl)phthalate | 4.7 E-08[g] | D |
| Bromomethane | 1.5 E-05[f] | D |
| 2-Butanone (MEK) | 5.4 E-06[f] | D |
| Carbazole | 1.8 E-06[f] | D |
| Carbon tetrachloride | 4.5 E-05[r] | D |
| Chlorine | 7.9 E-04[s] | D |
| Chlorobenzene | 3.3 E-05[f] | D |
| Chloroform | 2.8 E-05[f] | D |
| Chloromethane | 2.3 E-05[f] | D |
| 2-Chloronaphthalene | 2.4 E-09[f] | D |
| 2-Chlorophenol | 2.4 E-08[t] | C |
| Chrysene | 3.8 E-08[c] | B |
| Crotonaldehyde | 9.9 E-06[j] | D |
| Decachlorobiphenyl | 2.7 E-10[r] | D |
| Dibenzo(a,h)anthracene | 9.1 E-09[l] | B |
| 1,2-Dibromoethene | 5.5 E-05[f] | D |
| Dichlorobiphenyl | 7.4 E-10[r] | C |
| 1,2-Dichloroethane | 2.9 E-05[f] | D |
| Dichloromethane | 2.9 E-04[u] | D |
| 1,2-Dichloropropane | 3.3 E-05[f] | D |
| 2,4-Dinitrophenol | 1.8 E-07[v] | C |
| Ethylbenzene | 3.1 E-05[f] | D |
| Fluoranthene | 1.6 E-06[w] | B |
| Fluorene | 3.4 E-06[x] | A |
| Formaldehyde | 4.4 E-03[y] | A |
| Heptachlorobiphenyl | 6.6E-11[r] | D |

Table 1.6-3. (cont.)

| Organic Compound | Average Emission Factor[b] (lb/MMBtu) | EMISSION FACTOR RATING |
|---|---|---|
| Hexachlorobiphenyl | 5.5 E-10[r] | D |
| Hexanal | 7.0 E-06[e] | D |
| Heptachlorodibenzo-p-dioxins | 2.0 E-09[aa] | C |
| Heptachlorodibenzo-p-furans | 2.4 E-10[aa] | C |
| Hexachlorodibenzo-p-dioxins | 1.6 E-06[aa] | C |
| Hexachlorodibenzo-p-furans | 2.8 E-10[aa] | C |
| Hydrogen chloride | 1.9 E-02[j] | C |
| Indeno(1,2,3,c,d)pyrene | 8.7 E-08[l] | B |
| Isobutyraldehyde | 1.2 E-05[e] | D |
| Methane | 2.1 E-02[f] | C |
| 2-Methylnaphthalene | 1.6 E-07[e] | D |
| Monochlorobiphenyl | 2.2 E-10[r] | D |
| Naphthalene | 9.7 E-05[ab] | A |
| 2-Nitrophenol | 2.4 E-07[ac] | C |
| 4-Nitrophenol | 1.1 E-07[ac] | C |
| Octachlorodibenzo-p-dioxins | 6.6 E-08[aa] | B |
| Octachlorodibenzo-p-furans | 8.8 E-11[aa] | C |
| Pentachlorodibenzo-p-dioxins | 1.5 E-09[aa] | B |
| Pentachlorodibenzo-p-furans | 4.2 E-10[aa] | C |
| Pentachlorobiphenyl | 1.2 E-09[r] | D |
| Pentachlorophenol | 5.1 E-08[ac] | C |
| Perylene | 5.2 E-10[f] | D |
| Phenanthrene | 7.0 E-06[ad] | B |
| Phenol | 5.1 E-05[ac] | C |
| Propanal | 3.2 E-06[e] | D |
| Propionaldehyde | 6.1 E-05[f] | D |
| Pyrene | 3.7 E-06[af] | A |
| Styrene | 1.9 E-03[f] | D |
| 2,3,7,8-Tetrachlorodibenzo-p-dioxins | 8.6 E-12[aa] | C |
| Tetrachlorodibenzo-p-dioxins | 4.7 E-10[ag] | C |
| 2,3,7,8-Tetrachlorodibenzo-p-furans | 9.0 E-11[aa] | C |
| Tetrachlorodibenzo-p-furans | 7.5 E-10[aa] | C |
| Tetrachlorobiphenyl | 2.5 E-09[r] | D |
| Tetrachloroethene | 3.8 E-05[t] | D |
| o-Tolualdehyde | 7.2 E-06[j] | D |
| p-Tolualdehyde | 1.1 E-05[e] | D |
| Toluene | 9.2 E-04[v] | C |
| Trichlorobiphenyl | 2.6 E-09[r] | C |
| 1,1,1-Trichloroethane | 3.1 E-05[t] | D |
| Trichloroethene | 3.0 E-05[t] | D |
| Trichlorofluoromethane | 4.1 E-05 | D |
| 2,4,6-Trichlorophenol | <2.2 E-08[ak] | C |

Table 1.6-3. (cont.)

| Organic Compound | Average Emission Factor[b] (lb/MMBtu) | EMISSION FACTOR RATING |
|---|---|---|
| Vinyl Chloride | **1.8 E-05[r]** | D |
| o-Xylene | 2.5 E-05[t] | D |
| **Total organic compounds (TOC)** | **0.039[ai]** | D |
| Volatile organic compounds (VOC) | **0.017[aj]** | D |
| Nitrous Oxide ($N_2O$) | **0.013[ak]** | D |
| Carbon Dioxide ($CO_2$) | 195[al] | A |

[a] Units of lb of pollutant/million Btu (MMBtu) of heat input. To convert from lb/MMBtu to lb/ton, multiply by (HHV * 2000), where HHV is the higher heating value of the fuel, MMBtu/lb. To convert lb/MMBtu to kg/J, multiply by 4.3E-10. These factors apply to Source Classification Codes (SCC) 1-0X-009-YY, where X = 1 for utilities, 2 for industrial, and 3 for commercial/institutional, and where Y = 01 for bark-fired boiler, 02 for bark and wet wood-fired boiler, 03 for wet wood-fired boiler, and 08 for dry wood-fired boiler.

[b] Factors are for boilers with no controls or with particulate matter controls.

[c] References 26, 34, 36, 59, 60, 65, 71-73, 75.

[d] References 26, 33, 34, 36, 59, 60, 65, 71-73, 75.

[e] References, 26, 35, 36, 46, 50, 59, 60, 65, 71-75.

[f] Reference 26.

[g] Reference 33.

[h] Reference 26, 50, 83.

[i] References 26, 34, 36, 59, 60, 65, 71-73, 75.

[j] References 26, 50.

[k] References 26, 35, 36, 46, 59, 60, 65, 70, 71-75.

[l] References 26, 36, 59, 60, 65, 70-75.

[m] References 26, 33, 36, 59, 60, 65, 70-73, 75.

[n] References 26, 33, 36, 59, 60, 65, 71-73, 75.

[o] Reference 34.

[p] References 26, 36, 60, 65, 71-75.

[q] References 26, 33.

[r] References 26.

[s] Reference 83.

[t] References 26, 72.

[u] References 35, 60, 65, 71, 72.

[v] References 26, 72.

[w] References 35, 60, 65, 71, 72.

[x] References 26, 33, 34, 59, 60, 65, 71-75.

[y] References 26, 28, 35, 36, 46 - 51, 59, 60, 65, 70, 71-75, 79, 81, 82.

[z] Reference 50.

[aa] Reference 26, 45.

[ab] References 26, 33, 34, 36, 59, 60, 65, 71-75, 83.

[ac] References 26, 35, 60, 65, 71, 72.

[ad] References 26, 33, 34, 36, 59, 60, 65, 71 - 73.

[ae] References 26, 33, 34, 35, 60, 65, 70, 71, 72.

[af] References 26, 33, 34, 36, 59, 60, 65, 71 - 73, 83.

[ag] References 26, 45.

[ah] References 26, 35, 60, 65, 71.

[ai] TOC = total organic compounds. Factor is the sum of all factors in table except nitrous oxide and carbon dioxide.

[aj] VOC volatile organic compounds. Factor is the sum of all factors in table except hydrogen chloride, chlorine, formaldehyde, tetrachloroethene, 1,1,1,-trichloroethane, dichloromethane, acetone, nitrous oxide, methane, and carbon dioxide.

[ak] Reference 83.

[al] References 19 - 26, 33 - 49, 51- 57, 77, 79 - 82, 84 - 86.

Table 1.6-4. EMISSION FACTORS FOR TRACE ELEMENTS FROM WOOD RESIDUE COMBUSTION[a]

| Trace Element | Average Emission Factor (lb/MMBtu)[b] | EMISSION FACTOR RATING |
|---|---|---|
| Antimony | 7.9 E-06[c] | C |
| Arsenic | 2.2 E-05[d] | A |
| Barium | 1.7 E-04[c] | C |
| Beryllium | 1.1 E-06[e] | B |
| Cadmium | 4.1 E-06[f] | A |
| Chromium, total | 2.1 E-05[g] | A |
| Chromium, hexavalent | 3.5 E-06[h] | C |
| Cobalt | 6.5 E-06[i] | C |
| Copper | 4.9 E-05[j] | A |
| Iron | 9.9 E-04[k] | C |
| Lead | 4.8 E-05[l] | A |
| Manganese | 1.6 E-03[d] | A |
| Mercury | 3.5 E-06[m] | A |
| Molybdenum | 2.1 E-06[c] | D |
| Nickel | 3.3 E-05[n] | A |
| Phosphorus | 2.7 E-05[c] | D |
| Potassium | 3.9 E-02[c] | D |
| Selenium | 2.8 E-06[o] | A |
| Silver | 1.7 E-03[p] | D |
| Sodium | 3.6 E-04[c] | D |
| Strontium | 1.0 E-05[c] | D |
| Tin | 2.3 E-05[c] | D |
| Titanium | 2.0 E-05[c] | D |
| Vanadium | 9.8 E-07[c] | D |
| Yttrium | 3.0 E-07[c] | D |
| Zinc | 4.2 E-04[o] | A |

[a] Units of lb of pollutant/million Btu (MMBtu) of heat input. To convert from lb/MMBtu to lb/ton, multiply by (HHV * 2000), where HHV is the higher heating value of the fuel, MMBtu/lb. To convert lb/MMBtu to kg/J, multiply by 4.3E-10. These factors apply to Source Classification Codes (SCC) 1-0X-009-YY, where X = 1 for utilities, 2 for industrial, and 3 for commercial/institutional, and where Y = 01 for bark-fired boiler, 02 for bark and wet wood-fired boiler, 03 for wet wood-fired boiler, and 08 for dry wood-fired boiler.
[b] Factors are for boilers with no controls or with particulate matter controls.
[c] Reference 26.
[d] References 26, 33, 36, 46, 59, 60, 65, 71-73, 75, 81.
[e] References 26, 35, 36, 46, 59, 60, 65, 71-73, 75.
[f] References 26, 35, 36, 42, 46, 59, 60, 65, 71-73, 75, 81.
[g] References 26, 34, 35, 36, 42, 59, 60, 65, 71-73, 75, 81.
[h] References 26, 36, 46, 59, 60, 71, 72, 73, 75.
[i] References 26, 34, 83.
[j] References 26, 33-36, 46, 59, 60, 65, 71-73, 75, 81.
[k] References 26, 71, 72, 81.
[l] References 26, 33-36, 46, 59, 60, 65, 71-73, 75.
[m] References 26, 35, 36, 46, 59, 60, 65, 71-73, 75, 81.
[n] References 26, 33 - 36, 46, 59, 60, 65, 71-73, 75, 81.
[o] References 26, 33, 35, 46, 59, 60, 65, 71-73, 75, 81.
[p] Reference 34.

## 2.4 MUNICIPAL SOLID WASTE LANDFILLS

### 2.4.1 General[1-4]

A municipal solid waste (MSW) landfill unit is a discrete area of land or an excavation that receives household waste, and that is not a land application unit, surface impoundment, injection well, or waste pile. An MSW landfill unit may also receive other types of wastes, such as commercial solid waste, nonhazardous sludge, and industrial solid waste. The municipal solid waste types potentially accepted by MSW landfills include (most landfills accept only a few of the following categories):

- MSW,
- Household hazardous waste,
- Municipal sludge,
- Municipal waste combustion ash,
- Infectious waste,
- Waste tires,
- Industrial non-hazardous waste,
- Conditionally exempt small quantity generator (CESQG) hazardous waste,
- Construction and demolition waste,
- Agricultural wastes,
- Oil and gas wastes, and
- Mining wastes.

In the United States, approximately 57 percent of solid waste is landfilled, 16 percent is incinerated, and 27 percent is recycled or composted. There were an estimated 2,500 active MSW landfills in the United States in 1995. These landfills were estimated to receive 189 million megagrams (Mg) (208 million tons) of waste annually, with 55 to 60 percent reported as household waste, and 35 to 45 percent reported as commercial waste.

### 2.4.2 Process Description[2,5]

There are three major designs for municipal landfills. These are the area, trench, and ramp methods. All of these methods utilize a three step process, which includes spreading the waste, compacting the waste, and covering the waste with soil. The trench and ramp methods are not commonly used, and are not the preferred methods when liners and leachate collection systems are utilized or required by law. The area fill method involves placing waste on the ground surface or landfill liner, spreading it in layers, and compacting with heavy equipment. A daily soil cover is spread over the compacted waste. The trench method entails excavating trenches designed to receive a day's worth of waste. The soil from the excavation is often used for cover material and wind breaks. The ramp method is typically employed on sloping land, where waste is spread and compacted similar to the area method, however, the cover material obtained is generally from the front of the working face of the filling operation.

Modern landfill design often incorporates liners constructed of soil (i.e., recompacted clay), or synthetics (i.e., high density polyethylene), or both to provide an impermeable barrier to leachate (i.e., water that has passed through the landfill) and gas migration from the landfill.

Table 2.4-5. (English Units) EMISSION RATES FOR SECONDARY COMPOUNDS EXITING CONTROL DEVICES[a]

| Control Device | Pollutant[b] | $lb/10^6$ dscf Methane | Emission Factor Rating |
|---|---|---|---|
| Flare[c] (50100410) (50300601) | Nitrogen dioxide | 40 | C |
| | Carbon monoxide | 750 | C |
| | Particulate matter | 17 | D |
| IC Engine (50100421) | Nitrogen dioxide | 250 | D |
| | Carbon monoxide | 470 | C |
| | Particulate matter | 48 | E |
| Boiler/Steam Turbine[d] (50100423) | Nitrogen dioxide | 33 | E |
| | Carbon monoxide | 5.7 | E |
| | Particulate matter | 8.2 | E |
| Gas Turbine (50100420) | Nitrogen dioxide | 87 | D |
| | Carbon monoxide | 230 | D |
| | Particulate matter | 22 | E |

[a] Source Classification Codes in parentheses. Divide $lb/10^6$ dscf by 16,700 to obtain lb/hr/dscfm.
[b] Based on data for other combustion sources, most of the particulate matter will be less than 2.5 microns in diameter. Hence, this emission rate can be used to provide estimates of PM-10 or PM-2.5 emissions. See section 2.4.4.2 for methods to estimate $CO_2$, $SO_2$, and HCl.
[c] Where information on equipment was given in the reference, test data were taken from enclosed flares. Control efficiencies are assumed to be equally representative of open flares.
[d] All source tests were conducted on boilers, however emission factors should also be representative of steam turbines. Emission factors are representative of boilers equipped with low-$NO_x$ burners and flue gas recirculation. No data were available for uncontrolled $NO_x$ emissions.

References for Section 2.4


1. "Criteria for Municipal Solid Waste Landfills," 40 CFR Part 258, Volume 56, No. 196, October 9, 1991.

2. *Air Emissions from Municipal Solid Waste Landfills - Background Information for Proposed Standards and Guidelines*, Office of Air Quality Planning and Standards, EPA-450/3-90-011a, Chapters 3 and 4, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1991.

3. *Characterization of Municipal Solid Waste in the United States: 1992 Update*, Office of Solid Waste, EPA-530-R-92-019, U. S. Environmental Protection Agency, Washington, DC, NTIS No. PB92-207-166, July 1992.

4. Eastern Research Group, Inc., *List of Municipal Solid Waste Landfills*, Prepared for the U. S. Environmental Protection Agency, Office of Solid Waste, Municipal and Industrial Solid Waste Division, Washington, DC, September 1992.

5. *Suggested Control Measures for Landfill Gas Emissions*, State of California Air Resources Board, Stationary Source Division, Sacramento, CA, August 1990.

## 3.3 Gasoline And Diesel Industrial Engines

### 3.3.1 General

The engine category addressed by this section covers a wide variety of industrial applications of both gasoline and diesel internal combustion (IC) engines such as aerial lifts, fork lifts, mobile refrigeration units, generators, pumps, industrial sweepers/scrubbers, material handling equipment (such as conveyors), and portable well-drilling equipment. The three primary fuels for reciprocating IC engines are gasoline, diesel fuel oil (No.2), and natural gas. Gasoline is used primarily for mobile and portable engines. Diesel fuel oil is the most versatile fuel and is used in IC engines of all sizes. The rated power of these engines covers a rather substantial range, up to 250 horsepower (hp) for gasoline engines and up to 600 hp for diesel engines. (Diesel engines greater than 600 hp are covered in Section 3.4, "Large Stationary Diesel And All Stationary Dual-fuel Engines".) Understandably, substantial differences in engine duty cycles exist. It was necessary, therefore, to make reasonable assumptions concerning usage in order to formulate some of the emission factors.

### 3.3.2 Process Description

All reciprocating IC engines operate by the same basic process. A combustible mixture is first compressed in a small volume between the head of a piston and its surrounding cylinder. The mixture is then ignited, and the resulting high-pressure products of combustion push the piston through the cylinder. This movement is converted from linear to rotary motion by a crankshaft. The piston returns, pushing out exhaust gases, and the cycle is repeated.

There are 2 methods used for stationary reciprocating IC engines: compression ignition (CI) and spark ignition (SI). This section deals with both types of reciprocating IC engines. All diesel-fueled engines are compression ignited, and all gasoline-fueled engines are spark ignited.

In CI engines, combustion air is first compression heated in the cylinder, and diesel fuel oil is then injected into the hot air. Ignition is spontaneous because the air temperature is above the autoignition temperature of the fuel. SI engines initiate combustion by the spark of an electrical discharge. Usually the fuel is mixed with the air in a carburetor (for gasoline) or at the intake valve (for natural gas), but occasionally the fuel is injected into the compressed air in the cylinder.

CI engines usually operate at a higher compression ratio (ratio of cylinder volume when the piston is at the bottom of its stroke to the volume when it is at the top) than SI engines because fuel is not present during compression; hence there is no danger of premature autoignition. Since engine thermal efficiency rises with increasing pressure ratio (and pressure ratio varies directly with compression ratio), CI engines are more efficient than SI engines. This increased efficiency is gained at the expense of poorer response to load changes and a heavier structure to withstand the higher pressures.[1]

### 3.3.3 Emissions

Most of the pollutants from IC engines are emitted through the exhaust. However, some total organic compounds (TOC) escape from the crankcase as a result of blowby (gases that are vented from the oil pan after they have escaped from the cylinder past the piston rings) and from the fuel tank and carburetor because of evaporation. Nearly all of the TOCs from diesel CI engines enter the

Table 3.3-2. SPECIATED ORGANIC COMPOUND EMISSION FACTORS FOR UNCONTROLLED DIESEL ENGINES[a]

EMISSION FACTOR RATING: E

| Pollutant | Emission Factor (Fuel Input) (lb/MMBtu) |
|---|---|
| Benzene[b] | 9.33 E-04 |
| Toluene[b] | 4.09 E-04 |
| Xylenes[b] | 2.85 E-04 |
| Propylene | 2.58 E-03 |
| 1,3-Butadiene[b,c] | <3.91 E-05 |
| Formaldehyde[b] | 1.18 E-03 |
| Acetaldehyde[b] | 7.67 E-04 |
| Acrolein[b] | <9.25 E-05 |
| Polycyclic aromatic hydrocarbons (PAH) | |
| Naphthalene[b] | 8.48 E-05 |
| Acenaphthylene | <5.06 E-06 |
| Acenaphthene | <1.42 E-06 |
| Fluorene | 2.92 E-05 |
| Phenanthrene | 2.94 E-05 |
| Anthracene | 1.87 E-06 |
| Fluoranthene | 7.61 E-06 |
| Pyrene | 4.78 E-06 |
| Benzo(a)anthracene | 1.68 E-06 |
| Chrysene | 3.53 E-07 |
| Benzo(b)fluoranthene | <9.91 E-08 |
| Benzo(k)fluoranthene | <1.55 E-07 |
| Benzo(a)pyrene | <1.88 E-07 |
| Indeno(1,2,3-cd)pyrene | <3.75 E-07 |
| Dibenz(a,h)anthracene | <5.83 E-07 |
| Benzo(g,h,l)perylene | <4.89 E-07 |
| TOTAL PAH | 1.68 E-04 |

[a] Based on the uncontrolled levels of 2 diesel engines from References 6-7. Source Classification Codes 2-02-001-02, 2-03-001-01. To convert from lb/MMBtu to ng/J, multiply by 430.
[b] Hazardous air pollutant listed in the *Clean Air Act*.
[c] Based on data from 1 engine.

## 3.4 Large Stationary Diesel And All Stationary Dual-fuel Engines

### 3.4.1 General

The primary domestic use of large stationary diesel engines (greater than 600 horsepower [hp]) is in oil and gas exploration and production. These engines, in groups of 3 to 5, supply mechanical power to operate drilling (rotary table), mud pumping, and hoisting equipment, and may also operate pumps or auxiliary power generators. Another frequent application of large stationary diesels is electricity generation for both base and standby service. Smaller uses include irrigation, hoisting, and nuclear power plant emergency cooling water pump operation.

Dual-fuel engines were developed to obtain compression ignition performance and the economy of natural gas, using a minimum of 5 to 6 percent diesel fuel to ignite the natural gas. Large dual-fuel engines have been used almost exclusively for prime electric power generation. This section includes all dual-fuel engines.

### 3.4.2 Process Description

All reciprocating internal combustion (IC) engines operate by the same basic process. A combustible mixture is first compressed in a small volume between the head of a piston and its surrounding cylinder. The mixture is then ignited, and the resulting high-pressure products of combustion push the piston through the cylinder. This movement is converted from linear to rotary motion by a crankshaft. The piston returns, pushing out exhaust gases, and the cycle is repeated.

There are 2 ignition methods used in stationary reciprocating IC engines, compression ignition (CI) and spark ignition (SI). In CI engines, combustion air is first compression heated in the cylinder, and diesel fuel oil is then injected into the hot air. Ignition is spontaneous because the air temperature is above the autoignition temperature of the fuel. SI engines initiate combustion by the spark of an electrical discharge. Usually the fuel is mixed with the air in a carburetor (for gasoline) or at the intake valve (for natural gas), but occasionally the fuel is injected into the compressed air in the cylinder. Although all diesel- fueled engines are compression ignited and all gasoline- and gas-fueled engines are spark ignited, gas can be used in a CI engine if a small amount of diesel fuel is injected into the compressed gas/air mixture to burn any mixture ratio of gas and diesel oil (hence the name dual fuel), from 6 to 100 percent diesel oil.

CI engines usually operate at a higher compression ratio (ratio of cylinder volume when the piston is at the bottom of its stroke to the volume when it is at the top) than SI engines because fuel is not present during compression; hence there is no danger of premature autoignition. Since engine thermal efficiency rises with increasing pressure ratio (and pressure ratio varies directly with compression ratio), CI engines are more efficient than SI engines. This increased efficiency is gained at the expense of poorer response to load changes and a heavier structure to withstand the higher pressures.[1]

### 3.4.3 Emissions And Controls

Most of the pollutants from IC engines are emitted through the exhaust. However, some total organic compounds (TOC) escape from the crankcase as a result of blowby (gases that are vented from the oil pan after they have escaped from the cylinder past the piston rings) and from the fuel tank

Table 3.4-3. SPECIATED ORGANIC COMPOUND EMISSION FACTORS FOR LARGE UNCONTROLLED STATIONARY DIESEL ENGINES[a]

EMISSION FACTOR RATING: E

| Pollutant | Emission Factor (lb/MMBtu) (fuel input) |
|---|---|
| Benzene[b] | 7.76 E-04 |
| Toluene[b] | 2.81 E-04 |
| Xylenes[b] | 1.93 E-04 |
| Propylene | 2.79 E-03 |
| Formaldehyde[b] | 7.89 E-05 |
| Acetaldehyde[b] | 2.52 E-05 |
| Acrolein[b] | 7.88 E-06 |

[a]Based on 1 uncontrolled diesel engine from Reference 7. Source Classification Code 2-02-004-01. Not enough information to calculate the output-specific emission factors of lb/hp-hr. To convert from lb/MMBtu to ng/J, multiply by 430.
[b]Hazardous air pollutant listed in the *Clean Air Act*.

Table 3.4-4. PAH EMISSION FACTORS FOR LARGE UNCONTROLLED STATIONARY DIESEL ENGINES[a]

EMISSION FACTOR RATING: E

| PAH | Emission Factor (lb/MMBtu) (fuel input) |
|---|---|
| Naphthalene[b] | 1.30 E-04 |
| Acenaphthylene | 9.23 E-06 |
| Acenaphthene | 4.68 E-06 |
| Fluorene | 1.28 E-05 |
| Phenanthrene | 4.08 E-05 |
| Anthracene | 1.23 E-06 |
| Fluoranthene | 4.03 E-06 |
| Pyrene | 3.71 E-06 |
| Benz(a)anthracene | 6.22 E-07 |
| Chrysene | 1.53 E-06 |
| Benzo(b)fluoranthene | 1.11 E-06 |
| Benzo(k)fluoranthene | <2.18 E-07 |
| Benzo(a)pyrene | <2.57 E-07 |
| Indeno(1,2,3-cd)pyrene | <4.14 E-07 |
| Dibenz(a,h)anthracene | <3.46 E-07 |
| Benzo(g,h,l)perylene | <5.56 E-07 |
| TOTAL PAH | <2.12 E-04 |

[a] Based on 1 uncontrolled diesel engine from Reference 7. Source Classification Code 2-02-004-01. Not enough information to calculate the output-specific emission factors of lb/hp-hr. To convert from lb/MMBtu to ng/J, multiply by 430.

[b] Hazardous air pollutant listed in the *Clean Air Act*.

## 11.9 Western Surface Coal Mining

### 11.9.1 General[1]

There are 12 major coal fields in the western states (excluding the Pacific Coast and Alaskan fields), as shown in Figure 11.9-1. Together, they account for more than 64 percent of the surface minable coal reserves in the United States.[2] The 12 coal fields have varying characteristics that may influence fugitive dust emission rates from mining operations including overburden and coal seam thicknesses and structure, mining equipment, operating procedures, terrain, vegetation, precipitation and surface moisture, wind speeds, and temperatures. The operations at a typical western surface mine are shown in Figure 11.9-2. All operations that involve movement of soil or coal, or exposure of erodible surfaces, generate some amount of fugitive dust.

The initial operation is removal of topsoil and subsoil with large scrapers. The topsoil is carried by the scrapers to cover a previously mined and regraded area as part of the reclamation process or is placed in temporary stockpiles. The exposed overburden, the earth that is between the topsoil and the coal seam, is leveled, drilled, and blasted. Then the overburden material is removed down to the coal seam, usually by a dragline or a shovel and truck operation. It is placed in the adjacent mined cut, forming a spoils pile. The uncovered coal seam is then drilled and blasted. A shovel or front end loader loads the broken coal into haul trucks, and it is taken out of the pit along graded haul roads to the tipple, or truck dump. Raw coal sometimes may be dumped onto a temporary storage pile and later rehandled by a front end loader or bulldozer.

At the tipple, the coal is dumped into a hopper that feeds the primary crusher, then is conveyed through additional coal preparation equipment such as secondary crushers and screens to the storage area. If the mine has open storage piles, the crushed coal passes through a coal stacker onto the pile. The piles, usually worked by bulldozers, are subject to wind erosion. From the storage area, the coal is conveyed to a train loading facility and is put into rail cars. At a captive mine, coal will go from the storage pile to the power plant.

During mine reclamation, which proceeds continuously throughout the life of the mine, overburden spoils piles are smoothed and contoured by bulldozers. Topsoil is placed on the graded spoils, and the land is prepared for revegetation by furrowing, mulching, etc. From the time an area is disturbed until the new vegetation emerges, all disturbed areas are subject to wind erosion.

### 11.9.2 Emissions

Predictive emission factor equations for open dust sources at western surface coal mines are presented in Tables 11.9-1 and 11.9-2. Each equation applies to a single dust-generating activity, such as vehicle traffic on haul roads. The predictive equation explains much of the observed variance in emission factors by relating emissions to three sets of source parameters: (1) measures of source activity or energy expended (e. g., speed and weight of a vehicle traveling on an unpaved road); (2) properties of the material being disturbed (e. g., suspendable fines in the surface material of an unpaved road); and (3) climate (in this case, mean wind speed).

Table 11.9-1 (English Units). EMISSION FACTOR EQUATIONS FOR UNCONTROLLED OPEN DUST SOURCES AT WESTERN SURFACE COAL MINES[a]

| Operation | Material | Emissions By Particle Size Range (Aerodynamic Diameter)[b,c] | | | | Units | EMISSION FACTOR RATING |
|---|---|---|---|---|---|---|---|
| | | Emission Factor Equations | | Scaling Factors | | | |
| | | TSP ≤30 µm | ≤15 µm | ≤10 µm[d] | ≤2.5 µm/TSP[e] | | |
| Blasting[f] | Coal or overburden | $0.000014(A)^{1.5}$ | ND | 0.52[e] | 0.03 | lb/blast | C_DD |
| Truck loading | Coal | $\frac{1.16}{(M)^{1.2}}$ | $\frac{0.119}{(M)^{0.9}}$ | 0.75 | 0.019 | lb/ton | BBCC |
| Bulldozing | Coal | $\frac{78.4\ (s)^{1.2}}{(M)^{1.3}}$ | $\frac{18.6\ (s)^{1.5}}{(M)^{1.4}}$ | 0.75 | 0.022 | lb/hr | CCDD |
| | Overburden | $\frac{5.7\ (s)^{1.2}}{(M)^{1.3}}$ | $\frac{1.0\ (s)^{1.5}}{(M)^{1.4}}$ | 0.75 | 0.105 | lb/hr | BCDD |
| Dragline | Overburden | $\frac{0.0021\ (d)^{1.1}}{(M)^{0.3}}$ | $\frac{0.0021\ (d)^{0.7}}{(M)^{0.3}}$ | 0.75 | 0.017 | lb/yd³ | BCDD |
| Vehicle traffic[g] | | | | | | | |
| Grading | | $0.040\ (S)^{2.5}$ | $0.051\ (S)^{2.0}$ | 0.60 | 0.031 | lb/VMT | CCDD |
| Active storage pile[h] (wind erosion and maintenance) | Coal | 0.72 u | ND | ND | ND | $\frac{lb}{(acre)(hr)}$ | C[i]___ |

[a] Reference 1, except as noted. VMT = vehicle miles traveled. ND = no data. Quality ratings coded where "Q, X, Y, Z" are ratings for ≤30 µm, ≤15 µm, ≤10 µm, and ≤2.5 µm, respectively. See also note below.

[b] Particulate matter less than or equal to 30 µm in aerodynamic diameter is sometimes termed "suspendable particulate" and is often used as a surrogate for TSP (total suspended particulate). TSP denotes what is measured by a standard high volume sampler (see Section 13.2).

[c] Symbols for equations:

- A = horizontal area (ft²), with blasting depth ≤ 70 ft. Not for vertical face of a bench.
- M = material moisture content (%)
- s = material silt content (%)
- u = wind speed (mph)
- d = drop height (ft)
- W = mean vehicle weight (tons)
- S = mean vehicle speed (mph)
- w = mean number of wheels

## 11.19.2 Crushed Stone Processing and Pulverized Mineral Processing

11.19.2.1 Process Description [24,25]

### Crushed Stone Processing

Major rock types processed by the crushed stone industry include limestone, granite, dolomite, traprock, sandstone, quartz, and quartzite. Minor types include calcareous marl, marble, shell, and slate. Major mineral types processed by the pulverized minerals industry, a subset of the crushed stone processing industry, include calcium carbonate, talc, and barite. Industry classifications vary considerably and, in many cases, do not reflect actual geological definitions.

Rock and crushed stone products generally are loosened by drilling and blasting and then are loaded by power shovel or front-end loader into large haul trucks that transport the material to the processing operations. Techniques used for extraction vary with the nature and location of the deposit. Processing operations may include crushing, screening, size classification, material handling and storage operations. All of these processes can be significant sources of PM and PM-10 emissions if uncontrolled.

Quarried stone normally is delivered to the processing plant by truck and is dumped into a bin. A feeder is used as illustrated in Figure 11.19.2-1. The feeder or screens separate large boulders from finer rocks that do not require primary crushing, thus reducing the load to the primary crusher. Jaw, impactor, or gyratory crushers are usually used for initial reduction. The crusher product, normally 7.5 to 30 centimeters (3 to 12 inches) in diameter, and the grizzly throughs (undersize material) are discharged onto a belt conveyor and usually are conveyed to a surge pile for temporary storage or are sold as coarse aggregates.

The stone from the surge pile is conveyed to a vibrating inclined screen called the scalping screen. This unit separates oversized rock from the smaller stone. The undersized material from the scalping screen is considered to be a product stream and is transported to a storage pile and sold as base material. The stone that is too large to pass through the top deck of the scalping screen is processed in the secondary crusher. Cone crushers are commonly used for secondary crushing (although impact crushers are sometimes used), which typically reduces material to about 2.5 to 10 centimeters (1 to 4 inches). The material (throughs) from the second level of the screen bypasses the secondary crusher because it is sufficiently small for the last crushing step. The output from the secondary crusher and the throughs from the secondary screen are transported by conveyor to the tertiary circuit, which includes a sizing screen and a tertiary crusher.

Tertiary crushing is usually performed using cone crushers or other types of impactor crushers. Oversize material from the top deck of the sizing screen is fed to the tertiary crusher. The tertiary crusher output, which is typically about 0.50 to 2.5 centimeters (3/16th to 1 inch), is returned to the sizing screen. Various product streams with different size gradations are separated in the screening operation. The products are conveyed or trucked directly to finished product bins, to open area stock piles, or to other processing systems such as washing, air separators, and screens and classifiers (for the production of manufactured sand).

Some stone crushing plants produce manufactured sand. This is a small-sized rock product with a maximum size of 0.50 centimeters (3/16 th inch). Crushed stone from the tertiary sizing screen is sized in a vibrating inclined screen (fines screen) with relatively small mesh sizes.

## Table 11.19.2-1 (Metric Units). EMISSION FACTORS FOR CRUSHED STONE PROCESSING OPERATIONS (kg/Mg)[a]

| Source[b] | Total Particulate Matter[r,s] | EMISSION FACTOR RATING | Total PM-10 | EMISSION FACTOR RATING | Total PM-2.5 | EMISSION FACTOR RATING |
|---|---|---|---|---|---|---|
| Primary Crushing (SCC 3-05-020-01) | ND | | ND[n] | | ND[n] | |
| Primary Crushing (controlled) (SCC 3-05-020-01) | ND | | ND[n] | | ND[n] | |
| Secondary Crushing (SCC 3-05-020-02) | ND | | ND[n] | | ND[n] | |
| Secondary Crushing (controlled) (SCC 3-05-020-02) | ND | | ND[n] | | ND[n] | |
| Tertiary Crushing (SCC 3-050030-03) | 0.0027[d] | E | 0.0012[o] | C | ND[n] | |
| Tertiary Crushing (controlled) (SCC 3-05-020-03) | 0.0006[d] | E | 0.00027[p] | C | 0.00005[q] | E |
| Fines Crushing (SCC 3-05-020-05) | 0.0195[e] | E | 0.0075[e] | E | ND | |
| Fines Crushing (controlled) (SCC 3-05-020-05) | 0.0015[f] | E | 0.0006[f] | E | 0.000035[q] | E |
| Screening (SCC 3-05-020-02, 03) | 0.0125[c] | E | 0.0043[l] | C | ND | |
| Screening (controlled) (SCC 3-05-020-02, 03) | 0.0011[d] | E | 0.00037[m] | C | 0.000025[q] | E |
| Fines Screening (SCC 3-05-020-21 | 0.15[g] | E | 0.036[g] | E | ND | |
| Fines Screening (controlled) (SCC 3-05-020-21) | 0.0018[g] | E | 0.0011[g] | E | ND | |
| Conveyor Transfer Point (SCC 3-05-020-06) | 0.0015[h] | E | 0.00055[h] | D | ND | |
| Conveyor Transfer Point (controlled) (SCC 3-05-020-06) | 0.00007[i] | E | $2.3 \times 10^{-5}$[i] | D | $6.5 \times 10^{-6}$[q] | E |
| Wet Drilling - Unfragmented Stone (SCC 3-05-020-10) | ND | | $4.0 \times 10^{-5}$[j] | E | ND | |
| Truck Unloading - Fragmented Stone (SCC 3-05-020-31) | ND | | $8.0 \times 10^{-6}$[j] | E | ND | |
| Truck Unloading - Conveyor, crushed stone (SCC 3-05-020-32) | ND | | $5.0 \times 10^{-5}$[k] | E | ND | |

a. Emission factors represent uncontrolled emissions unless noted. Emission factors in kg/Mg of material throughput. *SCC = Source Classification Code. ND = No data.*

b. Controlled sources (with wet suppression) are those that are part of the processing plant that employs current wet suppression technology similar to the study group. The moisture content of the study group without wet suppression systems operating (uncontrolled) ranged from 0.21 to 1.3 percent, and the same facilities operating wet suppression systems (controlled) ranged from 0.55 to 2.88 percent. Due to carry over of the small amount of moisture required, it has been shown that each source, with the exception of crushers, does not need to employ direct water sprays. Although the moisture content was the only variable measured, other process features may have as much influence on emissions from a given source. Visual observations from each source under normal operating conditions are probably the best indicator of which emission factor is most appropriate. Plants that employ substandard control measures as indicated by visual observations should use the uncontrolled factor with appropriate control efficiency that best reflects the effectiveness of the controls employed.

c. References 1, 3, 7, and 8

d. References 3, 7, and 8

e. Reference 4

f. References 4 and 15

g. Reference 4

h. References 5 and 6

i. References 5, 6, and 15

j. Reference 11

k. Reference 12

l. References 1, 3, 7, and 8

m. References 1, 3, 7, 8, and 15

n. No data available, but emission factors for PM-10 for tertiary crushers can be used as an upper limit for primary or secondary crushing

o. References 2, 3, 7, 8

p. References 2, 3, 7, 8, and 15

q. Reference 15

r. PM emission factors are presented based on PM-100 data in the Background Support Document for Section 11.19.2

s. Emission factors for PM-30 and PM-50 are available in Figures 11.19.2-3 through 11.19.2-6.

Table 11.19.2-2 (English Units). EMISSION FACTORS FOR CRUSHED STONE PROCESSING OPERATIONS (lb/Ton)[a]

| Source[b] | Total Particulate Matter[r,s] | EMISSION FACTOR RATING | Total PM-10 | EMISSION FACTOR RATING | Total PM-2.5 | EMISSION FACTOR RATING |
|---|---|---|---|---|---|---|
| Primary Crushing (SCC 3-05-020-01) | ND | | ND[n] | | ND[n] | |
| Primary Crushing (controlled) (SCC 3-05-020-01) | ND | | ND[n] | | ND[n] | |
| Secondary Crushing (SCC 3-05-020-02) | ND | | ND[n] | | ND[n] | |
| Secondary Crushing (controlled) (SCC 3-05-020-02) | ND | | ND[n] | | ND[n] | |
| Tertiary Crushing (SCC 3-050030-03) | 0.0054[d] | E | 0.0024[o] | C | ND[n] | |
| Tertiary Crushing (controlled) (SCC 3-05-020-03) | 0.0012[d] | E | 0.00054[p] | C | 0.00010[q] | E |
| Fines Crushing (SCC 3-05-020-05) | 0.0390[e] | E | 0.0150[e] | E | ND | |
| Fines Crushing (controlled) (SCC 3-05-020-05) | 0.0030[f] | E | 0.0012[f] | E | 0.000070[q] | E |
| Screening (SCC 3-05-020-02, 03) | 0.025[c] | E | 0.0087[l] | C | ND | |
| Screening (controlled) (SCC 3-05-020-02, 03) | 0.0022[d] | E | 0.00074[m] | C | 0.000050[q] | E |
| Fines Screening (SCC 3-05-020-21) | 0.30[g] | E | 0.072[g] | E | ND | |
| Fines Screening (controlled) (SCC 3-05-020-21) | 0.0036[g] | E | 0.0022[g] | E | ND | |
| Conveyor Transfer Point (SCC 3-05-020-06) | 0.0030[h] | E | 0.00110[h] | D | ND | |
| Conveyor Transfer Point (controlled) (SCC 3-05-020-06) | 0.00014[i] | E | $4.6 \times 10^{-5}$[i] | D | $1.3 \times 10^{-5}$[q] | E |
| Wet Drilling - Unfragmented Stone (SCC 3-05-020-10) | ND | | $8.0 \times 10^{-5}$[j] | E | ND | |
| Truck Unloading -Fragmented Stone (SCC 3-05-020-31) | ND | | $1.6 \times 10^{-5}$[j] | E | ND | |
| Truck Unloading - Conveyor, crushed stone (SCC 3-05-020-32) | ND | | 0.00010[k] | E | ND | |

a. Emission factors represent uncontrolled emissions unless noted. Emission factors in lb/Ton of material of throughput. SCC = Source Classification Code. ND = No data.

b. Controlled sources (with wet suppression) are those that are part of the processing plant that employs current wet suppression technology similar to the study group. The moisture content of the study group without wet suppression systems operating (uncontrolled) ranged from 0.21 to 1.3 percent, and the same facilities operating wet suppression systems (controlled) ranged from 0.55 to 2.88 percent. Due to carry over of the small amount of moisture required, it has been shown that each source, with the exception of crushers, does not need to employ direct water sprays. Although the moisture content was the only variable measured, other process features may have as much influence on emissions from a given source. Visual observations from each source under normal operating conditions are probably the best indicator of which emission factor is most appropriate. Plants that employ substandard control measures as indicated by visual observations should use the uncontrolled factor with an appropriate control efficiency that best reflects the effectiveness of the controls employed.

c. References 1, 3, 7, and 8

d. References 3, 7, and 8

e. Reference 4

f. References 4 and 15

g. Reference 4

h. References 5 and 6

i. References 5, 6, and 15

j. Reference 11

k. Reference 12

l. References 1, 3, 7, and 8

m. References 1, 3, 7, 8, and 15

n. No data available, but emission factors for PM-10 for tertiary crushers can be used as an upper limit for primary or secondary crushing

o. References 2, 3, 7, 8

p. References 2, 3, 7, 8, and 15

q. Reference 15

r. PM emission factors are presented based on PM-100 data in the Background Support Document for Section 11.19.2

s. Emission factors for PM-30 and PM-50 are available in Figures 11.19.2-3 through 11.19.2-6.

## 13.2.1 Paved Roads

### 13.2.1.1 General

Particulate emissions occur whenever vehicles travel over a paved surface such as a road or parking lot. Particulate emissions from paved roads are due to direct emissions from vehicles in the form of exhaust, brake wear and tire wear emissions and resuspension of loose material on the road surface. In general terms, resuspended particulate emissions from paved roads originate from, and result in the depletion of, the loose material present on the surface (i.e., the surface loading). In turn, that surface loading is continuously replenished by other sources. At industrial sites, surface loading is replenished by spillage of material and trackout from unpaved roads and staging areas. Figure 13.2.1-1 illustrates several transfer processes occurring on public streets.

Various field studies have found that public streets and highways, as well as roadways at industrial facilities, can be major sources of the atmospheric particulate matter within an area.[1-9] Of particular interest in many parts of the United States are the increased levels of emissions from public paved roads when the equilibrium between deposition and removal processes is upset. This situation can occur for various reasons, including application of granular materials for snow and ice control, mud/dirt carryout from construction activities in the area, and deposition from wind and/or water erosion of surrounding unstabilized areas. In the absence of continuous addition of fresh material (through localized track out or application of antiskid material), paved road surface loading should reach an equilibrium value in which the amount of material resuspended matches the amount replenished. The equilibrium surface loading value depends upon numerous factors. It is believed that the most important factors are: mean speed of vehicles traveling the road; the average daily traffic (ADT); the number of lanes and ADT per lane; the fraction of heavy vehicles (buses and trucks); and the presence/absence of curbs, storm sewers and parking lanes.[10]

The particulate emission factors presented in a previous version of this section of AP-42, dated October 2002, implicitly included the emissions from vehicles in the form of exhaust, brake wear, and tire wear as well as resuspended road surface material. EPA included these sources in the emission factor equation for paved roads since the field testing data used to develop the equation included both the direct emissions from vehicles and emissions from resuspension of road dust.

This version of the paved road emission factor equation only estimates particulate emissions from resuspended road surface material[28]. The particulate emissions from vehicle exhaust, brake wear, and tire wear are now estimated separately using EPA's MOVES [29] model. This approach eliminates the possibility of double counting emissions. Double counting results when employing the previous version of the emission factor equation in this section and MOVES to estimate particulate emissions from vehicle traffic on paved roads. It also incorporates the decrease in exhaust emissions that has occurred since the paved road emission factor equation was developed. Earlier versions of the paved road emission factor equation includes estimates of emissions from exhaust, brake wear, and tire wear based on emission rates for vehicles in the 1980 calendar year fleet. The amount of PM released from vehicle exhaust has decreased since 1980 due to lower new vehicle emission standards and changes in fuel characteristics.

13.2.1.2 Emissions And Correction Parameters

Dust emissions from paved roads have been found to vary with what is termed the "silt loading" present on the road surface. In addition, the average weight and speed of vehicles traveling the road influence road dust emissions. The term silt loading (sL) refers to the mass of silt-size material (equal to or less than 75 micrometers [μm] in physical diameter) per unit area of the travel surface. The total road surface dust loading consists of loose material that can be collected by broom sweeping and vacuuming of the traveled portion of the paved road. The silt fraction is determined by measuring the proportion of the loose dry surface dust that passes through a 200-mesh screen, using the ASTM-C-136 method. Silt loading is the product of the silt fraction and the total loading, and is abbreviated "sL". Additional details on the sampling and analysis of such material are provided in AP-42 Appendices C.1 and C.2.

The surface sL provides a reasonable means of characterizing seasonal variability in a paved road emission inventory. In many areas of the country, road surface loadings [11-21] are heaviest during the late winter and early spring months when the residual loading from snow/ice controls is greatest. As noted earlier, once replenishment of fresh material is eliminated, the road surface loading can be expected to reach an equilibrium value, which is substantially lower than the late winter/early spring values.

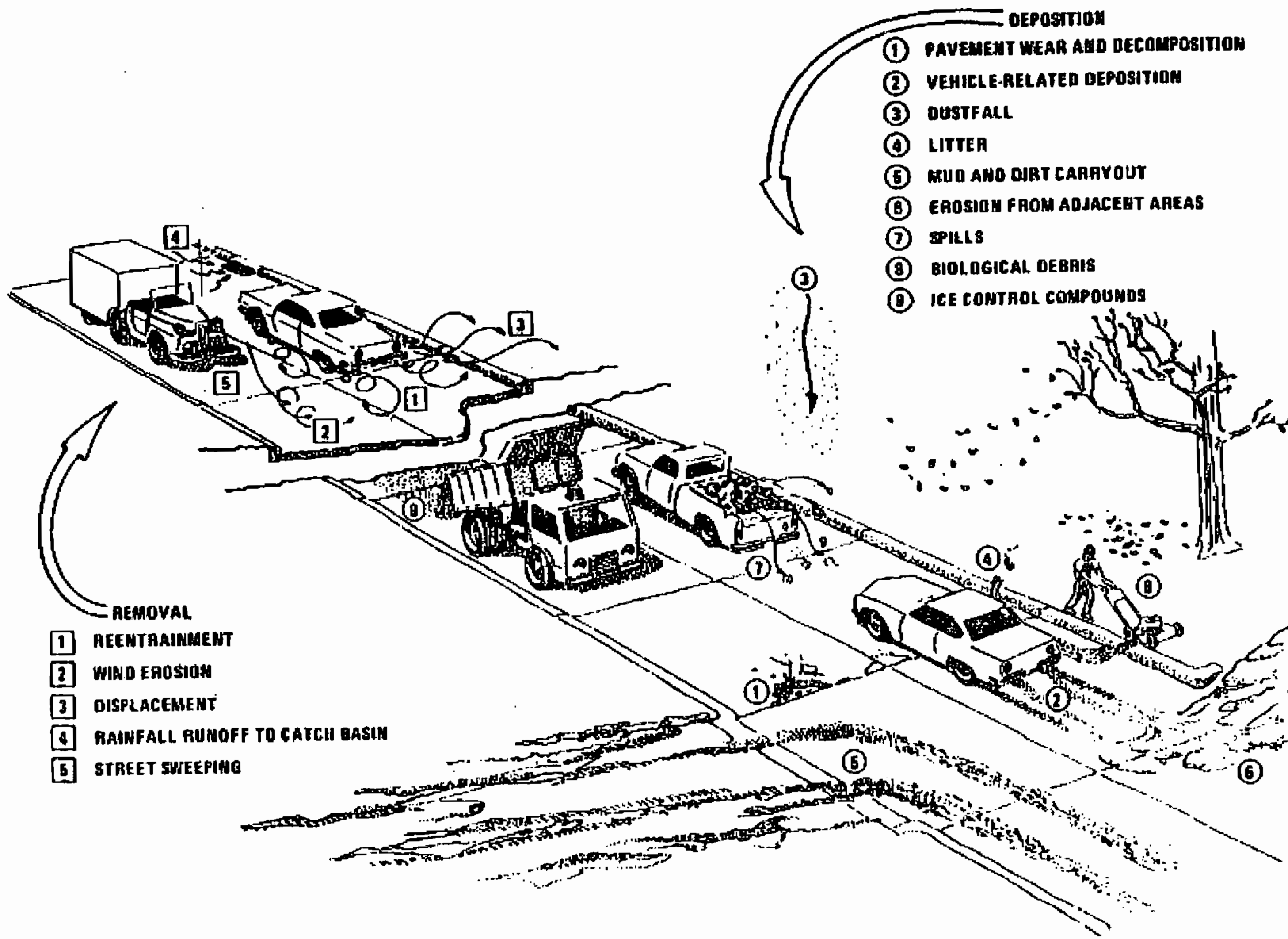



**Figure 13.2.1-1. Deposition and removal processes.**

13.2.1.3 Predictive Emission Factor Equations[10,29]

The quantity of particulate emissions from resuspension of loose material on the road surface due to vehicle travel on a dry paved road may be estimated using the following empirical expression:

$$E = k\,(sL)^{0.91} \times (W)^{1.02} \qquad (1)$$

where: E = particulate emission factor (having units matching the units of k),
k = particle size multiplier for particle size range and units of interest (see below),
$sL$ = road surface silt loading (grams per square meter) ($g/m^2$), and
W = average weight (tons) of the vehicles traveling the road.

It is important to note that Equation 1 calls for the average weight of all vehicles traveling the road. For example, if 99 percent of traffic on the road are 2 ton cars/trucks while the remaining 1 percent consists of 20 ton trucks, then the mean weight "W" is 2.2 tons. More specifically, Equation 1 is *not* intended to be used to calculate a separate emission factor for each vehicle weight class. Instead, only one emission factor should be calculated to represent the "fleet" average weight of all vehicles traveling the road.

The particle size multiplier (k) above varies with aerodynamic size range as shown in Table 13.2.1-1. To determine particulate emissions for a specific particle size range, use the appropriate value of k shown in Table 13.2.1-1.

To obtain the total emissions factor, the emission factors for the exhaust, brake wear and tire wear obtained from either EPA's MOBILE6.2[27] or MOVES2010[29] model should be added to the emissions factor calculated from the empirical equation.

Table 13.2.1-1. PARTICLE SIZE MULTIPLIERS FOR PAVED ROAD EQUATION

| Size range[a] | Particle Size Multiplier k[b] | | |
|---|---|---|---|
| | g/VKT | g/VMT | lb/VMT |
| PM-2.5[c] | 0.15 | 0.25 | 0.00054 |
| PM-10 | 0.62 | 1.00 | 0.0022 |
| PM-15 | 0.77 | 1.23 | 0.0027 |
| PM-30[d] | 3.23 | 5.24 | 0.011 |

[a] Refers to airborne particulate matter (PM-x) with an aerodynamic diameter equal to or less than x micrometers

[b] Units shown are grams per vehicle kilometer traveled (g/VKT), grams per vehicle mile traveled (g/VMT), and pounds per vehicle mile traveled (lb/VMT). The multiplier k includes unit conversions to produce emission factors in the units shown for the indicated size range from the mixed units required in Equation 1.

[c] The k-factors for $PM_{2.5}$ were based on the average $PM_{2.5}$:$PM_{10}$ ratio of test runs in Reference 30.

[d] PM-30 is sometimes termed "suspendable particulate" (SP) and is often used as a surrogate for TSP.

Equation 1 is based on a regression analysis of 83 tests for PM-10.[3, 5-6, 8, 27-29, 31-36] Sources tested include public paved roads, as well as controlled and uncontrolled industrial paved roads. The majority of tests involved freely flowing vehicles traveling at constant speed on relatively level roads. However, 22 tests of slow moving or "stop-and-go" traffic or vehicles under load were available for inclusion in the data base.[32-36] Engine exhaust, tire wear and break wear were subtracted from the emissions measured in the test programs prior to stepwise regression to determine Equation 1.[37, 39] The equations retain the quality rating of A (D for PM-2.5), if applied within the range of source conditions that were tested in developing the equation as follows:

| | |
|---|---|
| Silt loading: | 0.03 - 400 $g/m^2$<br>0.04 - 570 grains/square foot ($ft^2$) |
| Mean vehicle weight: | 1.8 - 38 megagrams (Mg)<br>2.0 - 42 tons |
| Mean vehicle speed: | 1 - 88 kilometers per hour (kph)<br>1 - 55 miles per hour (mph) |

The upper and lower 95% confidence levels of equation 1 for $PM_{10}$ is best described with equations using an exponents of 1.14 and 0.677 for silt loading and an exponents of 1.19 and 0.85 for weight. Users are cautioned that application of equation 1 outside of the range of variables and operating conditions specified above, e.g., application to roadways or road networks with speeds above 55 mph and average vehicle weights of 42 tons, will result in emission estimates with a higher level of uncertainty. In these situations, users are encouraged to consider an assessment of the impacts of the influence of extrapolation to the overall emissions and alternative methods that are equally or more plausible in light of local emissions data and/or ambient concentration or compositional data.

To retain the quality rating for the emission factor equation when it is applied to a specific paved road, it is necessary that reliable correction parameter values for the specific road in question be determined. With the exception of limited access roadways, which are difficult to sample, the collection and use of site-specific silt loading (sL) data for public paved road emission inventories are strongly recommended. The field and laboratory procedures for determining surface material silt content and surface dust loading are summarized in Appendices C.1 and C.2. In the event that site-specific values cannot be obtained, an appropriate value for a paved public road may be selected from the values in Table 13.2.1-2, but the quality rating of the equation should be reduced by 2 levels.

Equation 1 may be extrapolated to average uncontrolled conditions (but including natural mitigation) under the simplifying assumption that annual (or other long-term) average emissions are inversely proportional to the frequency of measurable (> 0.254 mm [ 0.01 inch]) precipitation by application of a precipitation correction term. The precipitation correction term can be applied on a daily or an hourly basis [26, 38].

For the daily basis, Equation 1 becomes:

$$E_{ext} = [\ k\ (sL)^{0.91} \times (W)^{1.02}\ ]\ (1 - P/4N) \qquad (2)$$

where $k$, $sL$, $W$, and $S$ are as defined in Equation 1 and

$E_{ext}$ = annual or other long-term average emission factor in the same units as $k$,

$P$ = number of "wet" days with at least 0.254 mm (0.01 in) of precipitation during the averaging period, and

$N$ = number of days in the averaging period (e.g., 365 for annual, 91 for seasonal, 30 for monthly).

Note that the assumption leading to Equation 2 is based on analogy with the approach used to develop long-term average unpaved road emission factors in Section 13.2.2. However, Equation 2 above incorporates an additional factor of "4" in the denominator to account for the fact that paved roads dry more quickly than unpaved roads and that the precipitation may not occur over the complete 24-hour day.

For the hourly basis, equation 1 becomes:

$$E_{ext} = [\ k\ (sL)^{0.91} \times (W)^{1.02}\ ]\ (1 - 1.2P/N) \qquad (3)$$

where $k$, $sL$, $W$, and $S$ are as defined in Equation 1 and

$E_{ext}$ = annual or other long-term average emission factor in the same units as $k$,

$P$ = number of hours with at least 0.254 mm (0.01 in) of precipitation during the averaging period, and

$N$ = number of hours in the averaging period (e.g., 8760 for annual, 2124 for season 720 for monthly)

Note: In the hourly moisture correction term (1-1.2P/N) for equation 3, the 1.2 multiplier is applied to account for the residual mitigative effect of moisture. For most applications, this equation will produce satisfactory results. Users should select a time interval to include sufficient "dry" hours such that a reasonable emissions averaging period is evaluated. For the special case where this equation is used to calculate emissions on an hour by hour basis, such as would be done in some emissions modeling situations, the moisture correction term should be modified so that the moisture correction "credit" is applied to the first hours following cessation of precipitation. In this special case, it is suggested that this 20% "credit" be applied on a basis of one hour credit for each hour of precipitation up to a maximum of 12 hours.

Note that the assumption leading to Equation 3 is based on analogy with the approach used to develop long-term average unpaved road emission factors in Section 13.2.2.

Figure 13.2.1-2 presents the geographical distribution of "wet" days on an annual basis for the United States. Maps showing this information on a monthly basis are available in the *Climatic Atlas of the United States*[23]. Alternative sources include other Department of Commerce publications (such as local climatological data summaries). The National Climatic Data Center (NCDC) offers several products that provide hourly precipitation data. In particular, NCDC offers *Solar and Meteorological Surface Observation Network 1961-1990* (SAMSON) CD-ROM, which contains 30 years worth of hourly meteorological data for first-order National Weather Service locations. Whatever meteorological data are used, the source of that data and the averaging period should be clearly specified.

It is emphasized that the simple assumption underlying Equations 2 and 3 has not been verified in any rigorous manner. For that reason, the quality ratings for Equations 2 and 3 should be downgraded one letter from the rating that would be applied to Equation 1.

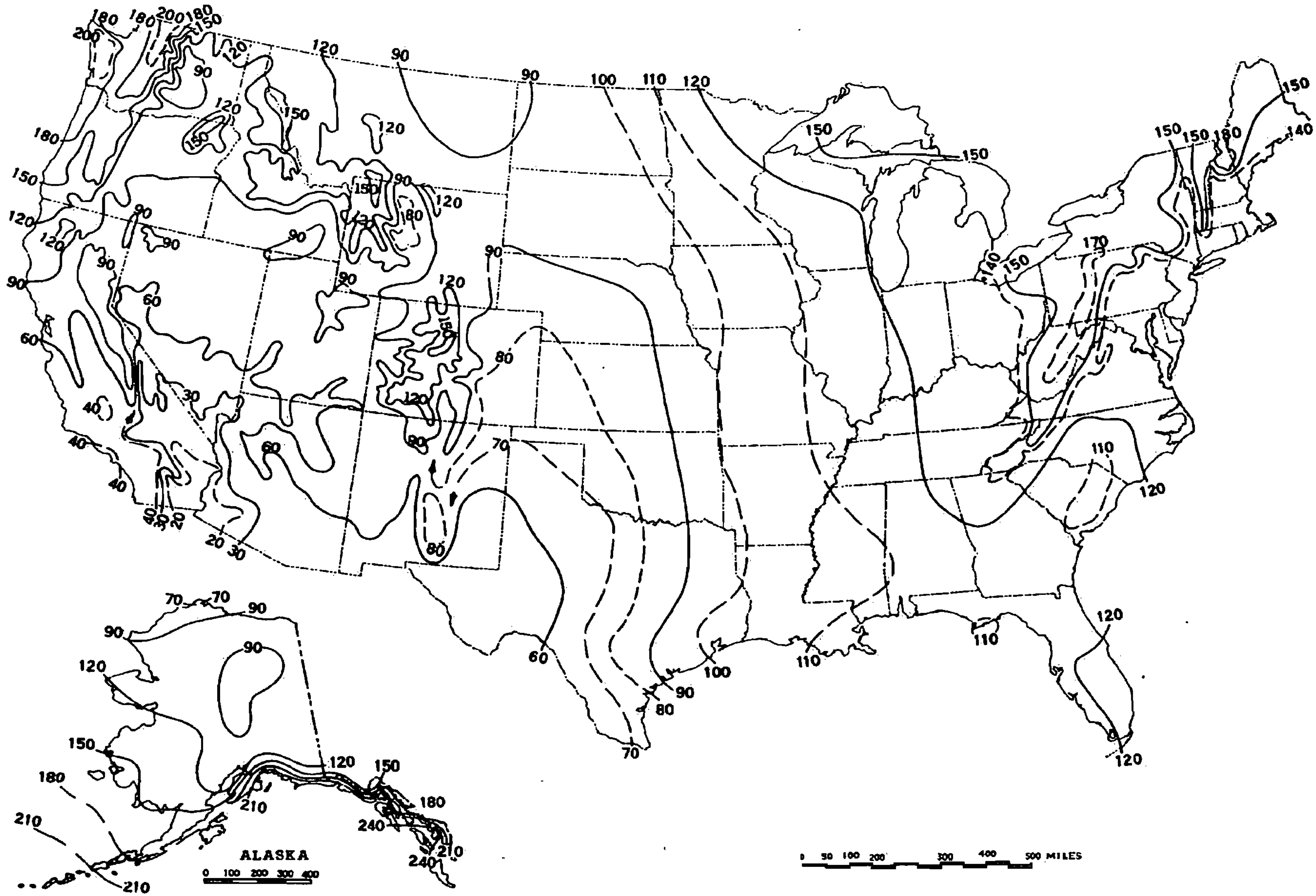



**Figure 13.2.1-2. Mean number of days with 0.01 inch or more of precipitation in the United States.**

Table 13.2.1-2 presents recommended default silt loadings for normal baseline conditions and for wintertime baseline conditions in areas that experience frozen precipitation with periodic application of antiskid material[24]. The winter baseline is represented as a multiple of the non-winter baseline, depending on the ADT value for the road in question. As shown, a multiplier of 4 is applied for low volume roads (< 500 ADT) to obtain a wintertime baseline silt loading of 4 X 0.6 = 2.4 g/m$^2$.

Table 13.2.1-2. Ubiquitous Silt Loading Default Values with Hot Spot Contributions from Anti-Skid Abrasives (g/m$^2$)

| ADT Category | < 500 | 500-5,000 | 5,000-10,000 | > 10,000 |
|---|---|---|---|---|
| Ubiquitous Baseline g/m$^2$ | 0.6 | 0.2 | 0.06 | 0.03<br>0.015 limited access |
| Ubiquitous Winter Baseline Multiplier during months with frozen precipitation | X4 | X3 | X2 | X1 |
| Initial peak additive contribution from application of antiskid abrasive (g/m$^2$) | 2 | 2 | 2 | 2 |
| Days to return to baseline conditions (assume linear decay) | 7 | 3 | 1 | 0.5 |

It is suggested that an additional (but temporary) silt loading contribution of 2 g/m$^2$ occurs with each application of antiskid abrasive for snow/ice control. This was determined based on a typical application rate of 500 lb per lane mile and an initial silt content of 1 % silt content. Ordinary rock salt and other chemical deicers add little to the silt loading, because most of the chemical dissolves during the snow/ice melting process.

To adjust the baseline silt loadings for mud/dirt trackout, the number of trackout points is required. It is recommended that in calculating $PM_{10}$ emissions, six additional miles of road be added for each active trackout point from an active construction site, to the paved road mileage of the specified category within the county. In calculating $PM_{2.5}$ emissions, it is recommended that three additional miles of road be added for each trackout point from an active construction site.

It is suggested the number of trackout points for activities other than road and building construction areas be related to land use. For example, in rural farming areas, each mile of paved road would have a specified number of trackout points at intersections with unpaved roads. This value could be estimated from the unpaved road density (mi/sq. mi.).

The use of a default value from Table 13.2.1-2 should be expected to yield only an order-of-magnitude estimate of the emission factor. Public paved road silt loadings are dependent upon: traffic characteristics (speed, ADT, and fraction of heavy vehicles); road characteristics (curbs, number of lanes, parking lanes); local land use (agriculture, new residential construction) and regional/seasonal factors (snow/ice controls, wind blown dust). As a result, the collection and use of site-specific silt loading data is highly recommended. In the event that default silt loading values are used, the quality ratings for the equation should be downgraded 2 levels.

Limited access roadways pose severe logistical difficulties in terms of surface sampling, and few silt loading data are available for such roads. Nevertheless, the available data do not suggest great variation in silt loading for limited access roadways from one part of the country to another. For annual conditions, a default value of 0.015 $g/m^2$ is recommended for limited access roadways.[9,22] Even fewer of the available data correspond to worst-case situations, and elevated loadings are observed to be quickly depleted because of high traffic speeds and high ADT rates. A default value of 0.2 $g/m^2$ is recommended for short periods of time following application of snow/ice controls to limited access roads.[22]

The limited data on silt loading values for industrial roads have shown as much variability as public roads. Because of the variations of traffic conditions and the use of preventive mitigative controls, the data probably do not reflect the full extent of the potential variation in silt loading on industrial roads. However, the collection of site specific silt loading data from industrial roads is easier and safer than for public roads. Therefore, the collection and use of site-specific silt loading data is preferred and is highly recommended. In the event that site-specific values cannot be obtained, an appropriate value for an industrial road may be selected from the mean values given in Table 13.2.1-3, but the quality rating of the equation should be reduced by 2 levels.

The predictive accuracy of Equation 1 requires thorough on-site characterization of road silt loading. Road surface sampling is time-consuming and potentially hazardous because of the need to block traffic lanes. In addition, large number of samples is required to represent spatial and temporal variations across roadway networks. Mobile monitoring is a new alternative silt loading or road dust emission characterization method for either paved or unpaved roads. It utilizes a test vehicle that generates and monitors its own dust plume concentration (mass basis) at a fixed sampling probe location. A calibration factor is needed for each mobile monitoring configuration (test vehicle and sampling system), to convert the relative dust emission intensity to an equivalent silt loading or emission factor. Typically, portable continuous particle concentration monitors do not comply with Federal Reference Method (FRM) standards. Therefore, a controlled study must be performed to correlate the portable monitor response to the road silt loading or size specific particle concentration measured with an approved FRM sampling system. In the calibration tests, multiple test conditions should be performed to provide an average correlation with known precision and to accommodate variations in road silt loading, vehicle speed, road dust characteristics and other road conditions that may influence mobile monitoring measurements or emissions characteristics. Because the paved road dust emissions are also dependent on the average vehicle weight for the road segment, it is important that the weight of the test vehicle correspond closely to the average vehicle weight for the road segment or be adjusted using the average vehicle weight relationship in Equation 1. In summary, it is believed that the Mobile Monitoring Method will provide improved capabilities to provide reliable temporally and spatially resolved silt loading or emissions factors with increased coverage, improved safety, reduced traffic interference and decreased cost.[40,41,42]

Table 13.2.1-3 (Metric And English Units). TYPICAL SILT CONTENT AND LOADING VALUES FOR PAVED ROADS AT INDUSTRIAL FACILITIES [a]

| Industry | No. of Sites | No. Of Samples | Silt Content (%) | | No. of Travel Lanes | Total Loading x $10^{-3}$ | | | Silt Loading ($g/m^2$) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Range | Mean | | Range | Mean | Units[b] | Range | Mean |
| Copper smelting | 1 | 3 | 15.4-21.7 | 19.0 | 2 | 12.9 - 19.5<br>45.8 - 69.2 | 15.9<br>55.4 | kg/km<br>lb/mi | 188-400 | 292 |
| Iron and steel production | 9 | 48 | 1.1-35.7 | 12.5 | 2 | 0.006 - 4.77<br>0.020 -16.9 | 0.495<br>1.75 | kg/km<br>lb/mi | 0.09-79 | 9.7 |
| Asphalt batching | 1 | 3 | 2.6 - 4.6 | 3.3 | 1 | 12.1 - 18.0<br>43.0 - 64.0 | 14.9<br>52.8 | kg/km<br>lb/mi | 76-193 | 120 |
| Concrete batching | 1 | 3 | 5.2 - 6.0 | 5.5 | 2 | 1.4 - 1.8<br>5.0 - 6.4 | 1.7<br>5.9 | kg/km<br>lb/mi | 11-12 | 12 |
| Sand and gravel processing | 1 | 3 | 6.4 - 7.9 | 7.1 | 1 | 2.8 - 5.5<br>9.9 - 19.4 | 3.8<br>13.3 | kg/km<br>lb/mi | 53-95 | 70 |
| Municipal solid waste landfill | 2 | 7 | | - | 2 | - | | | 1.1-32.0 | 7.4 |
| Quarry | 1 | 6 | | - | 2 | - | | | 2.4-14 | 8.2 |
| Corn wet mills | 3 | 15 | | - | 2 | - | | | 0.05 – 2.9 | 1.1 |

[a] References 1-2,5-6,11-13. Values represent samples collected from *industrial* roads. Public road silt loading values are presented in Table-13.2.1-2. Dashes indicate information not available.[b] Multiply entries by 1000 to obtain stated units; kilograms per kilometer (kg/km) and pounds per mile (lb/mi).

### 13.2.1.4 Controls[6,25]

Because of the importance of the silt loading, control techniques for paved roads attempt either to prevent material from being deposited onto the surface (preventive controls) or to remove from the travel lanes any material that has been deposited (mitigative controls). Covering of loads in trucks, and the paving of access areas to unpaved lots or construction sites, are examples of preventive measures. Examples of mitigative controls include vacuum sweeping, water flushing, and broom sweeping and flushing. Actual control efficiencies for any - of these techniques can be highly variable. Locally measured silt loadings before and after the application of controls is the preferred method to evaluate controls. It is particularly important to note that street sweeping of gutters and curb areas may actually increase the silt loading on the traveled portion of the road. Redistribution of loose material onto the travel lanes will actually produce a short-term increase in the emissions.

In general, preventive controls are usually more cost effective than mitigative controls. The cost-effectiveness of mitigative controls falls off dramatically as the size of an area to be treated increases. The cost-effectiveness of mitigative measures is also unfavorable if only a short period of time is required for the road to return to equilibrium silt loading condition. That is to say, the number and length of public roads within most areas of interest preclude any widespread and routine use of mitigative controls. On the other hand, because of the more limited scope of roads at an industrial site, mitigative measures may be used quite successfully (especially in situations where truck spillage occurs). Note, however, that public agencies could make effective use of mitigative controls to remove sand/salt from roads after the winter ends.

Because available controls will affect the silt loading, controlled emission factors may be obtained by substituting controlled silt loading values into the equation. (Emission factors from controlled industrial roads were used in the development of the equation.) The collection of surface loading samples from treated, as well as baseline (untreated), roads provides a means to track effectiveness of the controls over time. The use of Mobile Monitoring Methodologies provide an improved means to track progress in controlling silt loading values.

### 13.2.1.5 Changes since Fifth Edition

The following changes were made since the publication of the Fifth Edition of AP-42:

October 2002

1) The particle size multiplier for $PM_{2.5}$ was revised to 25% of $PM_{10}$. The approximately 55% reduction was a result of emission testing using FRM monitors. The monitoring was specifically intended to evaluate the PM-2.5 component of the emissions.

2) Default silt loading values were included in Table 13.2.1-2 replacing the Tables and Figures containing silt loading statistical information.

3) Editorial changes within the text were made indicating the possible causes of variations in the silt loading between roads within and among different locations. The uncertainty of using the default silt loading value was discussed.

4) Section 13.2.1.1 was revised to clarify the role of dust loading in resuspension. Additional minor text changes were made.

5) Equations 2 and 3, Figure 13.2.1-2, and text were added to incorporate natural mitigation into annual or other long-term average emission factors.

December 2003

1) The emission factor equation was adjusted to remove the component of particulate emissions- from exhaust, brake wear, and tire wear. A parameter C representing these emissions was included in the predictive equation. The parameter C varied with aerodynamic size range of the particulate matter. Table 13.2.1-2 was added to present the new coefficients.

2) The default silt loading values in Table 13.2.1-3 were revised to incorporate the results from a recent analysis of silt loading data.

November 2006

1) The $PM_{2.5}$ particle size multiplier was revised to 15% of $PM_{10}$ as the result of wind tunnel studies of a variety of dust emitting surface materials.

2) References were rearranged and renumbered.

January 2011

1) The empirical predictive equation was revised. The revision is based upon stepwise regression of 83 profile emissions tests and an adjustment of individual test data for the exhaust; break wear and tire wear emissions prior to regression of the data.

2) The C term is removed from the empirical predictive equation and Table 13.2.1-2 with the C term values is removed since the exhaust; break wear and tire wear emissions were no longer part of the regressed data.

3) The $PM_{2.5}$ particle size multiplier was revised to 25% of $PM_{10}$ since the $PM_{10}$ test data used to develop the equation did not meet the necessary $PM_{10}$ concentrations for a ratio of 15%.

4) The lower speed of the vehicle speed range supported by the empirical predictive equation was revised to 1 mph.

5) Information was added on an improved methodology to develop spatially and temporally resolved silt loadings or emissions factors by Mobile Monitoring Methodologies.

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## 13.2.2 Unpaved Roads

### 13.2.2.1 General

When a vehicle travels an unpaved road, the force of the wheels on the road surface causes pulverization of surface material. Particles are lifted and dropped from the rolling wheels, and the road surface is exposed to strong air currents in turbulent shear with the surface. The turbulent wake behind the vehicle continues to act on the road surface after the vehicle has passed.

The particulate emission factors presented in the previous draft version of this section of AP-42, dated October 2001, implicitly included the emissions from vehicles in the form of exhaust, brake wear, and tire wear as well as resuspended road surface material[25]. EPA included these sources in the emission factor equation for unpaved public roads (equation 1b in this section) since the field testing data used to develop the equation included both the direct emissions from vehicles and emissions from resuspension of road dust.

This version of the unpaved public road emission factor equation only estimates particulate emissions from resuspended road surface material [23, 26]. The particulate emissions from vehicle exhaust, brake wear, and tire wear are now estimated separately using EPA's MOBILE6.2 [24]. This approach eliminates the possibility of double counting emissions. Double counting results when employing the previous version of the emission factor equation in this section and MOBILE6.2 to estimate particulate emissions from vehicle traffic on unpaved public roads. It also incorporates the decrease in exhaust emissions that has occurred since the unpaved public road emission factor equation was developed. The previous version of the unpaved public road emission factor equation includes estimates of emissions from exhaust, brake wear, and tire wear based on emission rates for vehicles in the 1980 calendar year fleet. The amount of PM released from vehicle exhaust has decreased since 1980 due to lower new vehicle emission standards and changes in fuel characteristics.

### 13.2.2.2 Emissions Calculation And Correction Parameters[1-6]

The quantity of dust emissions from a given segment of unpaved road varies linearly with the volume of traffic. Field investigations also have shown that emissions depend on source parameters that characterize the condition of a particular road and the associated vehicle traffic. Characterization of these source parameters allow for "correction" of emission estimates to specific road and traffic conditions present on public and industrial roadways.

Dust emissions from unpaved roads have been found to vary directly with the fraction of silt (particles smaller than 75 micrometers [µm] in diameter) in the road surface materials.[1] The silt fraction is determined by measuring the proportion of loose dry surface dust that passes a 200-mesh screen, using the ASTM-C-136 method. A summary of this method is contained in Appendix C of AP-42. Table 13.2.2-1 summarizes measured silt values for industrial unpaved roads. Table 13.2.2-2 summarizes measured silt values for public unpaved roads. It should be noted that the ranges of silt content vary over two orders of magnitude. Therefore, the use of data from this table can potentially introduce considerable error. Use of this data is strongly discouraged when it is feasible to obtain locally gathered data.

Since the silt content of a rural dirt road will vary with geographic location, it should be measured for use in projecting emissions. As a conservative approximation, the silt content of the parent soil in the area can be used. Tests, however, show that road silt content is normally lower than in the surrounding parent soil, because the fines are continually removed by the vehicle traffic, leaving a higher percentage of coarse particles.

Other variables are important in addition to the silt content of the road surface material. For example, at industrial sites, where haul trucks and other heavy equipment are common, emissions are highly correlated with vehicle weight. On the other hand, there is far less variability in the weights of cars and pickup trucks that commonly travel publicly accessible unpaved roads throughout the United States. For those roads, the moisture content of the road surface material may be more dominant in determining differences in emission levels between, for example a hot, desert environment and a cool, moist location.

The PM-10 and TSP emission factors presented below are the outcomes from stepwise linear regressions of field emission test results of vehicles traveling over unpaved surfaces. Due to a limited amount of information available for PM-2.5, the expression for that particle size range has been scaled against the result for PM-10. Consequently, the quality rating for the PM-2.5 factor is lower than that for the PM-10 expression.

Table 13.2.2-1. TYPICAL SILT CONTENT VALUES OF SURFACE MATERIAL ON INDUSTRIAL UNPAVED ROADS[a]

| Industry | Road Use Or Surface Material | Plant Sites | No. Of Samples | Silt Content (%) | |
|---|---|---|---|---|---|
| | | | | Range | Mean |
| Copper smelting | Plant road | 1 | 3 | 16 - 19 | 17 |
| Iron and steel production | Plant road | 19 | 135 | 0.2 - 19 | 6.0 |
| Sand and gravel processing | Plant road | 1 | 3 | 4.1 - 6.0 | 4.8 |
| | Material storage area | 1 | 1 | - | 7.1 |
| Stone quarrying and processing | Plant road | 2 | 10 | 2.4 - 16 | 10 |
| | Haul road to/from pit | 4 | 20 | 5.0-15 | 8.3 |
| Taconite mining and processing | Service road | 1 | 8 | 2.4 - 7.1 | 4.3 |
| | Haul road to/from pit | 1 | 12 | 3.9 - 9.7 | 5.8 |
| Western surface coal mining | Haul road to/from pit | 3 | 21 | 2.8 - 18 | 8.4 |
| | Plant road | 2 | 2 | 4.9 - 5.3 | 5.1 |
| | Scraper route | 3 | 10 | 7.2 - 25 | 17 |
| | Haul road (freshly graded) | 2 | 5 | 18 - 29 | 24 |
| Construction sites | Scraper routes | 7 | 20 | 0.56-23 | 8.5 |
| Lumber sawmills | Log yards | 2 | 2 | 4.8-12 | 8.4 |
| Municipal solid waste landfills | Disposal routes | 4 | 20 | 2.2 - 21 | 6.4 |

[a]References 1,5-15.

The following empirical expressions may be used to estimate the quantity in pounds (lb) of size-specific particulate emissions from an unpaved road, per vehicle mile traveled (VMT):

For vehicles traveling on unpaved surfaces at industrial sites, emissions are estimated from the following equation:

$$E = k\,(s/12)^a (W/3)^b \qquad (1a)$$

and, for vehicles traveling on publicly accessible roads, dominated by light duty vehicles, emissions may be estimated from the following:

$$E = \frac{k\,(s/12)^a (S/30)^d}{(M/0.5)^c} - C \qquad (1b)$$

where k, a, b, c and d are empirical constants (Reference 6) given below and

E = size-specific emission factor (lb/VMT)
s = surface material silt content (%)
W = mean vehicle weight (tons)
M = surface material moisture content (%)
S = mean vehicle speed (mph)
*C* = emission factor for 1980's vehicle fleet exhaust, brake wear and tire wear.

The source characteristics s, W and M are referred to as correction parameters for adjusting the emission estimates to local conditions. The metric conversion from lb/VMT to grams (g) per vehicle kilometer traveled (VKT) is as follows:

1 lb/VMT = 281.9 g/VKT

The constants for Equations 1a and 1b based on the stated aerodynamic particle sizes are shown in Tables 13.2.2-2 and 13.2.2-4. The PM-2.5 particle size multipliers (k-factors) are taken from Reference 27.

Table 13.2.2-2. CONSTANTS FOR EQUATIONS 1a AND 1b

| Constant | Industrial Roads (Equation 1a) | | | Public Roads (Equation 1b) | | |
|---|---|---|---|---|---|---|
| | PM-2.5 | PM-10 | PM-30* | PM-2.5 | PM-10 | PM-30* |
| k (lb/VMT) | 0.15 | 1.5 | 4.9 | 0.18 | 1.8 | 6.0 |
| a | 0.9 | 0.9 | 0.7 | 1 | 1 | 1 |
| b | 0.45 | 0.45 | 0.45 | - | - | - |
| c | - | - | - | 0.2 | 0.2 | 0.3 |
| d | - | - | - | 0.5 | 0.5 | 0.3 |
| Quality Rating | B | B | B | B | B | B |

*Assumed equivalent to total suspended particulate matter (TSP)
"-" = not used in the emission factor equation

Table 13.2.2-2 also contains the quality ratings for the various size-specific versions of Equation 1a and 1b. The equation retains the assigned quality rating, if applied within the ranges of source conditions, shown in Table 13.2.2-3, that were tested in developing the equation:

Table 13.2.2-3. RANGE OF SOURCE CONDITIONS USED IN DEVELOPING EQUATION 1a AND 1b

| Emission Factor | Surface Silt Content, % | Mean Vehicle Weight | | Mean Vehicle Speed | | Mean No. of Wheels | Surface Moisture Content, % |
|---|---|---|---|---|---|---|---|
| | | Mg | ton | km/hr | mph | | |
| Industrial Roads (Equation 1a) | 1.8-25.2 | 1.8-260 | 2-290 | 8-69 | 5-43 | 4-17[a] | 0.03-13 |
| Public Roads (Equation 1b) | 1.8-35 | 1.4-2.7 | 1.5-3 | 16-88 | 10-55 | 4-4.8 | 0.03-13 |

[a] See discussion in text.

As noted earlier, the models presented as Equations 1a and 1b were developed from tests of traffic on unpaved surfaces. Unpaved roads have a hard, generally nonporous surface that usually dries quickly after a rainfall or watering, because of traffic-enhanced natural evaporation. (Factors influencing how fast a road dries are discussed in Section 13.2.2.3, below.) The quality ratings given above pertain to the mid-range of the measured source conditions for the equation. A higher mean vehicle weight and a higher than normal traffic rate may be justified when performing a worst-case analysis of emissions from unpaved roads.

The emission factors for the exhaust, brake wear and tire wear of a 1980's vehicle fleet (*C*) was obtained from EPA's MOBILE6.2 model [23]. The emission factor also varies with aerodynamic size range as shown in Table 13.2.2-4

Table 13.2.2-4. EMISSION FACTOR FOR 1980'S VEHICLE FLEET EXHAUST, BRAKE WEAR AND TIRE WEAR

| Particle Size Range[a] | *C*, Emission Factor for Exhaust, Brake Wear and Tire Wear[b] lb/VMT |
|---|---|
| $PM_{2.5}$ | 0.00036 |
| $PM_{10}$ | 0.00047 |
| $PM_{30}$[c] | 0.00047 |

[a] Refers to airborne particulate matter (PM-x) with an aerodynamic diameter equal to or less than x micrometers.
[b] Units shown are pounds per vehicle mile traveled (lb/VMT).
[c] PM-30 is sometimes termed "suspendable particulate" (SP) and is often used as a surrogate for TSP.

It is important to note that the vehicle-related source conditions refer to the average weight, speed, and number of wheels for all vehicles traveling the road. For example, if 98 percent of traffic on the road are 2-ton cars and trucks while the remaining 2 percent consists of 20-ton trucks, then the mean weight is 2.4 tons. More specifically, Equations 1a and 1b are *not* intended to be used to calculate a separate emission factor for each vehicle class within a mix of traffic on a given unpaved road. That is, in the example, one should *not* determine one factor for the 2-ton vehicles and a second factor for the 20-ton trucks. Instead, only one emission factor should be calculated that represents the "fleet" average of 2.4 tons for all vehicles traveling the road.

Moreover, to retain the quality ratings when addressing a group of unpaved roads, it is necessary that reliable correction parameter values be determined for the road in question. The field and laboratory procedures for determining road surface silt and moisture contents are given in AP-42 Appendices C.1 and C.2. Vehicle-related parameters should be developed by recording visual observations of traffic. In some cases, vehicle parameters for industrial unpaved roads can be determined by reviewing maintenance records or other information sources at the facility.

In the event that site-specific values for correction parameters cannot be obtained, then default values may be used.In the absence of site-specific silt content information, an appropriate mean value from Table 13.2.2-1 may be used as a default value, but the quality rating of the equation is reduced by two letters. Because of significant differences found between different types of road surfaces and between different areas of the country, use of the default moisture content value of 0.5 percent in Equation 1b is discouraged. The quality rating should be downgraded two letters when the default moisture content value is used. (It is assumed that readers addressing industrial roads have access to the information needed to develop average vehicle information in Equation 1a for their facility.)

The effect of routine watering to control emissions from unpaved roads is discussed below in Section 13.2.2.3, "Controls". However, all roads are subject to some natural mitigation because of rainfall and other precipitation. The Equation 1a and 1b emission factors can be extrapolated to annual average uncontrolled conditions (but including natural mitigation) under the simplifying assumption that annual average emissions are inversely proportional to the number of days with measurable (more than 0.254 mm [0.01 inch]) precipitation:

$$E_{ext} = E\ [(365 - P)/365] \tag{2}$$

where:

$E_{ext}$ = annual size-specific emission factor extrapolated for natural mitigation, lb/VMT

E = emission factor from Equation 1a or 1b

P = number of days in a year with at least 0.254 mm (0.01 in) of precipitation (see below)

Figure 13.2.2-1 gives the geographical distribution for the mean annual number of "wet" days for the United States.

Equation 2 provides an estimate that accounts for precipitation on an annual average basis for the purpose of inventorying emissions. It should be noted that Equation 2 does not account for differences in the temporal distributions of the rain events, the quantity of rain during any event, or the potential for the rain to evaporate from the road surface. In the event that a finer temporal and spatial resolution is desired for inventories of public unpaved roads, estimates can be based on a more complex set of assumptions. These assumptions include:

1. The moisture content of the road surface material is increased in proportion to the quantity of water added;
2. The moisture content of the road surface material is reduced in proportion to the Class A pan evaporation rate;
3. The moisture content of the road surface material is reduced in proportion to the traffic volume; and
4. The moisture content of the road surface material varies between the extremes observed in the area. The CHIEF Web site (http://www.epa.gov/ttn/chief/ap42/ch13/related/c13s02-2.html) has a file which contains a spreadsheet program for calculating emission factors which are temporally and spatially resolved. Information required for use of the spreadsheet program includes monthly Class A pan evaporation values, hourly meteorological data for precipitation, humidity and snow cover, vehicle traffic information, and road surface material information.

It is emphasized that <u>the simple assumption underlying Equation 2 and the more complex set of assumptions underlying the use of the procedure which produces a finer temporal and spatial resolution</u> have not been verified in any rigorous manner. For this reason, the quality ratings for either approach should be downgraded one letter from the rating that would be applied to Equation 1.

### 13.2.2.3 Controls[18-22]

A wide variety of options exist to control emissions from unpaved roads. Options fall into the following three groupings:

1. <u>Vehicle restrictions</u> that limit the speed, weight or number of vehicles on the road;

2. Surface improvement, by measures such as (a) paving or (b) adding gravel or slag to a dirt road; and

3. Surface treatment, such as watering or treatment with chemical dust suppressants.

Available control options span broad ranges in terms of cost, efficiency, and applicability. For example, traffic controls provide moderate emission reductions (often at little cost) but are difficult to enforce. Although paving is highly effective, its high initial cost is often prohibitive. Furthermore, paving is not feasible for industrial roads subject to very heavy vehicles and/or spillage of material in transport. Watering and chemical suppressants, on the other hand, are potentially applicable to most industrial roads at moderate to low costs. However, these require frequent reapplication to maintain an acceptable level of control. Chemical suppressants are generally more cost-effective than water but not in cases of temporary roads (which are common at mines, landfills, and construction sites). In summary, then, one needs to consider not only the type and volume of traffic on the road but also how long the road will be in service when developing control plans.

Vehicle restrictions. These measures seek to limit the amount and type of traffic present on the road or to lower the mean vehicle speed. For example, many industrial plants have restricted employees from driving on plant property and have instead instituted bussing programs. This eliminates emissions due to employees traveling to/from their worksites. Although the heavier average vehicle weight of the busses increases the base emission factor, the decrease in vehicle-miles-traveled results in a lower overall emission rate.

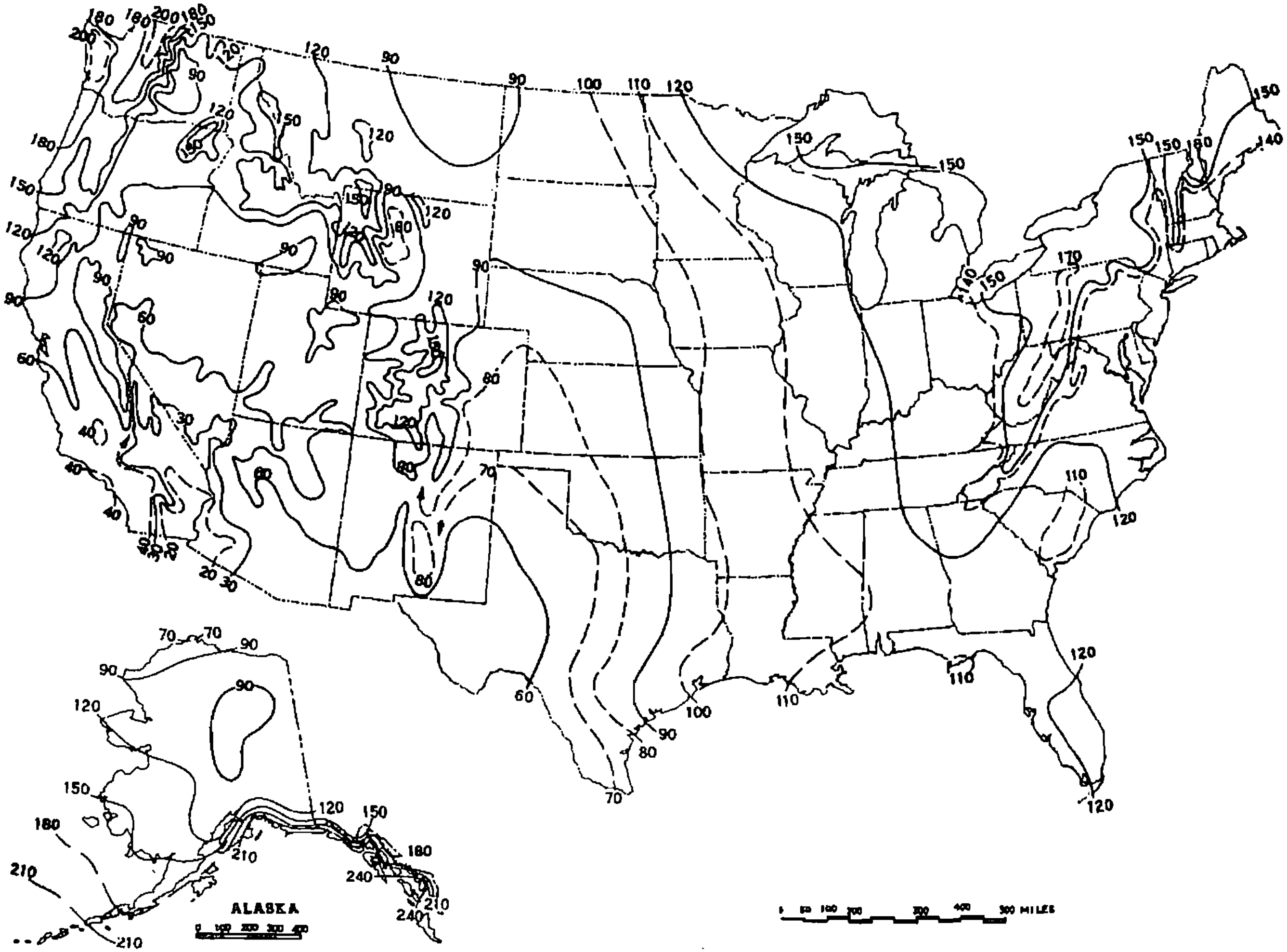


Figure 13.2.2-1. Mean number of days with 0.01 inch or more of precipitation in United States.

Surface improvements. Control options in this category alter the road surface. As opposed to the "surface treatments" discussed below, improvements are relatively "permanent" and do not require periodic retreatment.

The most obvious surface improvement is paving an unpaved road. This option is quite expensive and is probably most applicable to relatively short stretches of unpaved road with at least several hundred vehicle passes per day. Furthermore, if the newly paved road is located near unpaved areas or is used to transport material, it is essential that the control plan address routine cleaning of the newly paved road surface.

The control efficiencies achievable by paving can be estimated by comparing emission factors for unpaved and paved road conditions. The predictive emission factor equation for paved roads, given in Section 13.2.1, requires estimation of the silt loading on the traveled portion of the paved surface, which in turn depends on whether the pavement is periodically cleaned. Unless curbing is to be installed, the effects of vehicle excursion onto unpaved shoulders (berms) also must be taken into account in estimating the control efficiency of paving.

Other improvement methods cover the road surface with another material that has a lower silt content. Examples include placing gravel or slag on a dirt road. Control efficiency can be estimated by comparing the emission factors obtained using the silt contents before and after improvement. The silt content of the road surface should be determined after 3 to 6 months rather than immediately following placement. Control plans should address regular maintenance practices, such as grading, to retain larger aggregate on the traveled portion of the road.

Surface treatments refer to control options which require periodic reapplication. Treatments fall into the two main categories of (a) "wet suppression" (i. e., watering, possibly with surfactants or other additives), which keeps the road surface wet to control emissions and (b) "chemical stabilization/ treatment", which attempts to change the physical characteristics of the surface. The necessary reapplication frequency varies from several minutes for plain water under summertime conditions to several weeks or months for chemical dust suppressants.

Watering increases the moisture content, which conglomerates particles and reduces their likelihood to become suspended when vehicles pass over the surface. The control efficiency depends on how fast the road dries after water is added. This in turn depends on (a) the amount (per unit road surface area) of water added during each application; (b) the period of time between applications; (c) the weight, speed and number of vehicles traveling over the watered road during the period between applications; and (d) meteorological conditions (temperature, wind speed, cloud cover, etc.) that affect evaporation during the period.

Figure 13.2.2-2 presents a simple bilinear relationship between the instantaneous control efficiency due to watering and the resulting increase in surface moisture. The moisture ratio "M" (i.e., the x-axis in Figure 13.2.2-2) is found by dividing the surface moisture content of the watered road by the surface moisture content of the uncontrolled road. As the watered road surface dries, both the ratio M and the predicted instantaneous control efficiency (i.e., the y-axis in the figure) decrease. The figure shows that between the uncontrolled moisture content and a value twice as large, a small increase in moisture content results in a large increase in control efficiency. Beyond that, control efficiency grows slowly with increased moisture content.

Given the complicated nature of how the road dries, characterization of emissions from watered roadways is best done by collecting road surface material samples at various times between water truck passes. (Appendices C.1 and C.2 present the sampling and analysis procedures.) The moisture content measured can then be associated with a control efficiency by use of Figure 13.2.2-2. Samples that reflect average conditions during the watering cycle can take the form of either a series of samples between water applications or a single sample at the midpoint. It is essential that samples be collected during periods with active traffic on the road. Finally, because of different evaporation rates, it is recommended that samples be collected at various times during the year. If only one set of samples is to be collected, these must be collected during hot, summertime conditions.

When developing watering control plans for roads that do not yet exist, it is strongly recommended that the moisture cycle be established by sampling similar roads in the same geographic area. If the moisture cycle cannot be established by similar roads using established watering control plans, the more complex methodology used to estimate the mitigation of rainfall and other precipitation can be used to estimate the control provided by routine watering. An estimate of the maximum daytime Class A pan evaporation (based upon daily evaporation data published in the monthly Climatological Data for the state by the National Climatic Data Center) should be used to insure that adequate watering capability is available during periods of highest evaporation. The hourly precipitation values in the spreadsheet should be replaced with the equivalent inches of precipitation (where the equivalent of 1 inch of precipitation is provided by an application of 5.6 gallons of water per square yard of road). Information on the long term average annual evaporation and on the percentage that occurs between May and October was published in the Climatic Atlas (Reference 16). Figure 13.2.2-3 presents the geographical distribution for "Class A pan evaporation" throughout the United States. Figure 13.2.2-4 presents the geographical distribution of the percentage of this evaporation that occurs between May and October. The U. S. Weather Bureau Class A evaporation pan is a cylindrical metal container with a depth of 10 inches and a diameter of 48 inches. Periodic measurements are made of the changes of the water level.

The above methodology should be used <u>only for prospective analyses</u> and for designing watering programs for existing roadways. The quality rating of an emission factor for a watered road that is based on this methodology should be downgraded two letters. Periodic road surface samples should be collected and analyzed to verify the efficiency of the watering program.

As opposed to watering, chemical dust suppressants have much less frequent reapplication requirements. These materials suppress emissions by changing the physical characteristics of the existing road surface material. Many chemical unpaved road dust suppressants form a hardened surface that binds particles together. After several applications, a treated road often resembles a paved road except that the surface is not uniformly flat. Because the improved surface results in more grinding of small particles, the silt content of loose material on a highly controlled surface may be substantially higher than when the surface was uncontrolled. For this reason, the models presented as Equations 1a and 1b cannot be used to estimate emissions from chemically stabilized roads. Should the road be allowed to return to an uncontrolled state with no visible signs of large-scale cementing of material, the Equation 1a and 1b emission factors could then be used to obtain conservatively high emission estimates.

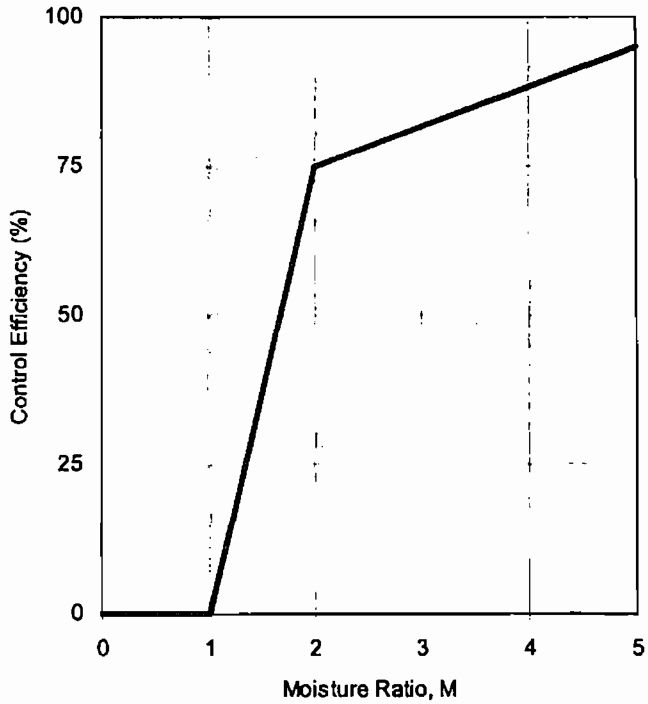


Figure 13.2.2-2. Watering control effectiveness for unpaved travel surfaces

The control effectiveness of chemical dust suppressants appears to depend on (a) the dilution rate used in the mixture; (b) the application rate (volume of solution per unit road surface area); (c) the time between applications; (d) the size, speed and amount of traffic during the period between applications; and (e) meteorological conditions (rainfall, freeze/thaw cycles, etc.) during the period. Other factors that affect the performance of dust suppressants include other traffic characteristics (e. g., cornering, track-on from unpaved areas) and road characteristics (e. g., bearing strength, grade). The variabilities in the above factors and differences between individual dust control products make the control efficiencies of chemical dust suppressants difficult to estimate. Past field testing of emissions from controlled unpaved roads has shown that chemical dust suppressants provide a PM-10 control efficiency of about 80 percent when applied at regular intervals of 2 weeks to 1 month.

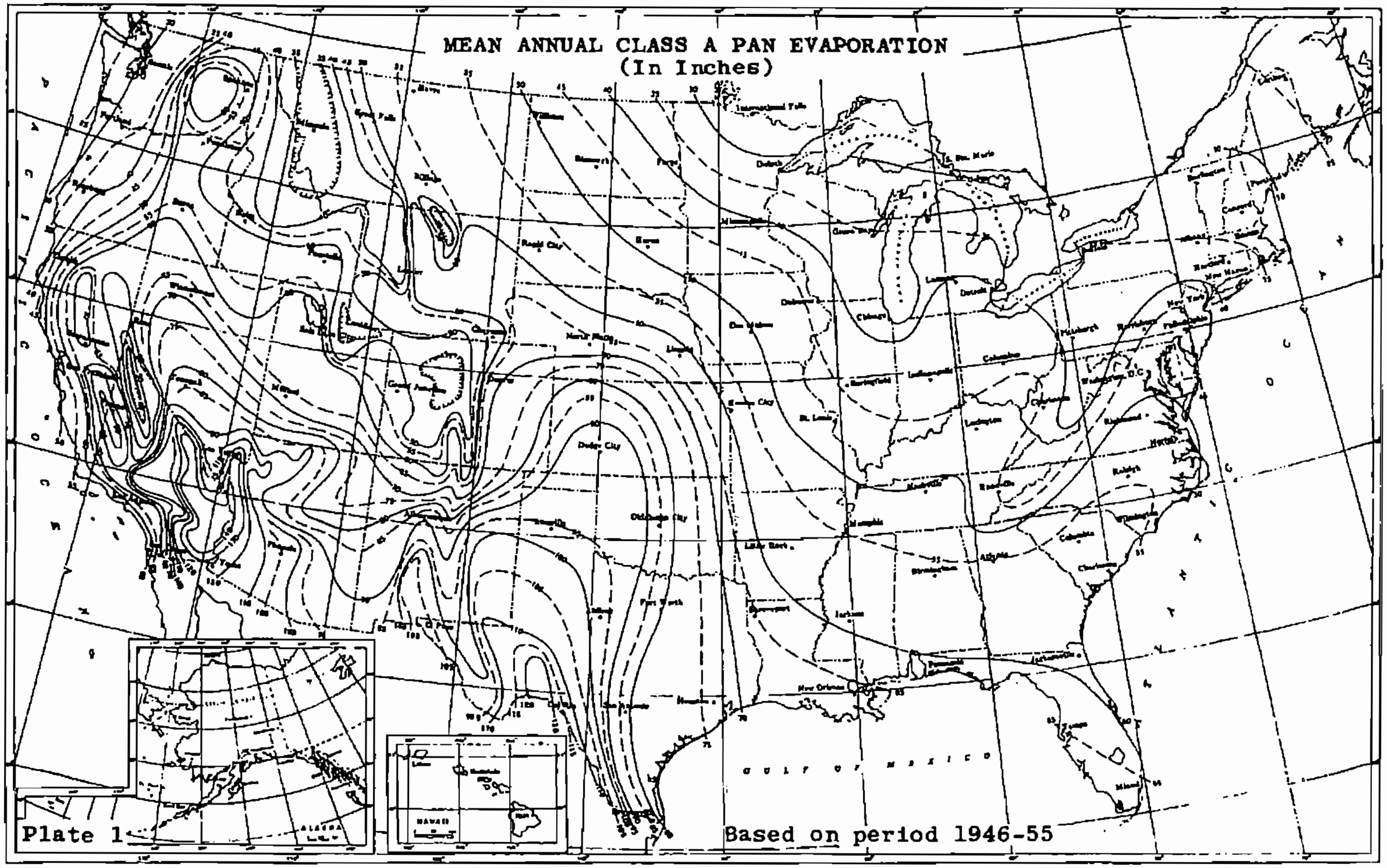


Figure 13.2.2-3. Annual evaporation data.

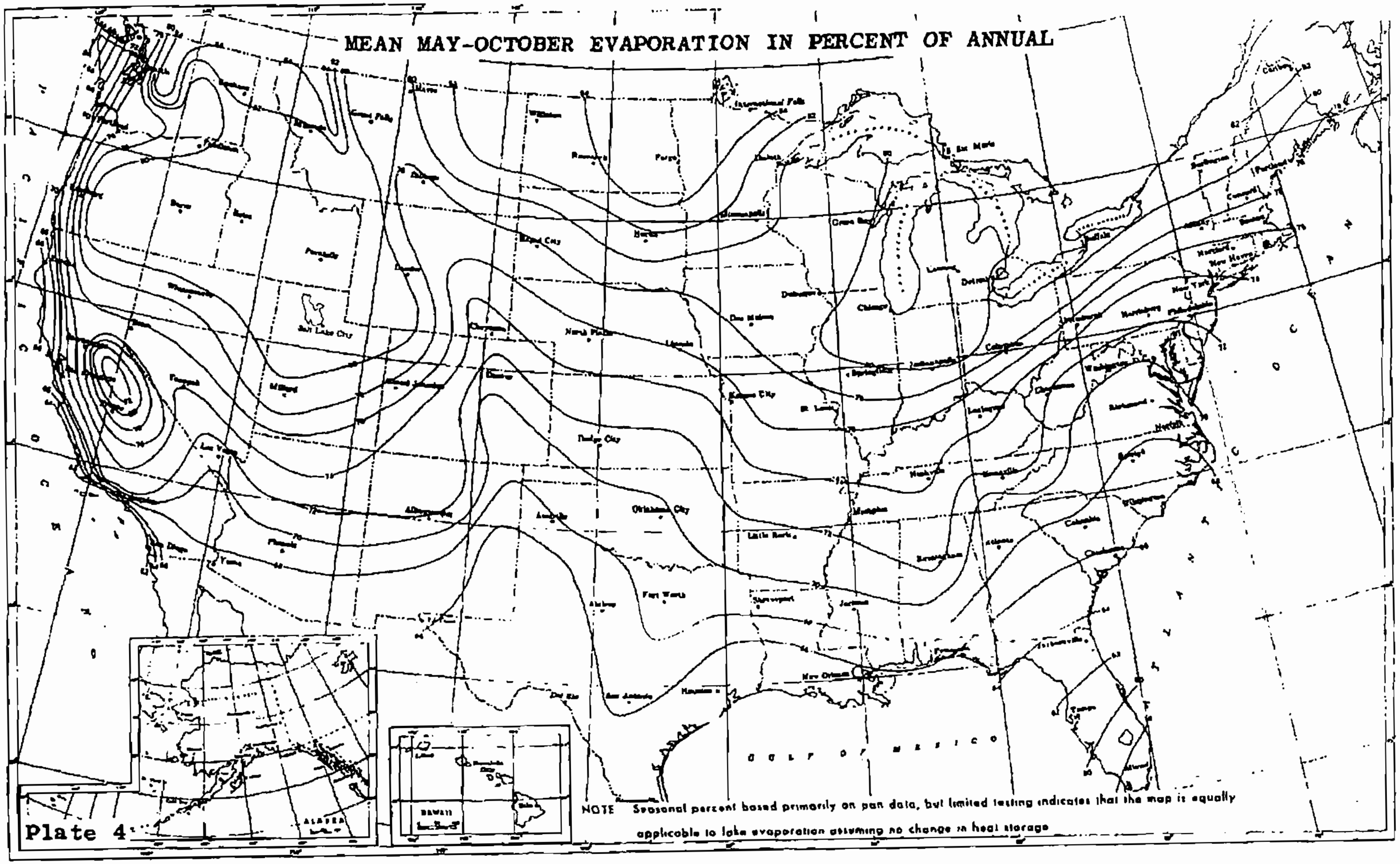


Figure 13.2.2-4. Geographical distribution of the percentage of evaporation occurring between May and October.

Petroleum resin products historically have been the dust suppressants (besides water) most widely used on industrial unpaved roads. Figure 13.2.2-5 presents a method to estimate average control efficiencies associated with petroleum resins applied to unpaved roads.[20] Several items should be noted:

1. The term "ground inventory" represents the total volume (per unit area) of petroleum resin concentrate (*not solution*) applied since the start of the dust control season.

2. Because petroleum resin products must be periodically reapplied to unpaved roads, the use of a time-averaged control efficiency value is appropriate. Figure 13.2.2-5 presents control efficiency values averaged over two common application intervals, 2 weeks and 1 month. Other application intervals will require interpolation.

3. Note that zero efficiency is assigned until the ground inventory reaches 0.05 gallon per square yard (gal/yd$^2$). Requiring a minimum ground inventory ensures that one must apply a reasonable amount of chemical dust suppressant to a road before claiming credit for emission control. Recall that the ground inventory refers to the amount of petroleum resin concentrate rather than the total solution.

As an example of the application of Figure 13.2.2-5, suppose that Equation 1a was used to estimate an emission factor of 7.1 lb/VMT for PM-10 from a particular road. Also, suppose that, starting on May 1, the road is treated with 0.221 gal/yd$^2$ of a solution (1 part petroleum resin to 5 parts water) on the first of each month through September. Then, the average controlled emission factors, shown in Table 13.2.2-5, are found.

Table 13.2-2-5. EXAMPLE OF AVERAGE CONTROLLED EMISSION FACTORS FOR SPECIFIC CONDITIONS

| Period | Ground Inventory, gal/yd$^2$ | Average Control Efficiency, %[a] | Average Controlled Emission Factor, lb/VMT |
|---|---|---|---|
| May | 0.037 | 0 | 7.1 |
| June | 0.073 | 62 | 2.7 |
| July | 0.11 | 68 | 2.3 |
| August | 0.15 | 74 | 1.8 |
| September | 0.18 | 80 | 1.4 |

[a] From Figure 13.2.2-5, ≤10 µm. Zero efficiency assigned if ground inventory is less than 0.05 gal/yd$^2$.
1 lb/VMT = 281.9 g/VKT. 1 gal/yd$^2$ = 4.531 L/m$^2$.

Besides petroleum resins, other newer dust suppressants have also been successful in controlling emissions from unpaved roads. Specific test results for those chemicals, as well as for petroleum resins and watering, are provided in References 18 through 21.

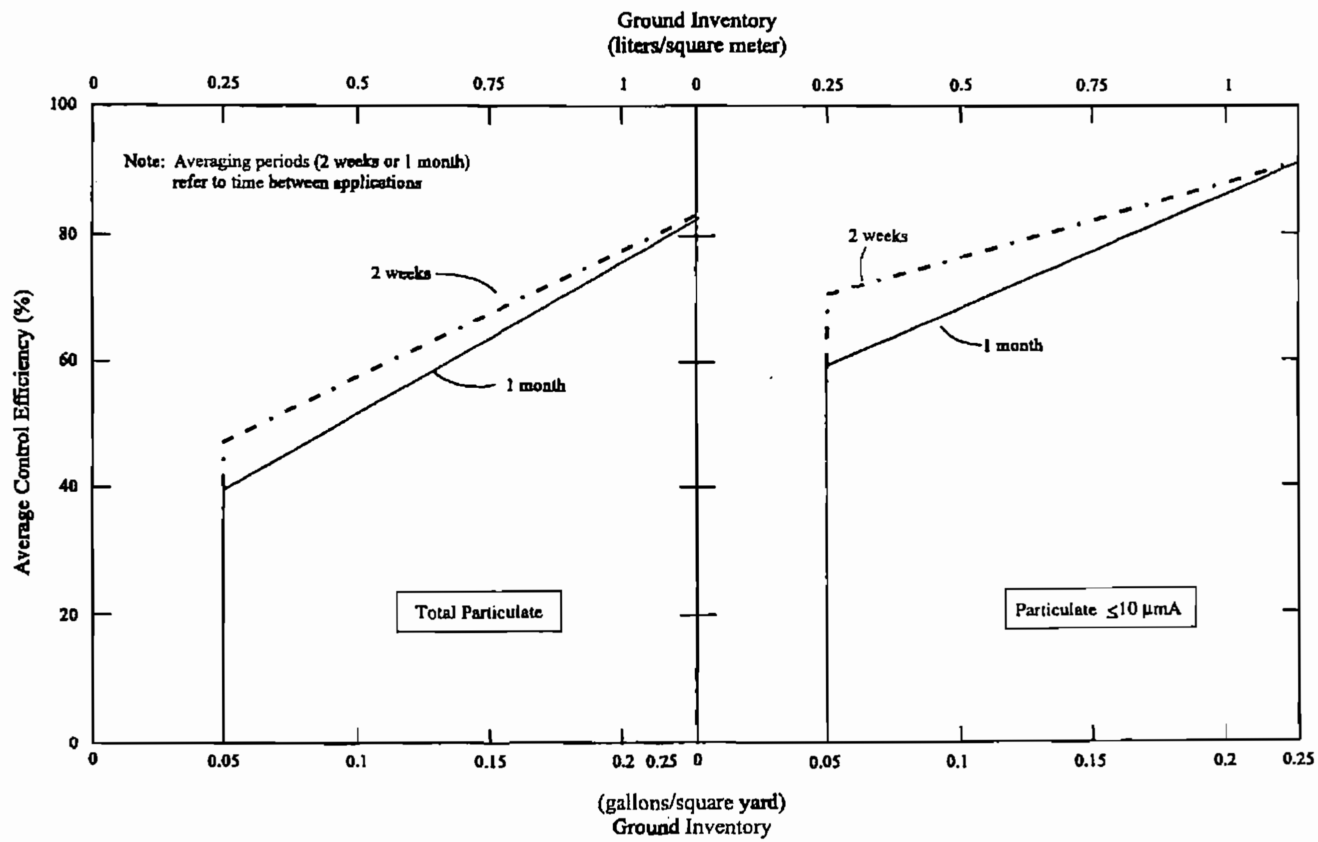


Figure 13.2.2-5. Average control efficiencies over common application intervals.

### 13.2.2.4 Updates Since The Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section since that date are summarized below. For further detail, consult the background report for this section (Reference 6).

October 1998 (Supplement E)– This was a major revision of this section. Significant changes to the text and the emission factor equations were made.

October 2001 – Separate emission factors for unpaved surfaces at industrial sites and publicly accessible roads were introduced. Figure 13.2.2-2 was included to provide control effectiveness estimates for watered roads.

December 2003 – The public road emission factor equation (equation 1b) was adjusted to remove the component of particulate emissions from exhaust, brake wear, and tire wear. The parameter $C$ in the new equation varies with aerodynamic size range of the particulate matter. Table 13.2.2-4 was added to present the new coefficients.

January 2006 – The PM-2.5 particle size multipliers (i.e., factors) in Table 13.2.2-2 were modified and the quality ratings were upgraded from C to B based on the wind tunnel studies of a variety of dust emitting surface materials.

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## 13.2.4 Aggregate Handling And Storage Piles

### 13.2.4.1 General

Inherent in operations that use minerals in aggregate form is the maintenance of outdoor storage piles. Storage piles are usually left uncovered, partially because of the need for frequent material transfer into or out of storage.

Dust emissions occur at several points in the storage cycle, such as material loading onto the pile, disturbances by strong wind currents, and loadout from the pile. The movement of trucks and loading equipment in the storage pile area is also a substantial source of dust.

### 13.2.4.2 Emissions And Correction Parameters

The quantity of dust emissions from aggregate storage operations varies with the volume of aggregate passing through the storage cycle. Emissions also depend on 3 parameters of the condition of a particular storage pile: age of the pile, moisture content, and proportion of aggregate fines.

When freshly processed aggregate is loaded onto a storage pile, the potential for dust emissions is at a maximum. Fines are easily disaggregated and released to the atmosphere upon exposure to air currents, either from aggregate transfer itself or from high winds. As the aggregate pile weathers, however, potential for dust emissions is greatly reduced. Moisture causes aggregation and cementation of fines to the surfaces of larger particles. Any significant rainfall soaks the interior of the pile, and then the drying process is very slow.

Silt (particles equal to or less than 75 micrometers [µm] in diameter) content is determined by measuring the portion of dry aggregate material that passes through a 200-mesh screen, using ASTM-C-136 method.[1] Table 13.2.4-1 summarizes measured silt and moisture values for industrial aggregate materials.

Table 13.2.4-1. TYPICAL SILT AND MOISTURE CONTENTS OF MATERIALS AT VARIOUS INDUSTRIES[a]

| Industry | No. Of Facilities | Material | Silt Content (%) | | | Moisture Content (%) | | |
|---|---|---|---|---|---|---|---|---|
| | | | No. Of Samples | Range | Mean | No. Of Samples | Range | Mean |
| Iron and steel production | 9 | Pellet ore | 13 | 1.3 - 13 | 4.3 | 11 | 0.64 - 4.0 | 2.2 |
| | | Lump ore | 9 | 2.8 - 19 | 9.5 | 6 | 1.6 - 8.0 | 5.4 |
| | | Coal | 12 | 2.0 - 7.7 | 4.6 | 11 | 2.8 - 11 | 4.8 |
| | | Slag | 3 | 3.0 - 7.3 | 5.3 | 3 | 0.25 - 2.0 | 0.92 |
| | | Flue dust | 3 | 2.7 - 23 | 13 | 1 | — | 7 |
| | | Coke breeze | 2 | 4.4 - 5.4 | 4.9 | 2 | 6.4 - 9.2 | 7.8 |
| | | Blended ore | 1 | — | 15 | 1 | — | 6.6 |
| | | Sinter | 1 | — | 0.7 | 0 | — | — |
| | | Limestone | 3 | 0.4 - 2.3 | 1.0 | 2 | ND | 0.2 |
| Stone quarrying and processing | 2 | Crushed limestone | 2 | 1.3 - 1.9 | 1.6 | 2 | 0.3 - 1.1 | 0.7 |
| | | Various limestone products | 8 | 0.8 - 14 | 3.9 | 8 | 0.46 - 5.0 | 2.1 |
| Taconite mining and processing | 1 | Pellets | 9 | 2.2 - 5.4 | 3.4 | 7 | 0.05 - 2.0 | 0.9 |
| | | Tailings | 2 | ND | 11 | 1 | — | 0.4 |
| Western surface coal mining | 4 | Coal | 15 | 3.4 - 16 | 6.2 | 7 | 2.8 - 20 | 6.9 |
| | | Overburden | 15 | 3.8 - 15 | 7.5 | 0 | — | — |
| | | Exposed ground | 3 | 5.1 - 21 | 15 | 3 | 0.8 - 6.4 | 3.4 |
| Coal-fired power plant | 1 | Coal (as received) | 60 | 0.6 - 4.8 | 2.2 | 59 | 2.7 - 7.4 | 4.5 |
| Municipal solid waste landfills | 4 | Sand | 1 | — | 2.6 | 1 | — | 7.4 |
| | | Slag | 2 | 3.0 - 4.7 | 3.8 | 2 | 2.3 - 4.9 | 3.6 |
| | | Cover | 5 | 5.0 - 16 | 9.0 | 5 | 8.9 - 16 | 12 |
| | | Clay/dirt mix | 1 | — | 9.2 | 1 | — | 14 |
| | | Clay | 2 | 4.5 - 7.4 | 6.0 | 2 | 8.9 - 11 | 10 |
| | | Fly ash | 4 | 78 - 81 | 80 | 4 | 26 - 29 | 27 |
| | | Misc. fill materials | 1 | — | 12 | 1 | — | 11 |

[a] References 1-10. ND = no data.

## 13.2.4.3 Predictive Emission Factor Equations

Total dust emissions from aggregate storage piles result from several distinct source activities within the storage cycle:

1. Loading of aggregate onto storage piles (batch or continuous drop operations).
2. Equipment traffic in storage area.
3. Wind erosion of pile surfaces and ground areas around piles.
4. Loadout of aggregate for shipment or for return to the process stream (batch or continuous drop operations).

Either adding aggregate material to a storage pile or removing it usually involves dropping the material onto a receiving surface. Truck dumping on the pile or loading out from the pile to a truck with a front-end loader are examples of batch drop operations. Adding material to the pile by a conveyor stacker is an example of a continuous drop operation.

The quantity of particulate emissions generated by either type of drop operation, per kilogram (kg) (ton) of material transferred, may be estimated, with a rating of A, using the following empirical expression:[11]

$$E = k(0.0016)\ \frac{\left(\frac{U}{2.2}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}}\ \text{(kg/megagram [Mg])}$$

$$E = k(0.0032)\ \frac{\left(\frac{U}{5}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}}\ \text{(pound [lb]/ton)} \qquad (1)$$

where:

E = emission factor
k = particle size multiplier (dimensionless)
U = mean wind speed, meters per second (m/s) (miles per hour [mph])
M = material moisture content (%)

The particle size multiplier in the equation, k, varies with aerodynamic particle size range, as follows:

| Aerodynamic Particle Size Multiplier (k) For Equation 1 | | | | |
|---|---|---|---|---|
| < 30 μm | < 15 μm | < 10 μm | < 5 μm | < 2.5 μm |
| 0.74 | 0.48 | 0.35 | 0.20 | 0.053[a] |

[a] Multiplier for < 2.5 μm taken from Reference 14.

The equation retains the assigned quality rating if applied within the ranges of source conditions that were tested in developing the equation, as follows. Note that silt content is included, even though silt content does not appear as a correction parameter in the equation. While it is reasonable to expect that silt content and emission factors are interrelated, no significant correlation between the 2 was found during the derivation of the equation, probably because most tests with high silt contents were conducted under lower winds, and vice versa. It is recommended that estimates from the equation be reduced 1 quality rating level if the silt content used in a particular application falls outside the range given:

| Ranges Of Source Conditions For Equation 1 | | | |
|---|---|---|---|
| Silt Content (%) | Moisture Content (%) | Wind Speed | |
| | | m/s | mph |
| 0.44 - 19 | 0.25 - 4.8 | 0.6 - 6.7 | 1.3 - 15 |

To retain the quality rating of the equation when it is applied to a specific facility, reliable correction parameters must be determined for specific sources of interest. The field and laboratory procedures for aggregate sampling are given in Reference 3. In the event that site-specific values for correction parameters cannot be obtained, the appropriate mean from Table 13.2.4-1 may be used, but the quality rating of the equation is reduced by 1 letter.

For emissions from equipment traffic (trucks, front-end loaders, dozers, etc.) traveling between or on piles, it is recommended that the equations for vehicle traffic on unpaved surfaces be used (see Section 13.2.2). For vehicle travel between storage piles, the silt value(s) for the areas among the piles (which may differ from the silt values for the stored materials) should be used.

Worst-case emissions from storage pile areas occur under dry, windy conditions. Worst-case emissions from materials-handling operations may be calculated by substituting into the equation appropriate values for aggregate material moisture content and for anticipated wind speeds during the worst case averaging period, usually 24 hours. The treatment of dry conditions for Section 13.2.2, vehicle traffic, "Unpaved Roads", follows the methodology described in that section centering on parameter p. A separate set of nonclimatic correction parameters and source extent values corresponding to higher than normal storage pile activity also may be justified for the worst-case averaging period.

### 13.2.4.4 Controls[12-13]

Watering and the use of chemical wetting agents are the principal means for control of aggregate storage pile emissions. Enclosure or covering of inactive piles to reduce wind erosion can also reduce emissions. Watering is useful mainly to reduce emissions from vehicle traffic in the storage pile area. Watering of the storage piles themselves typically has only a very temporary slight effect on total emissions. A much more effective technique is to apply chemical agents (such as surfactants) that permit more extensive wetting. Continuous chemical treating of material loaded onto piles, coupled with watering or treatment of roadways, can reduce total particulate emissions from aggregate storage operations by up to 90 percent.[12]

### References For Section 13.2.4


1. C. Cowherd, Jr., *et al., Development Of Emission Factors For Fugitive Dust Sources*, EPA-450/3-74-037, U. S. Environmental Protection Agency, Research Triangle Park, NC, June 1974.

2. R. Bohn, *et al., Fugitive Emissions From Integrated Iron And Steel Plants*, EPA-600/2-78-050, U. S. Environmental Protection Agency, Cincinnati, OH, March 1978.

3. C. Cowherd, Jr., *et al., Iron And Steel Plant Open Dust Source Fugitive Emission Evaluation*, EPA-600/2-79-103, U. S. Environmental Protection Agency, Cincinnati, OH, May 1979.

4. *Evaluation Of Open Dust Sources In The Vicinity Of Buffalo, New York*, EPA Contract No. 68-02-2545, Midwest Research Institute, Kansas City, MO, March 1979.

5. C. Cowherd, Jr., and T. Cuscino, Jr., *Fugitive Emissions Evaluation*, MRI-4343-L, Midwest Research Institute, Kansas City, MO, February 1977.

6. T. Cuscino, Jr., *et al., Taconite Mining Fugitive Emissions Study*, Minnesota Pollution Control Agency, Roseville, MN, June 1979.

7. *Improved Emission Factors For Fugitive Dust From Western Surface Coal Mining Sources*, 2 Volumes, EPA Contract No. 68-03-2924, PEDCo Environmental, Kansas City, MO, and Midwest Research Institute, Kansas City, MO, July 1981.

8. *Determination Of Fugitive Coal Dust Emissions From Rotary Railcar Dumping*, TRC, Hartford, CT, May 1984.

9. *PM-10 Emission Inventory Of Landfills In the Lake Calumet Area*, EPA Contract No. 68-02-3891, Midwest Research Institute, Kansas City, MO, September 1987.

10. *Chicago Area Particulate Matter Emission Inventory — Sampling And Analysis*, EPA Contract No. 68-02-4395, Midwest Research Institute, Kansas City, MO, May 1988.

11. *Update Of Fugitive Dust Emission Factors In AP-42 Section 11.2*, EPA Contract No. 68-02-3891, Midwest Research Institute, Kansas City, MO, July 1987.

12. G. A. Jutze, *et al., Investigation Of Fugitive Dust Sources Emissions And Control*, EPA-450/3-74-036a, U. S. Environmental Protection Agency, Research Triangle Park, NC, June 1974.

13. C. Cowherd, Jr., *et al., Control Of Open Fugitive Dust Sources*, EPA-450/3-88-008, U. S. Environmental Protection Agency, Research Triangle Park, NC, September 1988.

14. C. Cowherd. *Background Document for Revisions to Fine Fraction Ratios &sed for AP-42 Fugitive Dust Emission Factors*. Prepared by Midwest Research Institute for Western Governors Association, Western Regional Air Partnership, Denver, CO, February 1, 2006.

## 13.5 Industrial Flares

### 13.5.1 General

Flaring is a high-temperature oxidation process used to burn combustible components, mostly hydrocarbons, of waste gases from industrial operations. Natural gas, propane, ethylene, propylene, butadiene and butane constitute over 95 percent of the waste gases flared. In combustion, gaseous hydrocarbons react with atmospheric oxygen to form carbon dioxide ($CO_2$) and water. In some waste gases, carbon monoxide (CO) is the major combustible component. Presented below, as an example, is the combustion reaction of propane.

$$C_3H_8 + 5\ O_2 \longrightarrow 3\ CO_2 + 4\ H_2O$$

During a combustion reaction, several intermediate products are formed, and eventually, most are converted to $CO_2$ and water. Some quantities of stable intermediate products such as carbon monoxide, hydrogen, and hydrocarbons will escape as emissions.

Flares are used extensively to dispose of (1) purged and wasted products from refineries, (2) unrecoverable gases emerging with oil from oil wells, (3) vented gases from blast furnaces, (4) unused gases from coke ovens, and (5) gaseous wastes from chemical industries. Gases flared from refineries, petroleum production, chemical industries, and to some extent, from coke ovens, are composed largely of low molecular weight hydrocarbons with high heating value. Blast furnace flare gases are largely of inert species and CO, with low heating value. Flares are also used for burning waste gases generated by sewage digesters, coal gasification, rocket engine testing, nuclear power plants with sodium/water heat exchangers, heavy water plants, and ammonia fertilizer plants.

There are two types of flares, elevated and ground flares. Elevated flares, the more common type, have larger capacities than ground flares. In elevated flares, a waste gas stream is fed through a stack anywhere from 10 to over 100 meters tall and is combusted at the tip of the stack. The flame is exposed to atmospheric disturbances such as wind and precipitation. In ground flares, combustion takes place at ground level. Ground flares vary in complexity, and they may consist either of conventional flare burners discharging horizontally with no enclosures or of multiple burners in refractory-lined steel enclosures.

The typical flare system consists of (1) a gas collection header and piping for collecting gases from processing units, (2) a knockout drum (disentrainment drum) to remove and store condensables and entrained liquids, (3) a proprietary seal, water seal, or purge gas supply to prevent flash-back, (4) a single- or multiple-burner unit and a flare stack, (5) gas pilots and an ignitor to ignite the mixture of waste gas and air, and, if required, (6) a provision for external momentum force (steam injection or forced air) for smokeless flaring. Natural gas, fuel gas, inert gas, or nitrogen can be used as purge gas. Figure 13.5-1 is a diagram of a typical steam-assisted elevated smokeless flare system.

Complete combustion requires sufficient combustion air and proper mixing of air and waste gas. Smoking may result from combustion, depending upon waste gas components and the quantity and distribution of combustion air. Waste gases containing methane, hydrogen, CO, and ammonia usually burn without smoke. Waste gases containing heavy hydrocarbons such as paraffins above methane, olefins, and aromatics, cause smoke. An external momentum force, such as steam injection or blowing air, is used for efficient air/waste gas mixing and turbulence, which promotes smokeless

Since flares do not lend themselves to conventional emission testing techniques, only a few attempts have been made to characterize flare emissions. Recent EPA tests using propylene as flare gas indicated that efficiencies of 98 percent can be achieved when burning an offgas with at least 11,200 $kJ/m^3$ (300 $Btu/ft^3$). The tests conducted on steam-assisted flares at velocities as low as 39.6 meters per minute (m/min) (130 ft/min) to 1140 m/min (3750 ft/min), and on air-assisted flares at velocities of 180 m/min (617 ft/min) to 3960 m/min (13,087 ft/min) indicated that variations in incoming gas flow rates have no effect on the combustion efficiency. Flare gases with less than 16,770 $kJ/m^3$ (450 $Btu/ft^3$) do not smoke.

Table 13.5-1 presents flare emission factors, and Table 13.5-2 presents emission composition data obtained from the EPA tests.[1] Crude propylene was used as flare gas during the tests. Methane was a major fraction of hydrocarbons in the flare emissions, and acetylene was the dominant intermediate hydrocarbon species. Many other reports on flares indicate that acetylene is always formed as a stable intermediate product. The acetylene formed in the combustion reactions may react further with hydrocarbon radicals to form polyacetylenes followed by polycyclic hydrocarbons.[2]

In flaring waste gases containing no nitrogen compounds, NO is formed either by the fixation of atmospheric nitrogen (N) with oxygen (O) or by the reaction between the hydrocarbon radicals present in the combustion products and atmospheric nitrogen, by way of the intermediate stages, HCN, CN, and OCN.[2] Sulfur compounds contained in a flare gas stream are converted to $SO_2$ when burned. The amount of $SO_2$ emitted depends directly on the quantity of sulfur in the flared gases.

Table 13.5-1 (English Units). EMISSION FACTORS FOR FLARE OPERATIONS[a]

EMISSION FACTOR RATING: B

| Component | Emission Factor ($lb/10^6$ Btu) |
|---|---|
| Total hydrocarbons[b] | 0.14 |
| Carbon monoxide | 0.37 |
| Nitrogen oxides | 0.068 |
| Soot[c] | 0 - 274 |

[a] Reference 1. Based on tests using crude propylene containing 80% propylene and 20% propane.
[b] Measured as methane equivalent.
[c] Soot in concentration values: nonsmoking flares, 0 micrograms per liter (μg/L); lightly smoking flares, 40 μg/L; average smoking flares, 177 μg/L; and heavily smoking flares, 274 μg/L.

Table 13.5-2. HYDROCARBON COMPOSITION OF FLARE EMISSION[a]

| Composition | Volume % | |
|---|---|---|
| | Average | Range |
| Methane | 55 | 14 - 83 |
| Ethane/Ethylene | 8 | 1 - 14 |
| Acetylene | 5 | 0.3 - 23 |
| Propane | 7 | 0 - 16 |
| Propylene | 25 | 1 - 65 |

[a] Reference 1. The composition presented is an average of a number of test results obtained under the following sets of test conditions: steam-assisted flare using high-Btu-content feed; steam-assisted using low-Btu-content feed; air-assisted flare using high-Btu-content feed; and air-assisted flare using low-Btu-content feed. In all tests, "waste" gas was a synthetic gas consisting of a mixture of propylene and propane.

References For Section 13.5


1. *Flare Efficiency Study*, EPA-600/2-83-052, U. S. Environmental Protection Agency, Cincinnati, OH, July 1983.

2. K. D. Siegel, *Degree Of Conversion Of Flare Gas In Refinery High Flares*, Dissertation, University of Karlsruhe, Karlsruhe, Germany, February 1980.

3. *Manual On Disposal Of Refinery Wastes, Volume On Atmospheric Emissions*, API Publication 931, American Petroleum Institute, Washington, DC, June 1977.

# APPENDIX F

# EMERGENCY ENGINE VENDOR DATA

CATERPILLAR®

# C18 ACERT™
# Fire Pump
**Tier 3**
**448 bkW/600 bhp @ 1750 rpm**

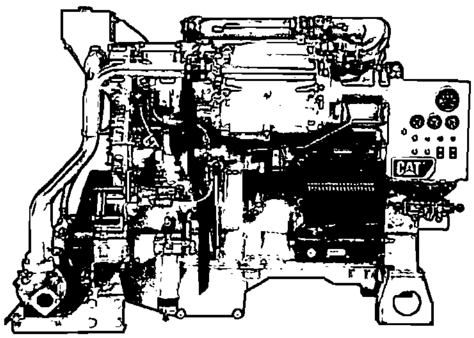


Image shown may not reflect actual engine

## CATERPILLAR ENGINE SPECIFICATIONS

**I-6, 4-Stroke-Cycle Diesel**

| | |
|---|---|
| Bore | 145.0 mm (5.71 in) |
| Stroke | 183.0 mm (7.2 in) |
| Displacement | 18.1 L (1,104.53 in3) |
| Aspiration | Turbocharged Aftercooled |
| Compression Ratio | 16.3:1 |
| Rotation (from flywheel end) | Counterclockwise |
| Weight, Net Dry (approximate) | 1769 kg (3900 lb) |

## FEATURES

### Emissions & Regulations
Meets U.S. EPA Tier 3 and CARB emissions requirements. FM approved. UL listed - US and Canada. Meets NFPA 20 requirements.

### Worldwide Supplier Capability
Caterpillar
- Casts engine blocks, heads, cylinder liners, and flywheel housings
- Machines critical components
- Assembles complete engine
- Factory-designed systems built at Caterpillar ISO 9001:2000 certified facilities

Ownership of these manufacturing processes enables Caterpillar to produce high quality, dependable product.

### Testing
Prototype testing on every model:
- proves computer design
- verifies system torsional stability
- functionality tests every model

Every Caterpillar engine is dynamometer tested under full load to ensure proper engine performance.

### Full Range of Attachments
Wide range of bolt-on system expansion attachments, factory designed and tested.

### Unmatched Product Support Offered Through Worldwide Caterpillar Dealer Network
More than 1,800 dealer outlets
Caterpillar factory-trained dealer technicians service every aspect of your industrial engine
99.7% of parts orders filled within 24 hours worldwide
Caterpillar parts and labor warranty
Preventive maintenance agreements available for repair before failure options

Scheduled Oil Sampling program matches your oil sample against Caterpillar set standards to determine:
- internal engine component condition
- presence of unwanted fluids
- presence of combustion by-products

### Web Site
For all your industrial power requirements, visit www.cat-industrial.com.

## STANDARD ENGINE EQUIPMENT

### Air Inlet System

Dual turbocharger: front and rear inlet, 127.0 mm (5.0 in)
Separate Circuit Aftercooled (SCAC)

### Charging System

Charging alternator 24 volt, 50 amp

### Control System

Dual Electronic Control Modules (ECMs) - primary and secondary
Electronic governing, PTO speed control
Programmable ratings
Cold mode start strategy
Automatic altitude compensation
Power compensation for fuel temperature
Programmable low and high idle and total engine limit (TEL)
Electronic diagnostics and fault logging
Engine monitoring and protection system (speeds, temperature, pressure)
J1939 Broadcast (diagnostic, engine status and control)

### Cooling System

Thermostats and housing, vertical outlet
Jacket water pump, gear driven, centrifugal
Heat exchanger (installed)
Expansion tank

### Exhaust System

Exhaust manifold, dry
Dual turbo: exhaust elbow, dry 203 mm (8 in)

### Flywheels and Flywheel Housing

Flywheel, SAE #1
Flywheel housing, SAE #1
SAE standard rotation

### Fuel System

Electronic unit injector
Fuel filter, secondary, mid-mount (LH 2 micron high performance)
Fuel transfer pump, LH front
Fuel priming pump, LH mid-mount
Fuel sample valve, mounted on fuel filter base
Primary filter / water separator

### Instrumentation

Instrument panel, LH
Engine oil pressure gauge
Voltmeter gauge
Water temperature gauge
Tachometer / engine hour meter

### Lube System

Crankcase breather, front valve cover
Oil cooler, RH (dual)
Oil filter, RH
Oil pan, front sump
Oil filler, LH front
Oil dipstick, LH front
Oil pump

### Mounting System

Front and rear support

### Power Take-Offs

Flywheel stub shaft

### Protection System

Stop-Start System, automatic (compatible with NFPA 20 requirements, able to be energized from either of two battery sources and capable of manual starter actuation)

### Starting System

24 volt, LH electric starting motor
Jacket water heater (3 kW, 120-240 volt)

### General

Vibration damper and guard
Paint, Caterpillar fire pump red
Lifting eyes
Automatic variable timing, electronic
Electronic installation kit, 70 pin connector (connectors, pins, sockets)
Literature, Owner and Operator's Manual

# PERFORMANCE CURVES

## IND - E - EM0068-00

Performance curve is not shown since fire pump technical data is published at constant speed (rpm).

Below data is shown from 100% load to 10% load.

| Engine Speed rpm | Engine Power kW | Torque N•m | BSFC g/kW-hr | Fuel Rate L/hr |
|---|---|---|---|---|
| 1750 | 448 | 2442 | 222.7 | 118.8 |
| 1750 | 403 | 2198 | 225.4 | 108.2 |
| 1750 | 358 | 1954 | 227.1 | 96.9 |
| 1750 | 336 | 1831 | 228.2 | 91.3 |
| 1750 | 313 | 1709 | 230.3 | 86.0 |
| 1750 | 45 | 244 | 327.9 | 17.5 |
| 1750 | 224 | 1221 | 242.7 | 64.7 |
| 1750 | 179 | 977 | 240.1 | 51.2 |
| 1750 | 134 | 733 | 236 | 37.8 |
| 1750 | 112 | 610 | 232.6 | 31.0 |
| 1750 | 90 | 488 | 243.1 | 25.9 |
| 1750 | 269 | 1465 | 235.5 | 75.4 |

## PERFORMANCE CURVES

**IND - E - EM0068-00**

Performance curve is not shown since fire pump technical data is published at constant speed (rpm).

Below data is shown from 100% load to 10% load.

| Engine Speed rpm | Engine Power bhp | Engine Torque lb•ft | BSFC lb/bhp-hr | Fuel Rate gal/hr |
|---|---|---|---|---|
| 1750 | 600 | 1801 | .366 | 31.4 |
| 1750 | 540 | 1621 | .371 | 28.6 |
| 1750 | 480 | 1441 | .373 | 25.6 |
| 1750 | 450 | 1350 | .375 | 24.1 |
| 1750 | 420 | 1260 | .379 | 22.7 |
| 1750 | 60 | 180 | .539 | 4.6 |
| 1750 | 300 | 901 | .399 | 17.1 |
| 1750 | 240 | 721 | .395 | 13.5 |
| 1750 | 180 | 541 | .388 | 10.0 |
| 1750 | 150 | 450 | .382 | 8.2 |
| 1750 | 120 | 360 | .400 | 6.8 |
| 1750 | 360 | 1081 | .387 | 19.9 |

**CATERPILLAR®**

# C18 ACERT™ Fire Pump

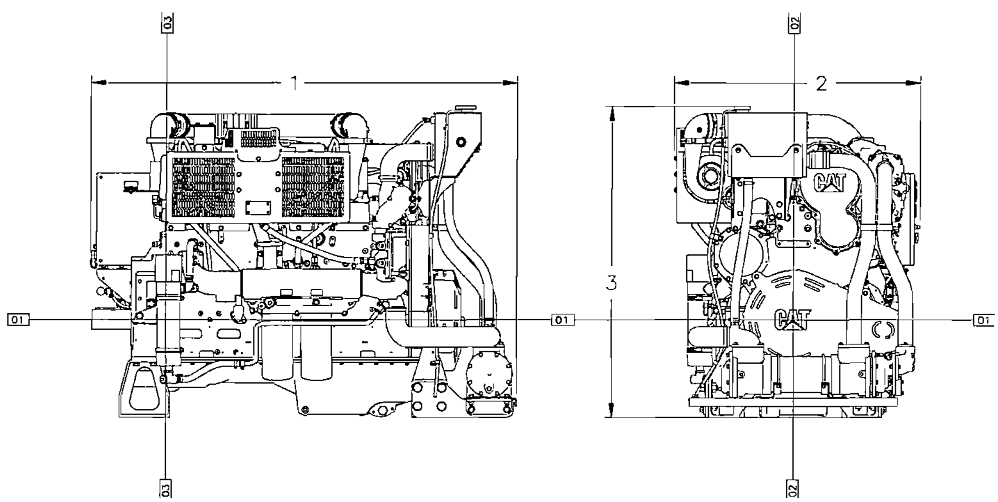
**Tier 3**

## RATINGS AND CONDITIONS

**448 bkW/600 bhp @ 1750 rpm**

**Standby Fire Pump** Ratings represent the output which may be utilized to drive stationary fire pumps where the pumping equipment has been sized according to NFPA 20 standards. Engine rating is FM approved and UL listed (US and Canada).

**Engine Performance** Diesel Engines — 7 liter and higher
All rating conditions are based on SAE J1995, inlet air standard conditions of 99 kPa (29.31 in. Hg) dry barometer and 25°C (77°F) temperature. Performance measured using a standard fuel with fuel gravity of 35° API having a lower heating value of 42,780 kJ/kg (18,390 btu/lb)when used at 29° C (84.2° F) with a density of 838.9 g/L.




| Engine Dimensions | |
|---|---|
| (1) Length | 1889.0 mm (74.37 in) |
| (2) Width | 1091.0 mm (42.95 in) |
| (3) Height | 1379.7 mm (54.32 in) |

Note: Do not use for installation design. See general dimension drawings for detail (Drawing # null ).

Performance Number: EM0068-00

Feature Code: C18DF01 Arr. Number: 3311789

Materials and specifications are subject to change without notice.

15476131



The International System of Units (SI) is used in this publication.

# DIESEL GENERATOR SET

CATERPILLAR®

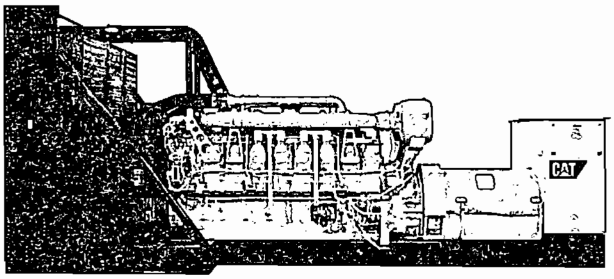


Image shown may not reflect actual package.

# STANDBY
## 2000 ekW 2500 kVA
## 60 Hz 1800 rpm 12 470 Volts

**Caterpillar is leading the power generation marketplace with Power Solutions engineered to deliver unmatched flexibility, expandability, reliability, and cost-effectiveness.**

## FEATURES

**FUEL/EMISSIONS STRATEGY**
- EPA Tier 2

**DESIGN CRITERIA**
- The generator set accepts 100% rated load in one step per NFPA 110 and meets ISO 8528-5 transient response.

**FULL RANGE OF ATTACHMENTS**
- Wide range of bolt-on system expansion attachments, factory designed and tested

**SINGLE-SOURCE SUPPLIER**
- Fully prototype tested with certified torsional vibration analysis available

**WORLDWIDE PRODUCT SUPPORT**
- Caterpillar® dealers provide extensive post sale support including maintenance and repair agreements
- Caterpillar dealers have over 1,600 dealer branch stores operating in 200 countries
- The Cat® S•O•S℠ program cost effectively detects internal engine component condition, even the presence of unwanted fluids and combustion by-products

**CAT 3516C TA DIESEL ENGINE**
- Reliable, rugged, durable design
- Field-proven in thousands of applications worldwide
- Four-stroke-cycle diesel engine combines consistent performance and excellent fuel economy with minimum weight

**CAT SR4B HV GENERATOR**
- Matched to the performance and output characteristics of Caterpillar engines
- Single point access to accessory connections
- UL 1446 Recognized Class F insulation

**CAT EMCP 3 SERIES CONTROL PANELS**
- Simple user friendly interface and navigation
- Scalable system to meet a wide range of customer needs
- Integrated Control System and Communications Gateway

## FACTORY INSTALLED STANDARD & OPTIONAL EQUIPMENT

| System | Standard | Optional |
|---|---|---|
| Air Inlet | • Single element canister type air cleaner<br>• Service indicator | • Dual element & heavy duty air cleaners (with pre-cleaners)<br>• Air inlet adapters & shutoff |
| Cooling | • Radiator with guard (43°C)<br>• Coolant drain line with valve<br>• Fan and belt guards<br>• Caterpillar Extended Life Coolant<br>• Low coolant level & high temperature alarm or shutdown | • Radiator duct flange<br>• Jacket water heater |
| Exhaust | • Dry exhaust manifold<br>• Flanged faced outlets | • Mufflers and Silencers<br>• Stainless steel exhaust flex fittings<br>• Elbows, flanges, expanders & Y adapters |
| Fuel | • Secondary fuel filters<br>• Fuel priming pump<br>• Flexible fuel lines<br>• Fuel cooler*<br>*Not included with packages without radiators | • Water separator<br>• Duplex fuel filter |
| Generator SR4B HV | • Class F insulation<br>• Class H temperature (125°C prime/150°C standby)<br>• Anti-condensation space heater<br>• Bearing temperature detector<br>• Stator temperature detector | • Oversize & premium generators |
| Power Termination | • Bus bar (NEMA and IEC meachanicallug holes) -right side standard<br>• Top and bottom cable entry | • Circuit breakers, UL listed, 3 pole with shunt trip, 80% or 100% rated, choice of trip units, manual or electrically operated (low voltage only)<br>• Circuit breakers, IEC compliant, 3 or 4 pole with shunt trip (low voltage only), choice of trip units, manual or electrically operated<br>• Shroud cover for bottom cable entry<br>• Power terminations can be located on the left and/or rear as an option. Also, multiple circuit breakers can be ordered (up to 3) |
| Governor | • ADEM™ 3 | • Load share module |
| Control Panels | • User Interface panel (UIP) - rear mount (standard)<br>• EMCP3.1 Genset Controller<br>• Speed adjust (on panel)<br>• AC&DC customer wiring area (right side)<br>• CAT digital voltage regulator (CDVR) with KVAR/PF control, 3-phase sensing<br>• Emergency Stop Pushbutton | • EMCP 3.3<br>• Option for right or left mount UIP<br>• Local & remote annunciator modules<br>• Load share module<br>• Discrete I/O module<br>• Generator temperature monitoring & protection<br>• Voltage Adjust (on panel) |
| Lube | • Lubricating oil and filter<br>• Oil drain line with valves<br>• Fumes disposal | • Sump pump (manual)<br>• Sump & prelube pump (manual or electric)<br>• Oil level regulator |
| Mounting | • Structual steel tube<br>• Anti-vibration mounts (shipped loose) | • Isolator removal |
| Starting/Charging | • 24 volt starting motor(s)<br>• Batteries with rack and cables<br>• Battery disconnect switch | • Battery chargers (10&20AMP)<br>•45 amp charging alternator<br>• Oversize batteries<br>• Ether starting aid<br>• Heavy duty starting motors<br>• Barring device (manual)<br>• Air starting motor with control & silencer |
| General | • Right-hand service<br>• Paint - Caterpillar Yellow except rails and radiators are gloss black<br>• SAE standard rotation<br>• Flywheel and flywheel housing - SAE No. 00 | • CSA certification<br>• EU Certificate of Conformance |
| Note | Standard and optional equipment may vary for UL 2200 Listed Packages. UL 2200 Listed packages may have oversized generators with a different temperature rise and motor starting characteristics. | |

# STANDBY 2000 ekW 2500 kVA

**60 Hz 1800 rpm 12 470 Volts**

CATERPILLAR®

## SPECIFICATIONS

### CAT GENERATOR

Frame............................................................................2750
Excitation............................................... Permanent Magnet
Pitch.......................................................................... 0.6670
Number of poles...................................................................4
Number of bearings............................................................ 2
Number of leads...................................................................6
Insulation..... Class H with tropicalization and antiabrasion
IP Rating.......................................................Drip Proof IP22
Alignment...................................................Closed Coupled
Overspeed capability................................................... 125%
Wave form.......................................................................... 2%
Paralleling kit/Droop transformer.........................Standard
Voltage regulator..................3 Phase sensing with volts/Hz
Voltage regulation ...........Less than +/- 1/2% (steady state)
Less than +/- 1/2% (w/3% speed change)
Telephone influence factor..............................Less than 50
Harmonic distortion........................................ Less than 5%

### CAT DIESEL ENGINE

3516C ATAAC V-16, 4 Stroke, water-cooled diesel
Bore........................................................ 170.00 mm (6.69 in)
Stroke..................................................... 190.00 mm (7.48 in)
Displacement.........................................69.00 L (4210.64 $in^3$)
Compression Ratio...................................................... 14.7:1
Aspiration............................................................................TA
Fuel System.................................... Electronic unit injection
Governor Type..........................................................ADEM3

### CAT EMCP3 CONTROL PANELS

EMCP 3.1 (standard)
EMCP 3.2 & 3.3 (Optional)
24 Volt DC control
Generator insturments designed to meet UL/CSA/CE
Integral generator terminal box
Single location for customer connection
MODBUS isolated data link (RS0485 half-duplex)
supports serial communication at data rate up to 33.6 kbaud
Auto start/stop control
True RMS metering, 3-phase
• Digital indication for:
-RPM
-Operating hours
-Oil pressure
-Coolant temperature
- System DC volts
--L-L volts, L-N volts, phase amps, Hz
-Ekw, kVA, kVAR, kW-hr, %kW, PF
• Shutdowns with indicating lights for:
-Low oil pressure
-High coolant temperature
- Low coolant level
- Overspeed
-Overspeed
-Emergency stop
- Failure to start (over crank)
• Programmable protective relay functions:
- Under and over voltage
- Under and over frequency
- Reverse power
- Overcurrent (phase & total)
-

## TECHNICAL DATA

| Open Generator Set - - 1800 rpm/60 Hz/12 470 Volts | DM8263 | |
|---|---|---|
| **EPA Tier 2** | | |
| **Generator Set Package Performance** | | |
| Genset Power rating @ 0.8 pf | 2500 kVA | |
| Genset Power rating with fan | 2000 ekW | |
| **Coolant to aftercooler** | | |
| Coolant to aftercooler temp max | 50 ° C | 122 ° F |
| **Fuel Consumption** | | |
| 100% load with fan | 525.7 L/hr | 138.9 Gal/hr |
| 75% load with fan | 408.2 L/hr | 107.8 Gal/hr |
| 50% load with fan | 294.2 L/hr | 77.7 Gal/hr |
| **Cooling System**[1] | | |
| Air flow restriction (system) | 0.12 kPa | 0.48 in. water |
| Air flow (max @ rated speed for radiator arrangement) | 2480 $m^3$/min | 87580 cfm |
| Engine Coolant capacity with radiator/exp. tank | 475.0 L | 125.5 gal |
| Engine coolant capacity | 233.0 L | 61.6 gal |
| Radiator coolant capacity | 242.0 L | 63.9 gal |
| **Inlet Air** | | |
| Combustion air inlet flow rate | 180.3 $m^3$/min | 6367.2 cfm |
| **Exhaust System** | | |
| Exhaust stack gas temperature | 405.4 ° C | 761.7 ° F |
| Exhaust gas flow rate | 428.6 $m^3$/min | 15135.9 cfm |
| Exhaust flange size (internal diameter) | 203.2 mm | 8.0 in |
| Exhaust system backpressure (maximum allowable) | 6.7 kPa | 26.9 in. water |
| **Heat Rejection** | | |
| Heat rejection to coolant (total) | 765 kW | 43505 Btu/min |
| Heat rejection to exhaust (total) | 1804 kW | 102593 Btu/min |
| Heat rejection to aftercooler | 666 kW | 37875 Btu/min |
| Heat rejection to atmosphere from engine | 137 kW | 7791 Btu/min |
| Heat rejection to atmosphere from generator | 89.9 kW | 5112.6 Btu/min |
| **Alternator**[2] | | |
| Motor starting capability @ 30% voltage dip | 3509 skVA | |
| Frame | 2750 | |
| Temperature Rise | 130 ° C | 234 ° F |
| **Lube System** | | |
| Sump refill with filter | 401.3 L | 106.0 gal |
| **Emissions (Nominal)**[3] | | |
| NOx g/hp-hr | 5.39 g/hp-hr | |
| CO g/hp-hr | .29 g/hp-hr | |
| HC g/hp-hr | .11 g/hp-hr | |
| PM g/hp-hr | .026 g/hp-hr | |

[1] For ambient and altitude capabilities consult your Caterpillar dealer. Air flow restriction (system) is added to existing restriction from factory.
[2] UL 2200 Listed packages may have oversized generators with a different temperature rise and motor starting characteristics. Generator temperature rise is based on a 40 degree C ambient per NEMA MG1-32.
[3] Emissions data measurement procedures are consistent with those described in EPA CFR 40 Part 89, Subpart D & E and ISO8178-1 for measuring HC, CO, PM, NOx. Data shown is based on steady state operating conditions of 77°F, 28.42 in HG and number 2 diesel fuel with 35° API and LHV of 18,390 btu/lb. The nominal emissions data shown is subject to instrumentation, measurement, facility and engine to engine variations. Emissions data is based on 100% load and thus cannot be used to compare to EPA regulations which use values based on a weighted cycle.

## RATING DEFINITIONS AND CONDITIONS

**Meets or Exceeds International Specifications:** AS1359, CSA, IEC60034, ISO 3046, ISO 8528, NEMA MG 1-33, UL508A, 98/37/EC

**Standby** - Output available with varying load for the duration of the interruption of the normal source power. Average power output is 70% of the standby power rating. Typical operation is 200 hours per year, with maximum expected usage of 500 hours per year. Standby power in accordance with ISO 8528. Fuel stop power in accordance with ISO 3046. Standby ambients shown indicate ambient temperature at 100% load which results in a coolant top tank temperature just below the shutdown temperature.

**Ratings** are based on SAE J1349 standard conditions. These ratings also apply at ISO 3046 standard conditions.

**Fuel rates** are based on fuel oil of 35° API [16° C (60° F)] gravity having an LHV of 42 780 kJ/kg (18,390 Btu/lb) when used at 29° C (85° F) and weighing 838.9 g/liter (7.001 lbs/U.S. gal.). Additional ratings may be available for specific customer requirements, contact your Caterpillar representative for details. For information regarding Low Sulfur fuel and Biodiesel capability, please consult your Caterpillar dealer.

CATERPILLAR®

## DIMENSIONS

| Package Dimensions | | |
|---|---|---|
| **Length** | **6890.3 mm** | **271.27 in** |
| **Width** | **2378.1 mm** | **93.63 in** |
| **Height** | **2953.3 mm** | **116.27 in** |
| **Weight** | **19 127 kg** | **42,168 lb** |

NOTE: For reference only - do not use for installation design. Please contact your local dealer for exact weight and dimensions. (General Dimension Drawing #2846049).

Performance No.: DM8263

Feature Code: 516DE5B

Gen. Arr. Number: 2524232

Source: U.S. Sourced

www.CAT-ElectricPower.com



Materials and specifications are subject to change without notice.
The International System of Units (SI) is used in this publication.

APPENDIX G

PRELIMINARY LEAK DETECTION AND REPAIR PROGRAM
FOR HIGHLANDS ENVIROFUELS, LLC
HIGHLANDS COUNTY, FLORIDA
MAY 2011

# APPENDIX G

# PRELIMINARY LEAK DETECTION AND REPAIR PROGRAM FOR HIGHLANDS ENVIROFUELS, LLC HIGHLANDS COUNTY, FLORIDA MAY 2011

## 1.0 INTRODUCTION

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

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

For the proposed HEF facility, Subpart VVa would apply to the ethanol production process, storage tanks, and the ethanol truck loading rack. In order to comply with the leak detection and repair requirements of Subpart VVa, a leak detection and repair (LDAR) program must be developed and implemented. HEF must be in compliance with Subpart VVA, including the LDAR program, no later than 180 days after the HEF facility becomes operational.

The following presents the framework for establishing a LDAR program at the HEF facility. The use of this procedure will assure compliance with federal and state regulations. This procedure applies to all regulated equipment used in volatile organic compound (VOC) service within the ethanol production process at the HEF Biorefinery.

# 2.0 LDAR PROGRAM

## 2.1 Identification of Process Equipment

- Identify each regulated piece of equipment component, the type of equipment, and type of service. Document in a log.
- Assign a unique identification (ID) number to each piece of equipment. Update as necessary.
- Tag and physically locate each piece of equipment in the facility. Verify its location on the piping and instrumentation diagrams (P&IDs) or process flow diagrams. Update as necessary.
- Maintain log of dates when new equipment is added and replacement equipment is taken out of service.

## 2.2 Leak Definition

- Identify the definition of "leaking" for each piece of equipment. Leak definitions vary by equipment type, VOC service (e.g., light liquid, heavy liquid, gas/vapor), and monitoring frequency. The regulations may define a leak based on a measured VOC level, visual inspections and observations (such as fluids dripping, spraying, misting, or clouding around equipment), sound (such as hissing), or smell.

## 2.3 Monitoring of Equipment

- Identify the monitoring frequency for each piece of equipment. Monitoring frequency may be weekly, monthly, quarterly, or annually. Document equipment and frequency in a log.
- Monitor all regulated equipment in accordance with U.S. Environmental Protection Agency (EPA) Method 21, contained in 40 CFR 60 Appendix A, which measures VOC emissions. Attach ID tags to all leaking equipment.
- Obtain background VOC readings from equipment designated as "no detectable emissions" initially, annually, and when requested by the Florida Department of Environmental Protection (FDEP). Record date of monitoring and instrument reading.

## 2.4 Repairing of Equipment

- Repair all leaking components as soon as practicable, but no later than the time period specified in the rule for each type of equipment (generally between 5 and 15 days for first attempt at repair).
- Test the repaired equipment per Method 21 to ensure the equipment 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.

## 2.5 Recordkeeping

- Maintain a list of ID numbers for all equipment subject to Subpart VVa.
- Maintain a list of ID numbers for all equipment designated as "no detectable leaks."
- Maintain a list of ID numbers for all valves designated as "unsafe to monitor," and an explanation/review of conditions for the designation.

- Maintain the results of performance testing and leak detection monitoring, including leak monitoring results per the leak frequency, monitoring no-leak equipment, and non-periodic event monitoring.
- For all detected leaks, maintain records of the equipment ID number, the instrument and operator ID numbers, and the date the leak was detected.
- Maintain a log of the dates of each repair attempt and an explanation of the attempted repair method.
- Maintain a log of the dates of successful repairs. Document results of monitoring test to demonstrate the leak was repaired successfully.

# APPENDIX H

# ALTERNATIVE MONITORING PROCEDURE FOR OPACITY

# APPENDIX H
# ALTERNATIVE OPACITY MONITORING PLAN FOR BIOMASS BOILER
# HIGHLANDS ENVIROFUELS, LLC

Highlands EviroFuels, LLC (HEF) proposes the following alternative monitoring plan (AMP) for opacity when the Biomass Boiler is firing biomass or natural gas. This plan is consistent with AMPs for other similar biomass boilers. The Biomass Boiler will be subject to particulate matter (PM) and opacity limits.

Firing wood in the Boiler subjects the boiler to the opacity standard under Title 40, Part 60 of the Code of Federal Regulations (40 CFR 60), Subpart Db, along with the requirement to install and operate a continuous opacity monitoring system (COMS). The opacity standard is contained in §60.43b(f), and is 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Section §60.48b(a) further provides that any affected facility subject to an opacity standard under 60.43b shall install a COMS.

Wood firing in the Boiler subjects the Boiler to the applicable PM emission limit under Subpart Db, which is 0.03 pound per million British thermal units (lb/MMBtu). However, a PM limit of 0.015 lb/MMBtu is the proposed best available control technology (BACT) limit for the Boiler.

The Biomass Boiler will be equipped with wet cyclone (sand separator) ahead of the electrostatic precipitator (ESP) control device. The wet sand separator is necessary to remove abrasive sand from the flue gas prior to the ESP and induced draft (ID) fan. A significant amount of water [up to 700 gallons per minute (gpm)] is injected into the flue gas stream passing through the sand separator. For this reason, a COMS placed in the Boiler stack may not provide accurate measurements due to liquid water interference.

The effectiveness of the ESP in controlling PM emissions from the Boiler can be evaluated based on total power input to the ESP. The ESP will have a total of four fields. Total power input can be determined by monitoring secondary voltage and secondary current to each field, calculating power input to each field, and summing the individual field values to obtain total secondary power input.

Total secondary power input to the ESP is a recognized parameter for controlling emissions of PM and PM less than 10 microns ($PM_{10}$). Once the Boiler is operational, HEF will develop test data for PM emissions while firing both bagasse and wood in the Boiler, and will use the test data to establish an indicator value for total secondary power input to the ESP for bagasse and wood chip firing. The test data correlating the parameter to the PM emission levels will be presented in the Compliance Assurance Monitoring (CAM) Plan for the Boiler.

The proposed parameter minimum value will be based on 90 percent of the minimum parameter value recorded during any test run from the PM testing, when compliance was demonstrated with the PM/$PM_{10}$ limit. ESP operating parameter values below this minimum parameter value will be indicative of abnormal operation of the control device. This methodology is consistent with the establishment of ESP operating limits under 40 CFR 63, Subpart DDDDD, which are the Industrial Boiler/Process Heater Maximum Available Control Technology (MACT) standards (the rule has now been vacated).

The CAM regulations generally require that pollutant-specific emissions units with the potential to emit greater than 100 tons per year (TPY) collect monitoring data at least four times per hour. The CAM regulations also state that emission units with controlled emissions less than 100 TPY are subject to a reduced data collection frequency of at least once per day [40 CFR 64.3(b)(4)(iii)]. Although the Boiler has controlled emissions of less than 100 TPY, HEF proposes to continuously record total ESP secondary power input and to calculate a 3-hour block average.

Based on collecting data continuously and calculating 3-hour block averages, an excursion will occur whenever any 3-hour block average of total secondary power input is below the minimum parameter value. When an excursion occurs, corrective action will be initiated, beginning with an evaluation of the occurrence, to determine the action required (if any) to correct the situation. All excursions will be documented and reported on a semi-annual basis.

The AMP for opacity when firing bagasse and wood chips is summarized below for the Biomass Boiler.

## Monitoring Approach

The monitoring approach is based on monitoring total ESP secondary power input, which is calculated from the ESP secondary voltage and secondary current. The monitoring approach is summarized in the table below.

| Boiler No. 8 | Indicator No. 1 |
|---|---|
| Indicator | Total ESP Secondary Power Input |
| Measurement Approach | Whenever biomass is fired in the Boiler, total secondary power input to each field is calculated from the secondary current and voltage, which are monitored with an amp/volt meter. |
| Indicator Range | An excursion is defined as any total power input below ____ kilowatts (kW). Excursions trigger an inspection, corrective action, and a recordkeeping and reporting requirement. |
| Data Representativeness | Accuracy of the amp/volt meter is ±1 milliampere (mA) and ±1 kilovolt (kV). |
| Verification of Operational Status | NA |
| Quality Assurance/ Quality Control (QA/QC) Practices and Criteria | The amp/volt meter is maintained in accordance with the manufacturer's recommendations. |
| Monitoring Frequency | ESP secondary current and secondary voltage are measured continuously and used to determine the total secondary power input. |
| Data Collection Procedures | Total power input calculated from voltage and current readings taken continuously for each field of the ESP. |
| Averaging Period | Calculation of a 3-hour block average of total power input. |

# APPENDIX I

## BEST MANAGEMENT PRACTICES (BMP) PLAN FOR
## MINIMIZATION OF FUGITIVE DUST, PILE MANAGEMENT, AND FIRE PREVENTION
## HIGHLANDS ENVIROFUELS, LLC
## HIGHLANDS COUNTY, FLORIDA
## MAY 2011

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

## Highlands EnviroFuels, LLC
## Highlands County, FL

| | |
|---|---|
| Best Management Practices – Minimization of Fugitive Dust | 1) Conveyor systems and associated drop points shall be enclosed or partially enclosed.<br>2) Drop points to supplemental biomass storage areas shall be designed to minimize the overall exposed (or exposed to atmosphere) drop height.<br>3) Periodic equipment maintenance shall be performed to maintain conveyor systems and associated drop point integrity. Appropriate plant records shall be maintained on equipment maintenance performed.<br>4) Daily observations of the conveyor systems and associated drop point integrity to identify any equipment abnormalities.<br>5) Plant personnel shall be trained on identification of warning signs for potential equipment malfunction.<br>6) Signs shall be posted identifying potential warning signs of equipment malfunction.<br>7) Procedures shall be established for defining excessive fugitive dust from biomass truck unloading operations. Plant personnel shall visually observe truck unloading operations and if excessive fugitive dust is detected appropriate fugitive dust minimization techniques shall be implemented. Plant personnel shall be trained on procedures for defining and minimizing excessive dust from the truck unloading operations.<br>8) All major roadways at the plant shall be paved.<br>9) Plant gravel areas shall be wetted during dry conditions, as required, to minimize fugitive dust emissions.<br>10) Mud, dirt or similar debris shall be removed promptly from the paved roads by vacuum sweeping or watering.<br>11) Plant personnel shall be trained on recognizing conditions of excessive dust on paved roads.<br>12) All silos shall be equipped with vent filters. |
| Storage Pile Management | 1) Supplemental biomass storage areas shall be managed to avoid excessive wind erosion.<br>2) A biomass fugitive dust management plan shall be developed and maintained onsite. Plan shall identify warning signs for conditions that could result in excessive fugitive dust formation. Plant personnel shall be trained on warning signs of excessive fugitive dust.<br>3) Mechanical moving of supplemental biomass by front end loaders and other supporting equipment shall be minimized on high wind event days.<br>4) Odors are minimized with first in, first out supplemental biomass utilization implemented.<br>5) Daily visual observations of the supplemental biomass storage areas shall be performed, and if conditions are favorable for fugitive dust formation, procedures from the fugitive dust plan shall be implemented. |

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

# APPENDIX J

# CONTROL EQUIPMENT VENDOR DATA

## Table J-1: Cost of SNCR System for HEF Bagasse Boiler

| Cost Items | Cost Factors[a] | 0.10 lb/MMBtu/ 10 ppmvd NH3 ($) |
|---|---|---|
| DIRECT CAPITAL COSTS (DCC): | | |
| Purchased Equipment Cost (PEC) | | |
| Control Equipment and Materials | Vendor Quote - SNCR[b] | 800,000 |
| Urea Storage Tank | Vendor quote | Included |
| Miscellaneous | Estimate-10% of vendor quote | 80,000 |
| Total-Control Equipment and Materials | | 880,000 |
| Control System/Emissions Monitoring | 15% of equipment cost | 132,000 |
| Foundation and Structure Support | 8% of equipment cost | 70,400 |
| Freight | 5% of equipment cost | 44,000 |
| Taxes | Florida sales tax, exempt | 0 |
| Total PEC: | | 1,126,400 |
| Direct installation | 60% of vendor supplied equipment | 528,000 |
| Total DCC: | | 1,654,400 |
| INDIRECT CAPITAL COSTS (ICC): | | |
| General Facilities | 5% of DCC | 82,720 |
| Eng. and Home Office Fees | 10% of DCC | 165,440 |
| Process Contingencies | 5% of DCC | 82,720 |
| Total ICC: | | 330,880 |
| PROJECT CONTINGENCY | 15% of (DCC + ICC) | 0 |
| TOTAL CAPITAL INVESTMENT (TCI): | DCC + ICC | 1,985,280 |
| DIRECT OPERATING COSTS (DOC): | | |
| (1) Maintenance | 1.5% of TCI | 29,779 |
| (2) Electricity | 36 kW; $0.060/kW-hr | 17,107 |
| (3) Anhydrous Ammonia Cost (19%) | 35 gal/hr, $8.00/gal NH3, 7,920 hr/yr | 421,344 |
| Total DOC: | | 468,230 |
| INDIRECT OPERATING COSTS (IOC): | | |
| Overhead | 0% of total capital investment | 0 |
| Property Taxes | 0% of total capital investment | 0 |
| Insurance | 0% of total capital investment | 0 |
| Administration | 0% of total capital investment | 0 |
| Total IOC: | | 0 |
| CAPITAL RECOVERY COSTS (CRC): | CRF of 0.0944 times TCI (20 yrs @ 7%) | 187,410 |
| ANNUALIZED COSTS (AC): | DOC + IOC + CRC | 655,641 |

Footnotes:
[a] Unless otherwise specified, factors and cost estimates reflect OAQPS Cost Manual, Section 3, Sixth edition.
[b] 2010 proposal for similar facility.

## Table J-2: Cost of DSI/ESP System for HEF Bagasse Boiler

| Cost Items | | Cost Factors[a] | DSI/ESP ($) |
|---|---|---|---|
| DIRECT CAPITAL COSTS (DCC): | | | |
| | Purchased Equipment Cost (PEC) | | |
| | Control Equipment and Materials | Vendor Quote - IDSIS/ESP[b] | 3,000,000 |
| | Hopper Conveyors and Airlocks | Estimate | 100,000 |
| | Lime/Trona Silo | Estimate | 200,000 |
| | Miscellaneous | Estimate | 230,000 |
| | Total-Purchased Equipment | | 3,530,000 |
| | Emissions Monitoring | 10% of equipment cost | 353,000 |
| | Foundation and Structure Support | 8% of equipment cost | 282,400 |
| | Freight | Vendor quote[b] | 550,000 |
| | Taxes | Florida sales tax, exempt | 0 |
| Total PEC: | | | 4,715,400 |
| | Direct installation | Vendor quote/estimate | 500,000 |
| Total DCC: | | | 5,215,400 |
| INDIRECT CAPITAL COSTS (ICC): | | | |
| | General Facilities | 5% of DCC | 260,770 |
| | Eng. And home Office Fees | 10% of DCC | 521,540 |
| | Process Contingencies | 5% of DCC | 260,770 |
| Total ICC: | | | 1,043,080 |
| PROJECT CONTINGENCY | | 15% of (DCC + ICC) | 0 |
| TOTAL CAPITAL INVESTMENT (TCI): | | DCC + ICC | 6,258,480 |
| DIRECT OPERATING COSTS (DOC): | | | |
| (1) | Maintenance | 1.5% of TCI | 93,877 |
| (2) | Electricity | 175 hp = 130 kW; $0.060/kW-hr | 62,712 |
| (4) | Trona for DSI | 316 lb/hr; $165/ton | 209,603 |
| (5) | ESP Power Cost | 243 kw; $60/MWh | 117,223 |
| Total DOC: | | | 483,415 |
| INDIRECT OPERATING COSTS (IOC): | | | |
| | Overhead | 0% of total capital investment | 0 |
| | Property Taxes | 0% of total capital investment | 0 |
| | Insurance | 0% of total capital investment | 0 |
| | Administration | 0% of total capital investment | 0 |
| Total IOC: | | | 0 |
| CAPITAL RECOVERY COSTS (CRC): | | CRF of 0.0944 times TCI (20 yrs @ 7%) | 590,801 |
| ANNUALIZED COSTS (AC): | | DOC + IOC + CRC | 1,074,216 |

Footnotes:
[a] Unless otherwise specified, factors and cost estimates reflect OAQPS Cost Manual, Section 3, Sixth edition.
[b] Proposal for HEF dated May 2011.

**Table J-3: Cost of DSI/ESP/SCR System for HEF Bagasse Boiler**

| Cost Items | Cost Factors[a] | Suspension/Grate Boiler (w/o Ox-Cat) ($) | Suspension/Grate Boiler (w/Ox-Cat) ($) |
|---|---|---|---|
| DIRECT CAPITAL COSTS (DCC): | | | |
| Purchased Equipment Costs (PEC) | | | |
| Control Equipment and Materials | Vendor Quote - DSI/ESP/SCR [b] | 4,000,000 | 4,650,000 |
| Aqueous Ammonia System | Vendor Quote | 41,000 | 41,000 |
| Aqueous Ammonia Tank | 10,000 gallon storage tank | 50,000 | 50,000 |
| Piping- NH3 system | Estimate | 5,000 | 5,000 |
| Larger ID Fan | Estimate | 100,000 | 100,000 |
| Transition Ducts to and from SCR | 200 ft @1,800/ft | 360,000 | 360,000 |
| Duct Insulation | Estimate | 60,000 | 60,000 |
| DSI storage silo | | 55,000 | 55,000 |
| Ash hopper/conveyors | | 102,000 | 102,000 |
| Additional NOx Catalyst layer | | 183,000 | 183,000 |
| Additional CO Catalyst layer | | 0 | 200,000 |
| Freight | Vendor estimate | 550,000 | 550,000 |
| Total- Purchased Equipment | | 5,506,000 | 6,356,000 |
| Emission Monitoring | 5% of equipment cost | 275,300 | 317,800 |
| Foundation and Structure Support | 8% of equipment cost | 440,480 | 508,480 |
| Direct Installation Costs (DIC): | | | |
| Erection, Installation | Vendor Quote/Estimate | 600,000 | 650,000 |
| Taxes | Not Required for APC Equipment | 0 | 0 |
| Total DCC (PEC+DIC): | | 6,821,780 | 7,832,280 |
| INDIRECT CAPITAL COSTS (ICC): | | | |
| General Facilities | 5% of DCC | 341,089 | 391,614 |
| Engineering and home office fees | 10% of DCC | 682,178 | 783,228 |
| Process Contingency | 5% of DCC | 341,089 | 391,614 |
| Total ICC: | | 1,364,356 | 1,566,456 |
| PROJECT CONTINGENCY | 15% of DCC+ICC | 1,227,920 | 1,409,810 |
| TOTAL CAPITAL INVESTMENT (TCI): | | 9,414,056 | 10,808,546 |
| DIRECT OPERATING COSTS (DOC): | | | |
| O&M Personnel | Vendor estimate- 1.5% of DCC | 141,211 | 162,128 |
| Trona for DSI [b] | 200 lb/hr; $165/ton | 132,660 | 132,660 |
| ESP Power Cost [b] | 243 kw, respectively; $60/MWh | 117,223 | 117,223 |
| Larger fan power cost | 957,852 Kw-hr/yr | 57,471 | 57,471 |
| Auxiliary Power Cost | 140 kw; $60/MWh | 67,536 | 67,536 |
| Anhydrous Ammonia Cost (19%) [b] | 40 lb/hr NH3; $1/lb NH3 | 321,600 | 321,600 |
| Ash Disposal | 17,000 tons fly ash; $25/ton | 0 | 0 |
| NOx Catalyst replacement | $160,000 every 2 years | 80,000 | 80,000 |
| CO Catalyst Replacement | $400,000 every 2 years | 0 | 200,000 |
| Total DOC: | | 917,701 | 1,138,619 |
| CAPITAL RECOVERY COSTS (CRC): | CRF of 0.0944 times TCI (20 yrs @ 7%) | 888,687 | 1,020,327 |
| ANNUALIZED COSTS (AC): | DOC+ CRC | 1,806,388 | 2,158,945 |

[a] Unless otherwise specified, factors and cost estimates reflect OAQPS Cost Manual, Chapter 4, Section 2, Sixth edition. Operating hours at 8,040 hr/yr.

[b] Based on vendor quote, 2011. Original quote includes CO catalyst at $400,000.

**Table J-4: Cost Effectiveness of Lime Spray Drying FGD with Fabric Filter, HEF Boiler**

| Cost Items | Cost Factors[a] | Cost ($) |
|---|---|---|
| DIRECT CAPITAL COSTS (DCC): | | |
| Purchased Equipment Cost (PEC) | | |
| Absorber + Lime Storage/Delivery | Vendor quote[b] | 5,000,000 |
| Instrumentation | Included | 0 |
| Freight | Included | 0 |
| Taxes | PCE exempt | 0 |
| Total PEC: | | 5,000,000 |
| Direct Installation | | |
| Pebble lime Pneumatic Conveyors | Estimate | 50,000 |
| Foundations | 12% of PEC | 600,000 |
| Piping | Included | 0 |
| Thermal Insulation and Lagging | 1% of PEC | 50,000 |
| Electrical | 1% of PEC | 50,000 |
| Wiring and Lighting | Estimate | 50,000 |
| ID Fan | Estimate | 100,000 |
| Painting | 1% of PEC | 50,000 |
| Emissions Monitoring | 5% of PEC | 250,000 |
| Total Direct Installation: | | 1,200,000 |
| Total DCC (PEC + Direct Installation): | | 6,200,000 |
| INDIRECT CAPITAL COSTS (ICC): | | |
| Engineering | 10% of PEC | 500,000 |
| Construction and field expenses | 10% of PEC | 500,000 |
| Contractor Fees | 10% of PEC | 500,000 |
| Startup | 1% of PEC | 50,000 |
| Performance test | 1% of PEC | 50,000 |
| Contingencies | 3% of PEC | 150,000 |
| Total DCC: | | 1,750,000 |
| TOTAL CAPITAL INVESTMENT (TCI): | DCC + ICC | 7,950,000 |
| DIRECT OPERATING COSTS (DOC): | | |
| (1) Operating Labor | | |
| Operator | 0.5 hr/shift, $16/hr, 8,000 hrs/yr | 8,000 |
| Supervisor | 15% of operator cost | 1,200 |
| (2) Maintenance | | |
| Labor | 0.5 hr/shift, $16/hr, 8,000 hrs/yr | 8,000 |
| Material | 100% of maint. Labor | 8,000 |
| (3) Operating Materials | | |
| Reagent | 1050 lbs/hr, $65/ton | 286,650 |
| (4) Electriciy | 802 KW, $0.04/KW-hr | 281,021 |
| (5) Dry Waste Disposal | 2,290 lbs/hour, $100/ton | 0 |
| Total DOC: | | 592,871 |
| INDIRECT OPERATING COSTS (IOC): | | |
| Overhead | 60% of oper. labor & maintenance material | 15,120 |
| Property Taxes | 1% of TCI | 79,500 |
| Insurance | 1% of TCI | 79,500 |
| Administration | 2% of TCI | 159,000 |
| Total IOC: | | 333,120 |
| CAPITAL RECOVERY COSTS (CRC): | CRF of 0.0944 times TCI (20 yrs @ 7%) | 750,480 |
| ANNUALIZED COSTS (AC): | DOC + IOC + CRC | 1,676,471 |

Footnotes:

[a] Unless otherwise specified, factors and cost estimates reflect OAQPS Cost Manual, Section 5, Chapter 1, Sixth edition.

[b] Based on 2009 Siemens Power cost quote for a 538 MMBtu/hr biomass boiler. Cost of SDA and support equip. only assumed a 40% of total cost of FGD plus baghouse.

## APPENDIX J

## ADDITIONAL EQUIPMENT INFORMATION

**CONFIDENTIAL BUSINESS INFORMATION**
**SUPPLIED UNDER SEPARATE COVER**

# APPENDIX K

## DETAILED SOURCE DATA USED IN THE AAQS AND PSD CLASS II MODELING

**Table K-1: Summary of $SO_2$ Sources Included in the AAQS and PSD Class II Modeling Analyses**

| Facility ID | Facility Name / Emission Unit Description | EU ID | Modeling ID Name | UTM Location X (m) | UTM Location Y (m) | Stack Parameters [a] Height ft | Height m | Diameter ft | Diameter m | Temperature °F | Temperature K | Velocity ft/s | Velocity m/s | $SO_2$ Emission Rate 24-Hour (lb/hr) | 24-Hour (g/sec) | 1-Hour (lb/hr) | 1-Hour (g/sec) | Emissions Data Source | Modeled In AAQS | Modeled In PSD Class II |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0550014 | Lake Placid Asphalt Plant | | | | | | | | | | | | | | | | | | | |
| | Asphalt Plant Barber-Greene Drum Mix | 003 | LPASPH | 465,600 | 3,008,700 | 44.0 | 13.41 | 5.2 | 1.57 | 249.7 | 394.1 | 40.7 | 12.4 | 35.32 | 4.45 | 35.32 | 4.45 | FDEP Data February 2011. | Yes | Yes |
| 0550018 | Tampa Electric Company | | | | | | | | | | | | | | | | | | | |
| | Diesel Generating Unit 1 (19.535 MW) | 001 | TEC1 | 464,300 | 3,035,400 | 150.0 | 45.72 | 5.3 | 1.62 | 334.7 | 441.3 | 101.6 | 31.0 | 459.24 | 57.86 | 459.24 | 57.86 | Permit No. 0550018-004-AV, 172 MMBtu/hr and 2.67 lb/MMBtu $SO_2$ limit. | Yes | Yes |
| | Diesel Generating Unit 2 (19.535 MW) | 002 | TEC2 | 464,300 | 3,035,400 | 150.0 | 45.72 | 5.3 | 1.62 | 349.7 | 449.7 | 102.4 | 31.2 | 459.24 | 57.86 | 459.24 | 57.86 | Permit No. 0550018-004-AV, 172 MMBtu/hr and 2.67 lb/MMBtu $SO_2$ limit. | Yes | Yes |
| | Auxiliary Steam Boiler | 004 | TEC4 | 464,300 | 3,035,400 | 62.0 | 18.90 | 2.2 | 0.67 | 399.7 | 477.4 | 12.6 | 3.8 | 5.38 | 0.68 | 5.38 | 0.68 | Permit No. 0550018-004-AV, 10.46 MMBtu/hr 138,000 btu/gal for 0.5% Sulfur No. 2 Fuel Oil, and AP-42 Table 1.3-1 emission factor for $SO_2$ of 142S lb/$10^3$gal. | Yes | Yes |
| 0550003 | Progress Energy - Avon Park | | | | | | | | | | | | | | | | | | | |
| | Gas Turbine Peaking Unit No. 1 | 003 | APTURB1 | 451,400 | 3,050,500 | 55.0 | 16.76 | 10.0 | 3.05 | 849.7 | 727.4 | 424.0 | 129.2 | 577.0 | 72.70 | 577.0 | 72.70 | Based on Permit No. 0550003-005-AV, 526.6 MMBtu/hr, firing No. 2 fuel oil. | Yes | Yes |
| | Gas Turbine Peaking Unit No. 2 | 004 | APTURB2 | 451,400 | 3,050,500 | 55.0 | 16.76 | 10.0 | 3.05 | 849.7 | 727.4 | 424.4 | 129.4 | 577.0 | 72.70 | 577.0 | 72.70 | Based on Permit No. 0550003-005-AV, 526.6 MMBtu/hr, firing No. 2 fuel oil. | Yes | Yes |
| 0270016 | Desoto County Energy Park | | | | | | | | | | | | | | | | | | | |
| | 170MW Simple Cycle Comb Turbine | 001 | DESOU1 | 419,840 | 3,011,840 | 75.0 | 22.86 | 23.0 | 7.01 | 1112.7 | 873.6 | 106.1 | 32.3 | 98.70 | 12.44 | NA | NA | Based on Permit No. 0270016-007-AV. | Yes | Yes |
| | 170MW Simple Cycle Comb Turbine | 002 | DESOU2 | 419,840 | 3,011,840 | 75.0 | 22.86 | 23.0 | 7.01 | 1112.7 | 873.6 | 106.1 | 32.3 | 98.70 | 12.44 | NA | NA | Based on Permit No. 0270016-007-AV. | Yes | Yes |

[a] Stack parameter source: FDEP Data February 2011.

**Table K-2: Summary of $PM_{10}/PM_{2.5}$ Sources Included in the AAQS and PSD Class II Modeling Analyses**

| Facility ID | Facility Name / Emission Unit Description | EU ID | Modeling ID Name | UTM Location X (m) | UTM Location Y (m) | Stack Parameters[a] Height ft | Height m | Diameter ft | Diameter m | Temperature °F | Temperature K | Velocity ft/s | Velocity m/s | $PM_{10}$ Emission Rate 24-Hour (lb/hr) | 24-Hour (g/sec) | Emissions Data Source | Modeled In AAQS | PSD Class II |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0550014 | Lake Placid Asphalt Plant | | | | | | | | | | | | | | | | | |
| | Asphalt Plant Barber-Greene Drum Mix | 003 | LPASPH | 465,600 | 3,008,700 | 44.0 | 13.41 | 5.2 | 1.57 | 249.7 | 394.1 | 40.7 | 12.4 | 10.44 | 1.32 | 0550014-006-AO - 0.04 gr/dscf 3-hr average limit, and 30,448.6 dscfm. | Yes | Yes |

[a] Stack parameter source: FDEP Data February 2011.

Table K-3: Summary of 1-Hour $NO_x$ Sources Included in the AAQS Modeling Analysis

| Facility ID | Facility Name / Emission Unit Description | EU ID | Modeling ID Name | UTM Location X (m) | UTM Location Y (m) | Stack Parameters [a] Height ft | Height m | Diameter ft | Diameter m | Temperature °F | Temperature K | Velocity ft/s | Velocity m/s | $NO_x$ Emission Rate 1-Hour (lb/hr) | 1-Hour (g/sec) | $NO_2/NO_x$ Ratio | Emissions Data Source | Modeled In AAQS |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0550014 | Lake Placid Asphalt Plant | | | | | | | | | | | | | | | | | |
| | Asphalt Plant Barber-Greene Drum Mix | 003 | LPASPH | 465,600 | 3,008,700 | 44.0 | 13.41 | 5.2 | 1.57 | 249.7 | 394.1 | 40.7 | 12.4 | 15.0 | 1.89 | 1.0 | FDEP Data February 2011 . | Yes |
| 0550018 | Tampa Electric Company | | | | | | | | | | | | | | | | | |
| | Diesel Generating Unit 1 (19.535 MW) | 001 | TEC1 | 464,300 | 3,035,400 | 150.0 | 45.72 | 5.3 | 1.62 | 334.7 | 441.3 | 101.6 | 31.0 | 572 | 72.07 | 1.0 | Permit No. 0550018-004-AV. | Yes |
| | Diesel Generating Unit 2 (19.535 MW) | 002 | TEC2 | 464,300 | 3,035,400 | 150.0 | 45.72 | 5.3 | 1.62 | 349.7 | 449.7 | 102.4 | 31.2 | 572 | 72.07 | 1.0 | Permit No. 0550018-004-AV. | Yes |
| | Auxiliary Steam Boiler | 004 | TEC4 | 464,300 | 3,035,400 | 62.0 | 18.90 | 2.2 | 0.67 | 399.7 | 477.4 | 12.6 | 3.8 | 1.52 | 0.19 | 1.0 | Permit No. 0550018-004-AV, 10.46 MMBtu/hr 138,000 btu/gal for No. 2 Fuel Oil, and AP-42 Table 1.3-1 emission factor for $NO_x$ of 20 lb/$10^3$gal. | Yes |
| 0550003 | Progress Energy - Avon Park | | | | | | | | | | | | | | | | | |
| | Gas Turbine Peaking Unit No. 1 | 003 | APTURB1 | 451,400 | 3,050,500 | 55.0 | 16.76 | 10.0 | 3.05 | 849.7 | 727.4 | 424.0 | 129.2 | 495.1 | 62.38 | 1.0 | Based on Permit No. 0550003-005-AV, 526.6 MMBtu/hr, firing No. 2 fuel oil, and AP-42 Table 3.1-1 emission factor of 0.88 lb/MMBtu for No. 2 fuel oil, uncontrolled. | Yes |
| | Gas Turbine Peaking Unit No. 2 | 004 | APTURB2 | 451,400 | 3,050,500 | 55.0 | 16.76 | 10.0 | 3.05 | 849.7 | 727.4 | 424.4 | 129.4 | 495.1 | 62.38 | 1.0 | Based on Permit No. 0550003-005-AV, 526.6 MMBtu/hr, firing No. 2 fuel oil, and AP-42 Table 3.1-1 emission factor of 0.88 lb/MMBtu for No. 2 fuel oil, uncontrolled. | Yes |

[a] Stack parameter source: FDEP Data February 2011.

## APPENDIX L

## APPLICATION FOR AIR PERMIT – LONG FORM

# Department of Environmental Protection

## Division of Air Resource Management

## APPLICATION FOR AIR PERMIT - LONG FORM

### I. APPLICATION INFORMATION

**Air Construction Permit** – Use this form to apply for an air construction permit:

- For any required purpose at a facility operating under a federally enforceable state air operation permit (FESOP) or Title V air operation permit;
- For a proposed project subject to prevention of significant deterioration (PSD) review, nonattainment new source review, or maximum achievable control technology (MACT);
- To assume a restriction on the potential emissions of one or more pollutants to escape a requirement such as PSD review, nonattainment new source review, MACT, or Title V; or
- To establish, revise, or renew a plantwide applicability limit (PAL).

**Air Operation Permit** – Use this form to apply for:

- An initial federally enforceable state air operation permit (FESOP); or
- An initial, revised, or renewal Title V air operation permit.

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BUREAU OF AIR REGULATION

**To ensure accuracy, please see form instructions.**

**Identification of Facility**

| | |
|---|---|
| 1. Facility Owner/Company Name: **Highlands EnviroFuels, LLC** | |
| 2. Site Name: **Highlands Ethanol and Cogeneration Plant** | |
| 3. Facility Identification Number: 0550063 | |
| 4. Facility Location...<br>Street Address or Other Locator: **One mile west of Hwy 27 and south of SR 70**<br>City: **Lake Placid** County: **Highlands** Zip Code: **33852** | |
| 5. Relocatable Facility?<br>☐ Yes ☒ No | 6. Existing Title V Permitted Facility?<br>☐ Yes ☒ No |

**Application Contact**

| |
|---|
| 1. Application Contact Name: **Bradley Krohn, President & Managing Member** |
| 2. Application Contact Mailing Address...<br>Organization/Firm: **Highlands EnviroFuels, LLC**<br>Street Address: **10027 Water Works Lane**<br>City: **Riverview** State: **FL** Zip Code: **33578** |
| 3. Application Contact Telephone Numbers...<br>Telephone: **(813) 425-5478** ext. Fax: **(813) 672-3877** |
| 4. Application Contact E-mail Address: **Bkrohn@usenvirofuels.com** |

**Application Processing Information (DEP Use)**

| | |
|---|---|
| 1. Date of Receipt of Application: | 3. PSD Number (if applicable): |
| 2. Project Number(s): | 4. Siting Number (if applicable): |

## APPLICATION INFORMATION

### Purpose of Application

**This application for air permit is being submitted to obtain: (Check one)**

**Air Construction Permit**

- ☒ Air construction permit.
- ☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL).
- ☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL), and separate air construction permit to authorize construction or modification of one or more emissions units covered by the PAL.

**Air Operation Permit**

- ☐ Initial Title V air operation permit.
- ☐ Title V air operation permit revision.
- ☐ Title V air operation permit renewal.
- ☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.
- ☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

**Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)**

- ☐ Air construction permit and Title V permit revision, incorporating the proposed project.
- ☐ Air construction permit and Title V permit renewal, incorporating the proposed project.

**Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:**

- ☐ I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

### Application Comment

**PSD air construction permit application for a sugarcane/sweet sorghum-to-ethanol plant and cogeneration facility located in Highlands County, Florida. The facility will consist of an ethanol production plant, a biomass boiler, a 30 MW turbine generator, a biomass handling system, and various storage tanks and product loadout system.**

## APPLICATION INFORMATION

### Scope of Application

| Emissions Unit ID Number | Description of Emissions Unit | Air Permit Type | Air Permit Processing Fee |
|---|---|---|---|
| | Biomass Boiler | AC1A | |
| | Ethanol Production Process | AC1A | |
| | Biomass Handling System | AC1A | |
| | Product Load Out | AC1A | |
| | NSPS Storage Tanks | AC1A | |
| | Emergency Electrical Generator | AC1A | |
| | Emergency Fire Pump | AC1A | |
| | Miscellaneous Unregulated Emission Units | AC1A | |
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| | | | |

### Application Processing Fee

**Check one:** ☒ Attached - Amount: $ 7,500 ☐ Not Applicable

## APPLICATION INFORMATION

**Owner/Authorized Representative Statement**

**Complete if applying for an air construction permit or an initial FESOP.**

1. Owner/Authorized Representative Name :
   **Bradley Krohn, President & Managing Member**
2. Owner/Authorized Representative Mailing Address...
   Organization/Firm: **Highlands EnviroFuels, LLC**
   Street Address: **10027 Water Works Lane**
   City: **Riverview** State: **FL** Zip Code: **33578**
3. Owner/Authorized Representative Telephone Numbers...
   Telephone: **(813) 425-5478** ext. Fax: **(813) 672-3877**
4. Owner/Authorized Representative E-mail Address: **BKrohn@usenvirofuels.com**
5. Owner/Authorized Representative Statement:

   *I, the undersigned, am the owner or authorized representative of the corporation, partnership, or other legal entity submitting this air permit application. To the best of my knowledge, the statements made in this application are true, accurate and complete, and any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department.*

   [signature]
   Signature

   May 25, 2011
   Date

## APPLICATION INFORMATION

### Application Responsible Official Certification

**Complete if applying for an initial, revised, or renewal Title V air operation permit or concurrent processing of an air construction permit and revised or renewal Title V air operation permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."**

| |
|---|
| 1. Application Responsible Official Name: |
| 2. Application Responsible Official Qualification (Check one or more of the following options, as applicable):<br>☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C.<br>☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively.<br>☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official.<br>☐ The designated representative at an Acid Rain source or CAIR source. |
| 3. Application Responsible Official Mailing Address...<br>Organization/Firm:<br>Street Address:<br>City: State: Zip Code: |
| 4. Application Responsible Official Telephone Numbers...<br>Telephone: ( ) ext. Fax: ( ) |
| 5. Application Responsible Official E-mail Address: |
| 6. Application Responsible Official Certification:<br>I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.<br><br>Signature Date |

## APPLICATION INFORMATION

**Professional Engineer Certification**

1. Professional Engineer Name: **David A. Buff**
   Registration Number: **19011**
2. Professional Engineer Mailing Address...
   Organization/Firm: **Golder Associates Inc.****
   Street Address: **6026 NW 1st Place**
   City: **Gainesville** State: **FL** Zip Code: **32607**
3. Professional Engineer Telephone Numbers...
   Telephone: **(352) 336-5600** ext. Fax: **(352) 336-6603**
4. Professional Engineer E-mail Address: **dbuff@golder.com**
5. Professional Engineer Statement:

*I, the undersigned, hereby certify, except as particularly noted herein*, that:*

*(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and*

*(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.*

*(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.*

*(4) If the purpose of this application is to obtain an air construction permit (check here ☒, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.*

*(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☐, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.*

David A. Buff — 5/31/11

Signature — Date

(seal)

* Attach any exception to certification statement.

**Board of Professional Engineers Certificate of Authorization #00001670.

# II. FACILITY INFORMATION

## A. GENERAL FACILITY INFORMATION

**Facility Location and Type**

| | | | |
|---|---|---|---|
| 1. Facility UTM Coordinates... Zone **17** East (km) **466.407** North (km) **3,009.015** | | 2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **27°12'12.42"** Longitude (DD/MM/SS) **81°20'21.115"** | |
| 3. Governmental Facility Code: **0** | 4. Facility Status Code: **C** | 5. Facility Major Group SIC Code: **28, 49** | 6. Facility SIC(s): **2869** **4911** |
| 7. Facility Comment : | | | |

**Facility Contact**

| |
|---|
| 1. Facility Contact Name: **Bradley Krohn, President & Managing Member** |
| 2. Facility Contact Mailing Address... Organization/Firm: **Highlands EnviroFuels, LLC** Street Address: **10027 Water Works Lane** City: **Riverview** State: **FL** Zip Code: **33578** |
| 3. Facility Contact Telephone Numbers: Telephone: **(954) 492-1588** ext. Fax: **(954) 492-0331** |
| 4. Facility Contact E-mail Address: **BKrohn@usenvirofuels.com** |

**Facility Primary Responsible Official**

**Complete if an "application responsible official" is identified in Section I that is not the facility "primary responsible official."**

| |
|---|
| 1. Facility Primary Responsible Official Name: |
| 2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code: |
| 3. Facility Primary Responsible Official Telephone Numbers... Telephone: ( ) ext. Fax: ( ) |
| 4. Facility Primary Responsible Official E-mail Address: |

## Facility Regulatory Classifications

**Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a "major source" and a "synthetic minor source."**

| | |
|---|---|
| 1. ☐ Small Business Stationary Source | ☐ Unknown |
| 2. ☐ Synthetic Non-Title V Source | |
| 3. ☒ Title V Source | |
| 4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs) | |
| 5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs | |
| 6. ☐ Major Source of Hazardous Air Pollutants (HAPs) | |
| 7. ☐ Synthetic Minor Source of HAPs | |
| 8. ☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60) | |
| 9. ☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60) | |
| 10. ☒ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63) | |
| 11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5)) | |
| 12. Facility Regulatory Classifications Comment: | |

## List of Pollutants Emitted by Facility

| 1. Pollutant Emitted | 2. Pollutant Classification | 3. Emissions Cap [Y or N]? |
|---|---|---|
| **Particulate Matter Total - PM** | **B** | **N** |
| **Particulate Matter - PM10** | **B** | **N** |
| **Particulate Matter - PM2.5** | **B** | **N** |
| **Sulfur Dioxide - SO2** | **A** | **N** |
| **Nitrogen Oxides - NOX** | **A** | **N** |
| **Carbon Monoxide - CO** | **A** | **N** |
| **Volatile Organic Compounds - VOC** | **A** | **N** |
| **Lead - Pb** | **B** | **N** |
| **Ammonia - NH3** | **B** | **N** |
| | | |
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| | | |

## B. EMISSIONS CAPS

**Facility-Wide or Multi-Unit Emissions Caps**

| 1. Pollutant Subject to Emissions Cap | 2. Facility-Wide Cap [Y or N]? (all units) | 3. Emissions Unit ID's Under Cap (if not all units) | 4. Hourly Cap (lb/hr) | 5. Annual Cap (ton/yr) | 6. Basis for Emissions Cap |
|---|---|---|---|---|---|
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7. Facility-Wide or Multi-Unit Emissions Cap Comment:

## C. FACILITY ADDITIONAL INFORMATION

**Additional Requirements for All Applications, Except as Otherwise Stated**

| | |
|---|---|
| 1. | Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)<br>☒ Attached, Document ID: **PSD Report** ☐ Previously Submitted, Date:__________ |
| 2. | Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)<br>☒ Attached, Document ID: **PSD Report** ☐ Previously Submitted, Date:__________ |
| 3. | Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)<br>☒ Attached, Document ID: **HEF-FI-C3** ☐ Previously Submitted, Date:__________ |

**Additional Requirements for Air Construction Permit Applications**

| | |
|---|---|
| 1. | Area Map Showing Facility Location:<br>☒ Attached, Document ID: **PSD Report** ☐ Not Applicable (existing permitted facility) |
| 2. | Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL):<br>☒ Attached, Document ID: **PSD Report** |
| 3. | Rule Applicability Analysis:<br>☒ Attached, Document ID: **PSD Report** |
| 4. | List of Exempt Emissions Units:<br>☐ Attached, Document ID:__________ ☒ Not Applicable (no exempt units at facility) |
| 5. | Fugitive Emissions Identification:<br>☒ Attached, Document ID: **PSD Report** ☐ Not Applicable |
| 6. | Air Quality Analysis (Rule 62-212.400(7), F.A.C.):<br>☒ Attached, Document ID: **PSD Report** ☐ Not Applicable |
| 7. | Source Impact Analysis (Rule 62-212.400(5), F.A.C.):<br>☒ Attached, Document ID: **PSD Report** ☐ Not Applicable |
| 8. | Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.):<br>☒ Attached, Document ID: **PSD Report** ☐ Not Applicable |
| 9. | Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.):<br>☒ Attached, Document ID: **PSD Report** ☐ Not Applicable |
| 10. | Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.):<br>☐ Attached, Document ID:__________ ☒ Not Applicable |

## C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

**Additional Requirements for FESOP Applications**

| |
|---|
| 1. List of Exempt Emissions Units:<br>☐ Attached, Document ID:__________ ☐ Not Applicable (no exempt units at facility) |

**Additional Requirements for Title V Air Operation Permit Applications**

| |
|---|
| 1. List of Insignificant Activities: (Required for initial/renewal applications only)<br>☐ Attached, Document ID:__________ ☐ Not Applicable (revision application) |
| 2. Identification of Applicable Requirements: (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought)<br>☐ Attached, Document ID:__________<br>☐ Not Applicable (revision application with no change in applicable requirements) |
| 3. Compliance Report and Plan: (Required for all initial/revision/renewal applications)<br>☐ Attached, Document ID:__________<br>Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing. |
| 4. List of Equipment/Activities Regulated under Title VI: (If applicable, required for initial/renewal applications only)<br>☐ Attached, Document ID:__________<br>☐ Equipment/Activities Onsite but Not Required to be Individually Listed<br>☐ Not Applicable |
| 5. Verification of Risk Management Plan Submission to EPA: (If applicable, required for initial/renewal applications only)<br>☐ Attached, Document ID:__________ ☐ Not Applicable |
| 6. Requested Changes to Current Title V Air Operation Permit:<br>☐ Attached, Document ID:__________ ☐ Not Applicable |

## C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

**Additional Requirements for Facilities Subject to Acid Rain, CAIR, or Hg Budget Program**

| | |
|---|---|
| 1. | Acid Rain Program Forms:<br>Acid Rain Part Application (DEP Form No. 62-210.900(1)(a)):<br>☐ Attached, Document ID:________ ☐ Previously Submitted, Date:________<br>☒ Not Applicable (not an Acid Rain source)<br>Phase II $NO_X$ Averaging Plan (DEP Form No. 62-210.900(1)(a)1.):<br>☐ Attached, Document ID:________ ☐ Previously Submitted, Date:________<br>☒ Not Applicable<br>New Unit Exemption (DEP Form No. 62-210.900(1)(a)2.):<br>☐ Attached, Document ID:________ ☐ Previously Submitted, Date:________<br>☒ Not Applicable |
| 2. | CAIR Part (DEP Form No. 62-210.900(1)(b)):<br>☐ Attached, Document ID:________ ☐ Previously Submitted, Date:________<br>☒ Not Applicable (not a CAIR source) |

**Additional Requirements Comment**

| |
|---|
| |

## ATTACHMENT HEF-FI-C3

## PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

# ATTACHMENT HEF-FI-C3

## PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

Highlands EnviroFuels (HEF) takes reasonable precautions to prevent emissions of unconfined particulate matter at the biomass ethanol facility. These consist of the following:

- Conveyor systems and associated drop points shall be enclosed or partially enclosed.
- Drop points to supplemental biomass storage areas shall be designed to minimize the overall exposed (or exposed to atmosphere) drop height.
- Periodic equipment maintenance shall be performed to maintain conveyor systems and associated drop point integrity. Appropriate plant records shall be maintained on equipment maintenance performed.
- Daily observations of the conveyor systems and associated drop point integrity to identify any equipment abnormalities.
- Plant personnel shall be trained on identification of warning signs for potential equipment malfunction.
- Procedures shall be established for defining excessive fugitive dust from woody biomass truck unloading operations. Plant personnel shall visually observe truck unloading operations and if excessive fugitive dust is detected appropriate fugitive dust minimization techniques shall be implemented. Plant personnel shall be trained on procedures for defining and minimizing excessive dust from the truck unloading operations.
- All main roadways at the plant shall be paved.
- Plant gravel areas shall be wetted during dry conditions, as required, to minimize fugitive dust emissions.
- Mud, dirt or similar debris shall be removed promptly from the paved roads by vacuum sweeping or watering.
- Plant personnel shall be trained on what constitutes excessive dust on paved roads.

# III. EMISSIONS UNIT INFORMATION

**Title V Air Operation Permit Application** - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for an initial, revised or renewal Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

**Air Construction Permit or FESOP Application** - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for an air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

**Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application** – Where this application is used to apply for both an air construction permit and a revised or renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes, and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this application that is subject to air construction permitting and for each such emissions unit that is a regulated or unregulated unit for purposes of Title V permitting. (An emissions unit may be exempt from air construction permitting but still be classified as an unregulated unit for Title V purposes.) Emissions units classified as insignificant for Title V purposes are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

EMISSIONS UNIT INFORMATION
Section [1]
**Biomass Boiler**

## A. GENERAL EMISSIONS UNIT INFORMATION

**Title V Air Operation Permit Emissions Unit Classification**

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

**Emissions Unit Description and Status**

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
**Biomass Boiler**

3. Emissions Unit Identification Number:

| 4. Emissions Unit Status Code: | 5. Commence Construction Date: | 6. Initial Startup Date: | 7. Emissions Unit Major Group SIC Code: |
|---|---|---|---|
| **C** | | | **49, 28** |

8. Federal Program Applicability: (Check all that apply)

   ☐ Acid Rain Unit

   ☐ CAIR Unit

9. Package Unit:
Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:
**The Boiler can be fired by biomass (Sugar Cane Bagasse, Sweet Sorghum Bagasse, or Wood) and Natural Gas can be used as backup/supplemental fuel.**

**Emissions Unit Control Equipment/Method:** Control 1 of 4

| | |
|---|---|
| 1. Control Equipment/Method Description: **Dry Sorbent Injection - Acid Gas Removal** | |
| 2. Control Device or Method Code: **206** | |

**Emissions Unit Control Equipment/Method:** Control 2 of 4

| | |
|---|---|
| 1. Control Equipment/Method Description: **Single Cyclone** | |
| 2. Control Device or Method Code: **075** | |

**Emissions Unit Control Equipment/Method:** Control 3 of 4

| | |
|---|---|
| 1. Control Equipment/Method Description: **ESP - Electrostatic Precipitator - High Efficiency** | |
| 2. Control Device or Method Code: **010** | |

**Emissions Unit Control Equipment/Method:** Control 4 of 4

| | |
|---|---|
| 1. Control Equipment/Method Description: **Selective Non-Catalytic Reduction for NOx** | |
| 2. Control Device or Method Code: **107** | |

## B. EMISSIONS UNIT CAPACITY INFORMATION
### (Optional for unregulated emissions units.)

**Emissions Unit Operating Capacity and Schedule**

| | |
|---|---|
| 1. Maximum Process or Throughput Rate: | |
| 2. Maximum Production Rate: | |
| 3. Maximum Heat Input Rate: **504** million Btu/hr | |
| 4. Maximum Incineration Rate: pounds/hr<br>tons/day | |
| 5. Requested Maximum Operating Schedule:<br>**24** hours/day<br>**49** weeks/year | <br>**7** days/week<br>**8,760** hours/year |
| 6. Operating Capacity/Schedule Comment:<br>**Maximum heat input rate based on a maximum 275,000 lb/hr of steam production. Maximum 24-hour rates are 250,000 lb/hr steam and 458.5 MMBtu/hr on biomass. Maximum heat input for natural gas is 249 MMBtu/hr.** | |

## C. EMISSION POINT (STACK/VENT) INFORMATION
### (Optional for unregulated emissions units.)

**Emission Point Description and Type**

| | |
|---|---|
| 1. Identification of Point on Plot Plan or Flow Diagram: **BLR** | 2. Emission Point Type Code: **1** |
| 3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: | |
| 4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: | |

| | | |
|---|---|---|
| 5. Discharge Type Code: **V** | 6. Stack Height: **150** feet | 7. Exit Diameter: **14.0** feet |
| 8. Exit Temperature: **340°F** | 9. Actual Volumetric Flow Rate: **204,080** acfm | 10. Water Vapor: **25** % |

| | |
|---|---|
| 11. Maximum Dry Standard Flow Rate: **101,300** dscfm | 12. Nonstack Emission Point Height: **8** feet |
| 13. Emission Point UTM Coordinates... Zone: East (km): North (km): | 14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS) |
| 15. Emission Point Comment: **Flow rates based on 458.5 MMBtu/hr (24-hr average). Maximum dry standard flow rate is at 4.1% $O_2$.** | |

## D. SEGMENT (PROCESS/FUEL) INFORMATION

**Segment Description and Rate:** Segment **1** of **4**

| | | |
|---|---|---|
| 1. Segment Description (Process/Fuel Type): **Electric Utility Boiler - Bagasse (Sugarcane)** | | |
| 2. Source Classification Code (SCC): **1-01-011-01** | 3. SCC Units: **Tons Burned** | |
| 4. Maximum Hourly Rate: **64.66** | 5. Maximum Annual Rate: **236,300** | 6. Estimated Annual Activity Factor: |
| 7. Maximum % Sulfur: **0.06** | 8. Maximum % Ash: **1.5** | 9. Million Btu per SCC Unit: **7.8** |
| 10. Segment Comment: **Maximum annual rate based on 750,000 tons of sugar cane harvested per year. Maximum hourly rate based on 504 MMBtu/hr and 7.8 MMBtu/ton (wet). See Table 2-3 in PSD Report.** | | |

**Segment Description and Rate:** Segment **2** of **4**

| | | |
|---|---|---|
| 1. Segment Description (Process/Fuel Type): **Electric Utility Boiler - Bagasse (Sweet Sorghum)** | | |
| 2. Source Classification Code (SCC): **1-01-011-01** | 3. SCC Units: **Tons Burned** | |
| 4. Maximum Hourly Rate: **64.66** | 5. Maximum Annual Rate: **236,300** | 6. Estimated Annual Activity Factor: |
| 7. Maximum % Sulfur: **0.11** | 8. Maximum % Ash: **2.7** | 9. Million Btu per SCC Unit: **7.8** |
| 10. Segment Comment: **Maximum annual rate based on 750,000 tons of sweet sorghum harvested per year. Maximum hourly rate based on 504 MMBtu/hr and 7.8 MMBtu/ton (wet) sweet sorghum bagasse. See Table 2-3 in PSD Report.** | | |

## D. SEGMENT (PROCESS/FUEL) INFORMATION (CONTINUED)

**Segment Description and Rate:** Segment 3 of 4

| | | |
|---|---|---|
| 1. Segment Description (Process/Fuel Type): **Electric Utility Boiler - Wood-fired** | | |
| 2. Source Classification Code (SCC): **1-01-009-03** | 3. SCC Units: **Tons Burned** | |
| 4. Maximum Hourly Rate: **59.33** | 5. Maximum Annual Rate: **43,368** | 6. Estimated Annual Activity Factor: |
| 7. Maximum % Sulfur: **0.07** | 8. Maximum % Ash: **9.0** | 9. Million Btu per SCC Unit: **8.5** |
| 10. Segment Comment: **Maximum hourly rate based on 504 MMBtu/hr. See Table 2-3 in PSD Report for annual rate calculation.** | | |

**Segment Description and Rate:** Segment 4 of 4

| | | |
|---|---|---|
| 1. Segment Description (Process/Fuel Type): **Electric Utility Boiler - Natural Gas** | | |
| 2. Source Classification Code (SCC): **1-01-006-01** | 3. SCC Units: **Million cubic feet burned** | |
| 4. Maximum Hourly Rate: **0.244** | 5. Maximum Annual Rate: **1,021** | 6. Estimated Annual Activity Factor: |
| 7. Maximum % Sulfur: | 8. Maximum % Ash: | 9. Million Btu per SCC Unit: **1,020** |
| 10. Segment Comment: **Maximum hourly rate based on 249 MMBtu/hr. See PSD Table 2-3.** | | |

## E. EMISSIONS UNIT POLLUTANTS

**List of Pollutants Emitted by Emissions Unit**

| 1. Pollutant Emitted | 2. Primary Control Device Code | 3. Secondary Control Device Code | 4. Pollutant Regulatory Code |
|---|---|---|---|
| PM | 075 | 010 | EL |
| PM10 | 075 | 010 | EL |
| PM2.5 | 075 | 010 | NS |
| SO2 | 206 | | EL |
| NOx | 107 | | EL |
| CO | | | EL |
| VOC | | | EL |
| Mercury Compounds (H114) | | | NS |
| Lead (Pb) | 075 | 010 | NS |
| Sulfuric Acid Mist (SAM) | 206 | | NS |
| Fluorides - Total (FL) | | | NS |
| Total HAPs (HAPs) | | | EL |
| Ammonia - NH3 | | | EL |
| | | | |
| | | | |
| | | | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>**

| | |
|---|---|
| 1. Pollutant Emitted: **PM** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **7.6** lb/hour **27.6** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **0.015 lb/MMBtu**<br>Reference: **Proposed BACT Limit** | 7. Emissions Method Code: **0** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |

10. Calculation of Emissions:
**0.015 lb/MMBtu x 504 MMBtu/hr = 7.6 lb/hr**

**See PSD Tables 2-12 for short-term averaging time calculations and 2-13 for annual averaging time calculations.**

11. Potential, Fugitive, and Actual Emissions Comment:
**Based on biomass firing.**

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions 1 of 2

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: **OTHER** | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: **0.015 lb/MMBtu** | 4. Equivalent Allowable Emissions: **7.6** lb/hour **27.6** tons/year |
| 5. Method of Compliance: **Annual stack testing using EPA Method 5.** | |
| 6. Allowable Emissions Comment (Description of Operating Method): **Proposed BACT. Based on biomass firing.** | |

**Allowable Emissions** Allowable Emissions 2 of 2

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: **OTHER** | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: **0.0075 lb/MMBtu** | 4. Equivalent Allowable Emissions: **1.9** lb/hour **3.9** tons/year |
| 5. Method of Compliance: **Good combustion practices.** | |
| 6. Allowable Emissions Comment (Description of Operating Method): **Proposed BACT. Hourly based on 100% natural gas firing.**<br>**Hourly: 0.0075 lb/MMBtu x 249 MMBtu/hr = 1.9 lb/hr**<br>**Annual: 0.0075 lb/MMBtu/hr x 1,041,553 MMBtu/yr x 1 ton/2,000 lb = 3.9 TPY** | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

# F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **PM10** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **7.6** lb/hour **27.6** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **0.015 lb/MMBtu**<br>Reference: **Proposed BACT Limit** | 7. Emissions Method Code: **0** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |

10. Calculation of Emissions:

**0.015 lb/MMBtu x 504 MMBtu/hr = 7.6 lb/hr**

**See PSD Tables 2-12 for short-term averaging time calculations and 2-13 for annual averaging time calculations.**

11. Potential, Fugitive, and Actual Emissions Comment:

**Based on biomass firing.**

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions 1 of 2

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: **OTHER** | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: **0.015 lb/MMBtu** | 4. Equivalent Allowable Emissions: **7.6** lb/hour **27.6** tons/year |
| 5. Method of Compliance: **Annual stack testing using EPA Method 5.** | |
| 6. Allowable Emissions Comment (Description of Operating Method): **Proposed BACT. Based on biomass firing.** | |

**Allowable Emissions** Allowable Emissions 2 of 2

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: **OTHER** | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: **0.0075 lb/MMBtu** | 4. Equivalent Allowable Emissions: **1.9** lb/hour **3.9** tons/year |
| 5. Method of Compliance: **Good combustion practices.** | |
| 6. Allowable Emissions Comment (Description of Operating Method): **Proposed BACT. Hourly based on 100% natural gas firing.**<br>**Hourly: 0.0075 lb/MMBtu x 249 MMBtu/hr = 1.9 lb/hr**<br>**Annual: 0.0075 lb/MMBtu/hr x 1,041,553 MMBtu/yr x 1 ton/2,000 lb = 3.9 TPY** | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **PM2.5** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **4.9** lb/hour **18.0** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **0.010 lb/MMBtu**<br>Reference: **Proposed BACT Limit** | 7. Emissions Method Code: **0** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |

10. Calculation of Emissions:
**0.0098 lb/MMBtu x 504 MMBtu/hr = 4.9 lb/hr**

**See PSD Tables 2-12 for short-term averaging time calculations and 2-13 for annual averaging time calculations.**

11. Potential, Fugitive, and Actual Emissions Comment:
**Based on biomass firing.**

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions 1 of 2

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: **OTHER** | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: **0.0098 lb/MMBtu** | 4. Equivalent Allowable Emissions: **4.9** lb/hour **18.0** tons/year |
| 5. Method of Compliance: **Annual stack testing using EPA Method 5.** | |
| 6. Allowable Emissions Comment (Description of Operating Method): **Proposed BACT. Based on biomass firing.** | |

**Allowable Emissions** Allowable Emissions 2 of 2

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: **OTHER** | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: **0.0075 lb/MMBtu** | 4. Equivalent Allowable Emissions: **1.9** lb/hour **3.9** tons/year |
| 5. Method of Compliance: **Good combustion practices.** | |
| 6. Allowable Emissions Comment (Description of Operating Method): **Proposed BACT. Hourly based on 100% natural gas firing.**<br>**Hourly: 0.0075 lb/MMBtu x 249 MMBtu/hr = 1.9 lb/hr**<br>**Annual: 0.0075 lb/MMBtu/hr x 1,041,553 MMBtu/yr x 1 ton/2,000 lb = 3.9 TPY** | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **SO2** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **70.6** lb/hour **200.4** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **0.078 lb/MMBtu, 12-month rolling average.**<br>Reference: **Proposed BACT Limit.** | 7. Emissions Method Code: **0** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |

10. Calculation of Emissions:
**Short-term emissions based on uncontrolled emissions of 0.56 lb/MMBtu and 75% control.**

**504 MMBtu/hr x 0.14 lb/MMBtu = 70.6 lb/hr**

**See PSD Tables 2-12 and 2-13 for calculations.**

11. Potential, Fugitive, and Actual Emissions Comment:
**Based on biomass firing.**

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions 1 of 2

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: **OTHER** | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: **0.14 lb/MMBtu** | 4. Equivalent Allowable Emissions: **70.6** lb/hour **200.4** tons/year |
| 5. Method of Compliance: **Continuous $SO_2$ monitor.** | |
| 6. Allowable Emissions Comment (Description of Operating Method): **Based on worst-case biomass and short term averaging time. See PSD Tables 2-12 and 2-13.** | |

**Allowable Emissions** Allowable Emissions 2 of 2

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: **OTHER** | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: **0.00059 lb/MMBtu** | 4. Equivalent Allowable Emissions: **0.15** lb/hour **2** tons/year |
| 5. Method of Compliance: **Good combustion practices.** | |
| 6. Allowable Emissions Comment (Description of Operating Method): **Proposed BACT. Hourly based on 100% natural gas firing.**<br>**Hourly: 0.00059 lb/MMBtu x 249 MMBtu/hr = 0.15 lb/hr**<br>**Annual: 0.00059 lb/MMBtu x 1,041,553 MMBtu/yr x 1 ton/2,000 lb = 0.31 TPY** | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **NOx** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **126.1** lb/hour **184.3** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **0.10 lb/MMBtu, 30-day rolling average.**<br>Reference: **Proposed BACT limit.** | 7. Emissions Method Code: **0** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions:<br>**1-hour maximum: 0.25 lb/MMBtu x 504 MMBtu/hr = 126.1 lb/hr**<br>**Annual average: 0.10 lb/MMBtu x 3,686,281 MMBtu/yr bagasse firing / 2,000 lb/ton = 184.3 TPY**<br>**See PSD Table 2-12 and 2-13 for calculations.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment:<br>**Based on biomass firing.** | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions 1 of 1

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: **OTHER** | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: **0.10 lb/MMBtu, 30-day rolling average.** | 4. Equivalent Allowable Emissions: **126.1** lb/hour **184.3** tons/year |
| 5. Method of Compliance: **Continuous $NO_x$ monitor.** | |
| 6. Allowable Emissions Comment (Description of Operating Method):<br>**Biomass firing 1-hour maximum: 0.25 lb/MMBtu x 504 MMBtu/hr = 126.1 lb/hr**<br>**Annual average: 0.10 lb/MMBtu x 3,686,281 MMBtu/yr bagasse firing/2,000 lb/yr = 184.3 TPY**<br>**See PSD Table 2-12 and 2-13 for calculations.** | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **CO** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **550.2** lb/hour **552.9** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **0.30 lb/MMBtu, 12-month rolling average.**<br>Reference: **Proposed BACT limit.** | 7. Emissions Method Code: **0** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions:<br>**1-hour maximum: 3.0 lb/MMBtu x 183.4 MMBtu/hr = 550.2 lb/hr**<br>**Annual average: 0.30 lb/MMBtu x 3,686,281 MMBtu/yr bagasse firing/2,000 lb/yr = 552.9 TPY**<br>**See PSD Table 2-12 and 2-13 for calculations.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment:<br>**Maximum emissions occur under cold start-up conditions, firing biomass.** | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions 1 of 1

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: **OTHER** | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: **0.30 lb/MMBtu, 12-month rolling average.** | 4. Equivalent Allowable Emissions: **550.2** lb/hour **552.9** tons/year |
| 5. Method of Compliance: **Continuous CO monitor.** | |
| 6. Allowable Emissions Comment (Description of Operating Method): **1-hour maximum: 3.0 lb/MMBtu x 183.4 MMBtu/hr = 550.2 lb/hr** **Annual average: 0.30 lb/MMBtu x 3,686,281 MMBtu/yr bagasse firing/2,000 lb/yr = 552.9 TPY** **See PSD Table 2-12 and 2-13 for calculations.** | |

**Allowable Emissions** Allowable Emissions____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

# F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **VOC** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **8.6** lb/hour **31.3** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **0.017 lb/MMBtu**<br>Reference: **Proposed BACT Limit.** | 7. Emissions Method Code: **0** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions:<br>**0.017 lb/MMBtu x 504 MMBtu/hr = 8.6 lb/hr**<br><br>**Calculations shown in PSD Tables 2-12 and 2-13.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment:<br>**Based on biomass firing.** | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions 1 of 2

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: **OTHER** | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: **0.017 lb/MMBtu** | 4. Equivalent Allowable Emissions: **8.6** lb/hour **31.3** tons/year |
| 5. Method of Compliance: **Annual stack test using EPA Method 25A/18.** | |
| 6. Allowable Emissions Comment (Description of Operating Method): **Hourly based on biomass firing at 504 MMBtu/hr.** **See Tables 2-12 and 2-13 in PSD Report.** | |

**Allowable Emissions** Allowable Emissions 2 of 2

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: **OTHER** | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: **0.0054 lb/MMBtu** | 4. Equivalent Allowable Emissions: **1.34** lb/hour **2.81** tons/year |
| 5. Method of Compliance: **Limit Natural Gas firing to 249 MMBtu/hr.** | |
| 6. Allowable Emissions Comment (Description of Operating Method): **Hourly based on 100% natural gas firing.** **Hourly: 0.0054 lb/MMBtu x 249 MMBtu/hr = 1.34 lb/hr** **Annual: 0.0054 lb/MMBtu/hr x 1,041,553 MMBtu/yr x 1 ton/2,000 lb = 2.81 TPY** | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **Mercury - H114** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **0.0070** lb/hour **0.025** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **$1.38x10^{-5}$ lb/MMBtu for bagasse firing**<br>Reference: **Proposed limit.** | 7. Emissions Method Code: **0** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions:<br>**$1.38x10^{-5}$ lb/MMBtu x 504 MMBtu/hr = 0.0070 lb/hr**<br>**See PSD Tables 2-11 and 2-12 for calculations.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment:<br>**Based on bagasse firing.** | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions 1 of 2

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: **OTHER** | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: **$1.38 \times 10^{-5}$ lb/MMBtu** | 4. Equivalent Allowable Emissions: **0.0070** lb/hour **0.025** tons/year |
| 5. Method of Compliance: **Stack test using EPA Method 29, once every 5 years.** | |
| 6. Allowable Emissions Comment (Description of Operating Method): **Based on bagasse firing. See PSD Tables 2-12 and 2-13.** | |

**Allowable Emissions** Allowable Emissions 2 of 2

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: **OTHER** | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: **$3.6 \times 10^{-6}$ lb/MMBtu** | 4. Equivalent Allowable Emissions: **0.0018** lb/hour **0.024** tons/year |
| 5. Method of Compliance: **Stack test using EPA Method 29, once every 5 years.** | |
| 6. Allowable Emissions Comment (Description of Operating Method): **Based on wood firing. See PSD Tables 2-12 and 2-13.** | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **Pb** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **0.048** lb/hour **0.18** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **$9.6 \times 10^{-5}$ lb/MMBtu for bagasse firing**<br>Reference: **Stack test data.** | 7. Emissions Method Code: **0** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions:<br>**$9.6 \times 10^{-5}$ lb/MMBtu x 504 MMBtu/hr = 0.048 lb/hr**<br>**See PSD Tables 2-12 and 2-13 for calculations.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment:<br>**Based on bagasse firing.** | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **SAM** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **3.46** lb/hour **9.8** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **0.0069 lb/MMBtu, 3-hr avg.**<br>Reference: **Based on 4 % of $SO_2$ emissions.** | 7. Emissions Method Code: **0** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions:<br>**See PSD Tables 2-12 and 2-13 for calculations.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment:<br>**Based on bagasse firing.** | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **FL** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **0.30** lb/hour **1.1** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **$6.0 \times 10^{-4}$ lb/MMBtu for biomass firing** Reference: **See PSD Report, Table 2-12.** | 7. Emissions Method Code: **0** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **$6.0 \times 10^{-4}$ lb/MMBtu x 504 MMBtu/hr = 0.30 lb/hr** **See PSD Tables 2-12 and 2-13 for calculations.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: **Based on biomass firing.** | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **HAPs** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **55.27** lb/hour **18.26** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: Reference: | 7. Emissions Method Code: **5** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **See Tables 2-14 and 2-15 of PSD Report.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **NH3** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **8.8** lb/hour **32.3** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **30 ppmv @ 7% $O_2$ (30-day rolling average)**<br>Reference: **Similar operation** | 7. Emissions Method Code: **0** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |

10. Calculation of Emissions:

**Hourly: $30/10^6$ x 101,300 dscfm x 2,116.8 $lb_f/ft^2$ x 1/(1,545 ft-$lb_f$/lb-mol) x 17 lb/lb-mol x 1/(68+460°R) x 60 min/hr = 8.8 lb/hr**

**See PSD Report, Tables 2-12 and 2-13.**

11. Potential, Fugitive, and Actual Emissions Comment:

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions 1 of 1

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: **OTHER** | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: **30 ppmv @ 7% $O_2$** | 4. Equivalent Allowable Emissions: **8.8** lb/hour **32.3** tons/year |
| 5. Method of Compliance: **Annual stack test.** | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

EMISSIONS UNIT INFORMATION
Section [1]
**Biomass Boiler**

## G. VISIBLE EMISSIONS INFORMATION

**Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.**

**Visible Emissions Limitation:** Visible Emissions Limitation **1** of **2**

| | |
|---|---|
| 1. Visible Emissions Subtype: **VE20** | 2. Basis for Allowable Opacity: ☒ Rule ☐ Other |
| 3. Allowable Opacity:<br>Normal Conditions: **20** % Exceptional Conditions: **27** %<br>Maximum Period of Excess Opacity Allowed: **6** min/hour | |
| 4. Method of Compliance: **Alternative Monitoring Plan (ESP power input), or EPA Method 9.** | |
| 5. Visible Emissions Comment: **40 CFR 60, Subpart Db.** | |

**Visible Emissions Limitation:** Visible Emissions Limitation **2** of **2**

| | |
|---|---|
| 1. Visible Emissions Subtype: **VE40** | 2. Basis for Allowable Opacity: ☐ Rule ☒ Other |
| 3. Allowable Opacity:<br>Normal Conditions: % Exceptional Conditions: **40** %<br>Maximum Period of Excess Opacity Allowed: **60** min/hour | |
| 4. Method of Compliance: **Alternative Monitoring Plan (ESP power input), or EPA Method 9.** | |
| 5. Visible Emissions Comment: **Applies to sootblowing conditions, up to 3 hours per day.** | |

## H. CONTINUOUS MONITOR INFORMATION

**Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.**

**Continuous Monitoring System:** Continuous Monitor **1** of **5**

| | |
|---|---|
| 1. Parameter Code: **ESP Power** | 2. Pollutant(s): |
| 3. CMS Requirement: | ☒ Rule ☐ Other |
| 4. Monitor Information... Manufacturer: Model Number: | Serial Number: |
| 5. Installation Date: | 6. Performance Specification Test Date: |
| 7. Continuous Monitor Comment: **40 CFR 60, Subpart Db. Alternative monitoring plan for opacity: monitor ESP secondary power input.** | |

**Continuous Monitoring System:** Continuous Monitor **2** of **5**

| | |
|---|---|
| 1. Parameter Code: **EM** | 2. Pollutant(s): **NOx** |
| 3. CMS Requirement: | ☐ Rule ☒ Other |
| 4. Monitor Information... Manufacturer: Model Number: | Serial Number: |
| 5. Installation Date: | 6. Performance Specification Test Date: |
| 7. Continuous Monitor Comment: | |

## H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

**Continuous Monitoring System:** Continuous Monitor **3** of **5**

| | |
|---|---|
| 1. Parameter Code: **EM** | 2. Pollutant(s): **SO2** |
| 3. CMS Requirement: | ☐ Rule ☒ Other |
| 4. Monitor Information... Manufacturer: Model Number: | Serial Number: |
| 5. Installation Date: | 6. Performance Specification Test Date: |
| 7. Continuous Monitor Comment: | |

**Continuous Monitoring System:** Continuous Monitor **4** of **5**

| | |
|---|---|
| 1. Parameter Code: **EM** | 2. Pollutant(s): **CO** |
| 3. CMS Requirement: | ☐ Rule ☒ Other |
| 4. Monitor Information... Manufacturer: Model Number: | Serial Number: |
| 5. Installation Date: | 6. Performance Specification Test Date: |
| 7. Continuous Monitor Comment: | |

## H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

**Continuous Monitoring System:** Continuous Monitor **5** of **5**

| | |
|---|---|
| 1. Parameter Code: **O2** | 2. Pollutant(s): **Oxygen** |
| 3. CMS Requirement: | ☐ Rule ☒ Other |
| 4. Monitor Information... Manufacturer: Model Number: | Serial Number: |
| 5. Installation Date: | 6. Performance Specification Test Date: |
| 7. Continuous Monitor Comment: | |

**Continuous Monitoring System:** Continuous Monitor ____ of ____

| | |
|---|---|
| 1. Parameter Code: | 2. Pollutant(s): |
| 3. CMS Requirement: | ☐ Rule ☐ Other |
| 4. Monitor Information... Manufacturer: Model Number: | Serial Number: |
| 5. Installation Date: | 6. Performance Specification Test Date: |
| 7. Continuous Monitor Comment: | |

# I. EMISSIONS UNIT ADDITIONAL INFORMATION

## Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **PSD Report** ☐ Previously Submitted, Date ____________

2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **PSD Report** ☐ Previously Submitted, Date ____________

3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **PSD Report** ☐ Previously Submitted, Date ____________

4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **PSD Report** ☐ Previously Submitted, Date ____________
   ☐ Not Applicable (construction application)

5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ____________ ☐ Previously Submitted, Date ____________
   ☒ Not Applicable

6. Compliance Demonstration Reports/Records:
   ☐ Attached, Document ID: ____________
   Test Date(s)/Pollutant(s) Tested: ____________________________

   ☐ Previously Submitted, Date: ________
   Test Date(s)/Pollutant(s) Tested: ____________________________

   ☐ To be Submitted, Date (if known): ____________
   Test Date(s)/Pollutant(s) Tested: ____________________________

   ☒ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute:
   ☒ Attached, Document ID: **PSD Report** ☐ Not Applicable

EMISSIONS UNIT INFORMATION
Section [1]
**Biomass Boiler**

## I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

**Additional Requirements for Air Construction Permit Applications**

| | |
|---|---|
| 1. | Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)):<br>☒ Attached, Document ID: **PSD Report** ☐ Not Applicable |
| 2. | Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.):<br>☒ Attached, Document ID: **PSD Report** ☐ Not Applicable |
| 3. | Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only)<br>☐ Attached, Document ID: ________ ☒ Not Applicable |

**Additional Requirements for Title V Air Operation Permit Applications**

| | |
|---|---|
| 1. | Identification of Applicable Requirements:<br>☐ Attached, Document ID: ________ |
| 2. | Compliance Assurance Monitoring:<br>☐ Attached, Document ID: ________ ☐ Not Applicable |
| 3. | Alternative Methods of Operation:<br>☐ Attached, Document ID: ________ ☐ Not Applicable |
| 4. | Alternative Modes of Operation (Emissions Trading):<br>☐ Attached, Document ID: ________ ☐ Not Applicable |

**Additional Requirements Comment**

| |
|---|
| |

## III. EMISSIONS UNIT INFORMATION

**Title V Air Operation Permit Application** - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for an initial, revised or renewal Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

**Air Construction Permit or FESOP Application** - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for an air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

**Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application** – Where this application is used to apply for both an air construction permit and a revised or renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes, and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this application that is subject to air construction permitting and for each such emissions unit that is a regulated or unregulated unit for purposes of Title V permitting. (An emissions unit may be exempt from air construction permitting but still be classified as an unregulated unit for Title V purposes.) Emissions units classified as insignificant for Title V purposes are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

## A. GENERAL EMISSIONS UNIT INFORMATION

**Title V Air Operation Permit Emissions Unit Classification**

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

**Emissions Unit Description and Status**

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
   **Ethanol Production Process**

3. Emissions Unit Identification Number:

| 4. Emissions Unit Status Code: | 5. Commence Construction Date: | 6. Initial Startup Date: | 7. Emissions Unit Major Group SIC Code: |
|---|---|---|---|
| **C** | | | **28** |

8. Federal Program Applicability: (Check all that apply)

   ☐ Acid Rain Unit

   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:
    **Includes Extraction, Evaporation, Fermentation, Distillation, and Dehydration processes.**

**Emissions Unit Control Equipment/Method:** Control 1 of 1

| | |
|---|---|
| 1. Control Equipment/Method Description: **Wet Scrubbers (2)** | |
| 2. Control Device or Method Code: **141** | |

**Emissions Unit Control Equipment/Method:** Control ____ of ____

| | |
|---|---|
| 1. Control Equipment/Method Description: | |
| 2. Control Device or Method Code: | |

**Emissions Unit Control Equipment/Method:** Control ____ of ____

| | |
|---|---|
| 1. Control Equipment/Method Description: | |
| 2. Control Device or Method Code: | |

**Emissions Unit Control Equipment/Method:** Control ____ of ____

| | |
|---|---|
| 1. Control Equipment/Method Description: | |
| 2. Control Device or Method Code: | |

## B. EMISSIONS UNIT CAPACITY INFORMATION
### (Optional for unregulated emissions units.)

**Emissions Unit Operating Capacity and Schedule**

| | |
|---|---|
| 1. Maximum Process or Throughput Rate: | |
| 2. Maximum Production Rate: **120,000 gal/day ethanol** | |
| 3. Maximum Heat Input Rate: million Btu/hr | |
| 4. Maximum Incineration Rate: pounds/hr<br>tons/day | |
| 5. Requested Maximum Operating Schedule:<br>**24** hours/day<br>**44** weeks/year | **7** days/week<br>**7,296** hours/year |
| 6. Operating Capacity/Schedule Comment:<br>**Maximum daily ethanol production rate is 120,000 gal/day.**<br>**Maximum annual ethanol production rate is 36,000,000 gal/yr.**<br>**See PSD Tables 2-10 and 2-11.** | |

EMISSIONS UNIT INFORMATION
Section [2]
**Ethanol Production Process**

## C. EMISSION POINT (STACK/VENT) INFORMATION
### (Optional for unregulated emissions units.)

**Emission Point Description and Type**

| | |
|---|---|
| 1. Identification of Point on Plot Plan or Flow Diagram: **Ethanol Production** | 2. Emission Point Type Code: **3** |
| 3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **Fermentation – wet scrubber stack**<br>**Distillation – wet scrubber stack** | |
| 4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: | |

| | | |
|---|---|---|
| 5. Discharge Type Code: **V** | 6. Stack Height: **25** feet | 7. Exit Diameter: **4.9** feet |
| 8. Exit Temperature: **70**°F | 9. Actual Volumetric Flow Rate: **4,223** acfm | 10. Water Vapor: % |

| | |
|---|---|
| 11. Maximum Dry Standard Flow Rate: dscfm | 12. Nonstack Emission Point Height: feet |
| 13. Emission Point UTM Coordinates...<br>Zone: East (km):<br>North (km): | 14. Emission Point Latitude/Longitude...<br>Latitude (DD/MM/SS)<br>Longitude (DD/MM/SS) |

15. Emission Point Comment:
**Stack data for fermentation area wet scrubber.**
**See PSD Report for parameters for distillation area wet scrubber.**

## D. SEGMENT (PROCESS/FUEL) INFORMATION

**Segment Description and Rate:** Segment 1 of 1

| | | |
|---|---|---|
| 1. Segment Description (Process/Fuel Type): **Industrial processes; chemical manufacturing; methanol/alcohol production; ethanol by fermentation** | | |
| 2. Source Classification Code (SCC): **3-01-250-10** | 3. SCC Units: **Tons** | |
| 4. Maximum Hourly Rate: **16.46** | 5. Maximum Annual Rate: **118,530** | 6. Estimated Annual Activity Factor: |
| 7. Maximum % Sulfur: | 8. Maximum % Ash: | 9. Million Btu per SCC Unit: |
| 10. Segment Comment: **Segment represents overall ethanol production process. Maximum hourly rate are based on 120,000 gal/day x 1 day / 24 hours x 6.585 lb ethanol/gallon ethanol / 2,000 lb/ton = 16.46 tons/hr of ethanol. Maximum annual rate based on 36,000,000 gal/yr x 6.585 lb ethanol/gallon ethanol / 2,000 lb/ton = 118,530 tons/yr ethanol.** | | |

**Segment Description and Rate:** Segment _____ of _____

| | | |
|---|---|---|
| 1. Segment Description (Process/Fuel Type): | | |
| 2. Source Classification Code (SCC): | 3. SCC Units: | |
| 4. Maximum Hourly Rate: | 5. Maximum Annual Rate: | 6. Estimated Annual Activity Factor: |
| 7. Maximum % Sulfur: | 8. Maximum % Ash: | 9. Million Btu per SCC Unit: |
| 10. Segment Comment: | | |

## E. EMISSIONS UNIT POLLUTANTS

**List of Pollutants Emitted by Emissions Unit**

| 1. Pollutant Emitted | 2. Primary Control Device Code | 3. Secondary Control Device Code | 4. Pollutant Regulatory Code |
|---|---|---|---|
| VOC | 141 | | WP |
| Total HAPs | 141 | | WP |
| | | | |
| | | | |
| | | | |
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| | | | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>**

| | |
|---|---|
| 1. Pollutant Emitted: **VOCs** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **21.8** lb/hour **79.5** tons/year | 4. Synthetically Limited? ☐ Yes ☒ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: Reference: | 7. Emissions Method Code: **3** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions:<br>**Refer to PSD Tables 2-10 and 2-11 for the calculation of emissions.**<br>**Fermentation scrubber: 19.01 lb/hr; 69.34 TPY**<br>**Distillation scrubber: 2.78 lb/hr; 10.16 TPY** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>**

| | |
|---|---|
| 1. Pollutant Emitted: **HAPs** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **1.05** lb/hour **3.85** tons/year | 4. Synthetically Limited? ☐ Yes ☒ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: Reference: | 7. Emissions Method Code: **3** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **Refer to PSD Tables 2-10 and 2-11 for the calculation of emissions.** **Fermentation scrubber: 0.79 lb/hr; 2.89 TPY** **Distillation scrubber: 0.26 lb/hr; 0.96 TPY** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## G. VISIBLE EMISSIONS INFORMATION

**Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.**

**Visible Emissions Limitation:** Visible Emissions Limitation _____ of _____

| | |
|---|---|
| 1. Visible Emissions Subtype: | 2. Basis for Allowable Opacity:<br>☐ Rule ☐ Other |
| 3. Allowable Opacity:<br>Normal Conditions: % Exceptional Conditions: %<br>Maximum Period of Excess Opacity Allowed: min/hour | |
| 4. Method of Compliance: | |
| 5. Visible Emissions Comment: | |

**Visible Emissions Limitation:** Visible Emissions Limitation _____ of _____

| | |
|---|---|
| 1. Visible Emissions Subtype: | 2. Basis for Allowable Opacity:<br>☐ Rule ☐ Other |
| 3. Allowable Opacity:<br>Normal Conditions: % Exceptional Conditions: %<br>Maximum Period of Excess Opacity Allowed: min/hour | |
| 4. Method of Compliance: | |
| 5. Visible Emissions Comment: | |

## H. CONTINUOUS MONITOR INFORMATION

**Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.**

**Continuous Monitoring System:** Continuous Monitor ____ of ____

| | |
|---|---|
| 1. Parameter Code: | 2. Pollutant(s): |
| 3. CMS Requirement: | ☐ Rule ☐ Other |
| 4. Monitor Information...<br>Manufacturer:<br>Model Number: | Serial Number: |
| 5. Installation Date: | 6. Performance Specification Test Date: |
| 7. Continuous Monitor Comment: | |

**Continuous Monitoring System:** Continuous Monitor ____ of ____

| | |
|---|---|
| 1. Parameter Code: | 2. Pollutant(s): |
| 3. CMS Requirement: | ☐ Rule ☐ Other |
| 4. Monitor Information...<br>Manufacturer:<br>Model Number: | Serial Number: |
| 5. Installation Date: | 6. Performance Specification Test Date: |
| 7. Continuous Monitor Comment: | |

**EMISSIONS UNIT INFORMATION**
**Section [2]**
**Ethanol Production Process**

## I. EMISSIONS UNIT ADDITIONAL INFORMATION

**Additional Requirements for All Applications, Except as Otherwise Stated**

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☒ Attached, Document ID: **PSD Report** ☐ Previously Submitted, Date ____

2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____

3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☒ Attached, Document ID: **PSD Report** ☐ Previously Submitted, Date ____

4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____
☒ Not Applicable (construction application)

5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____
☒ Not Applicable

6. Compliance Demonstration Reports/Records:
☐ Attached, Document ID: ____
Test Date(s)/Pollutant(s) Tested: ____
☐ Previously Submitted, Date: ____
Test Date(s)/Pollutant(s) Tested: ____
☐ To be Submitted, Date (if known): ____
Test Date(s)/Pollutant(s) Tested: ____
☒ Not Applicable
Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute:
☒ Attached, Document ID: **PSD Report** ☐ Not Applicable

## I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

**Additional Requirements for Air Construction Permit Applications**

| | |
|---|---|
| 1. | Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)):<br>☒ Attached, Document ID: PSD Report ☐ Not Applicable |
| 2. | Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.):<br>☐ Attached, Document ID: ____ ☒ Not Applicable |
| 3. | Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only)<br>☐ Attached, Document ID: ____ ☒ Not Applicable |

**Additional Requirements for Title V Air Operation Permit Applications**

| | |
|---|---|
| 1. | Identification of Applicable Requirements:<br>☐ Attached, Document ID: ____ |
| 2. | Compliance Assurance Monitoring:<br>☐ Attached, Document ID: ____ ☐ Not Applicable |
| 3. | Alternative Methods of Operation:<br>☐ Attached, Document ID: ____ ☐ Not Applicable |
| 4. | Alternative Modes of Operation (Emissions Trading):<br>☐ Attached, Document ID: ____ ☐ Not Applicable |

**Additional Requirements Comment**

| |
|---|
| |

# III. EMISSIONS UNIT INFORMATION

**Title V Air Operation Permit Application** - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for an initial, revised or renewal Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

**Air Construction Permit or FESOP Application** - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for an air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

**Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application** – Where this application is used to apply for both an air construction permit and a revised or renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes, and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this application that is subject to air construction permitting and for each such emissions unit that is a regulated or unregulated unit for purposes of Title V permitting. (An emissions unit may be exempt from air construction permitting but still be classified as an unregulated unit for Title V purposes.) Emissions units classified as insignificant for Title V purposes are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

## A. GENERAL EMISSIONS UNIT INFORMATION

**Title V Air Operation Permit Emissions Unit Classification**

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

**Emissions Unit Description and Status**

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
   **Biomass and Ash Handling System**

3. Emissions Unit Identification Number:

| 4. Emissions Unit Status Code: | 5. Commence Construction Date: | 6. Initial Startup Date: | 7. Emissions Unit Major Group SIC Code: |
|---|---|---|---|
| **C** | | | **49** |

8. Federal Program Applicability: (Check all that apply)

   ☐ Acid Rain Unit

   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:
   **Includes storage piles, transfer operations, conveyors, screens, crushers, hoppers, and silos associated with bagasse, wood, and ash handling and storage operations. In addition, truck traffic from biomass handling and product load out are included in this emissions unit.**

**Emissions Unit Control Equipment/Method:** Control 1 of 1

| | |
|---|---|
| 1. Control Equipment/Method Description: **Enclosures** | |
| 2. Control Device or Method Code: **054** | |

**Emissions Unit Control Equipment/Method:** Control ____ of ____

| | |
|---|---|
| 1. Control Equipment/Method Description: | |
| 2. Control Device or Method Code: | |

**Emissions Unit Control Equipment/Method:** Control ____ of ____

| | |
|---|---|
| 1. Control Equipment/Method Description: | |
| 2. Control Device or Method Code: | |

**Emissions Unit Control Equipment/Method:** Control ____ of ____

| | |
|---|---|
| 1. Control Equipment/Method Description: | |
| 2. Control Device or Method Code: | |

## B. EMISSIONS UNIT CAPACITY INFORMATION
### (Optional for unregulated emissions units.)

**Emissions Unit Operating Capacity and Schedule**

| | |
|---|---|
| 1. Maximum Process or Throughput Rate: **515,579 TPY** | |
| 2. Maximum Production Rate: | |
| 3. Maximum Heat Input Rate: million Btu/hr | |
| 4. Maximum Incineration Rate: pounds/hr<br>tons/day | |
| 5. Requested Maximum Operating Schedule:<br>**24** hours/day<br>**52** weeks/year | <br>**7** days/week<br>**8,760** hours/year |
| 6. Operating Capacity/Schedule Comment:<br><br>**Worst-case scenario is the 10% wood scenario. Biomass handling for this scenario includes 43,368 TPY wood; 425,340 TPY bagasse; plus a 10% safety factor for a total of 515,579 TPY. See PSD Table 2-16.** | |

## C. EMISSION POINT (STACK/VENT) INFORMATION

**(Optional for unregulated emissions units.)**

**Emission Point Description and Type**

| | |
|---|---|
| 1. Identification of Point on Plot Plan or Flow Diagram: **Biomass Handling System** | 2. Emission Point Type Code: **4** |

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:
**Conveyor Transfer Points**
**Hogger**
**Biomass Storage Piles**
**Truck Traffic**

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

| | | |
|---|---|---|
| 5. Discharge Type Code: **F** | 6. Stack Height: feet | 7. Exit Diameter: Feet |
| 8. Exit Temperature: °F | 9. Actual Volumetric Flow Rate: acfm | 10. Water Vapor: % |

| | |
|---|---|
| 11. Maximum Dry Standard Flow Rate: dscfm | 12. Nonstack Emission Point Height: Feet |
| 13. Emission Point UTM Coordinates... Zone: East (km): North (km): | 14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS) |

15. Emission Point Comment:
**Fugitive emissions from the Biomass Handling System and storage piles.**

## D. SEGMENT (PROCESS/FUEL) INFORMATION

**Segment Description and Rate:** Segment 1 of 1

| | | |
|---|---|---|
| 1. Segment Description (Process/Fuel Type): **Bulk materials open stockpiles; Biomass** | | |
| 2. Source Classification Code (SCC): **3-02-103-99** | 3. SCC Units: **Tons Used** | |
| 4. Maximum Hourly Rate: | 5. Maximum Annual Rate: **515,579** | 6. Estimated Annual Activity Factor: |
| 7. Maximum % Sulfur: | 8. Maximum % Ash: | 9. Million Btu per SCC Unit: |
| 10. Segment Comment: **Segment represents biomass handling and storage operations.** | | |

**Segment Description and Rate:** Segment _____ of _____

| | | |
|---|---|---|
| 1. Segment Description (Process/Fuel Type): | | |
| 2. Source Classification Code (SCC): | 3. SCC Units: | |
| 4. Maximum Hourly Rate: | 5. Maximum Annual Rate: | 6. Estimated Annual Activity Factor: |
| 7. Maximum % Sulfur: | 8. Maximum % Ash: | 9. Million Btu per SCC Unit: |
| 10. Segment Comment: | | |

## E. EMISSIONS UNIT POLLUTANTS

**List of Pollutants Emitted by Emissions Unit**

| 1. Pollutant Emitted | 2. Primary Control Device Code | 3. Secondary Control Device Code | 4. Pollutant Regulatory Code |
|---|---|---|---|
| PM | | | WP |
| PM10 | | | WP |
| PM2.5 | | | WP |
| | | | |
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## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **PM** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **2.85** lb/hour **7.9** tons/year | 4. Synthetically Limited? ☐ Yes ☒ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor:<br><br>Reference: | 7. Emissions Method Code: **3** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions:<br>**Refer to PSD Table 2-16 and Table C-5 in Appendix C for the calculation of emissions.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **PM10** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **0.83** lb/hour **1.8** tons/year | 4. Synthetically Limited? ☐ Yes ☒ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: <br>Reference: | 7. Emissions Method Code: **3** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **Refer to PSD Table 2-16 and Table C-5 in Appendix C for the calculation of emissions.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **PM2.5** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **0.35** lb/hour **0.33** tons/year | 4. Synthetically Limited? ☐ Yes ☒ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: <br> Reference: | 7. Emissions Method Code: **3** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **Refer to PSD Table 2-16 and Table C-5 in Appendix C for the calculation of emissions.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## G. VISIBLE EMISSIONS INFORMATION

**Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.**

**Visible Emissions Limitation:** Visible Emissions Limitation 1 of 1

| | |
|---|---|
| 1. Visible Emissions Subtype: **VE20** | 2. Basis for Allowable Opacity: ☒ Rule ☐ Other |
| 3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **27** % Maximum Period of Excess Opacity Allowed: **6** min/hour | |
| 4. Method of Compliance: **EPA Method 9.** | |
| 5. Visible Emissions Comment: **Rule 62-296.320(4)(b), F.A.C.** | |

## H. CONTINUOUS MONITOR INFORMATION

**Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.**

**Continuous Monitoring System:** Continuous Monitor ____ of ____

| | |
|---|---|
| 1. Parameter Code: | 2. Pollutant(s): |
| 3. CMS Requirement: | ☐ Rule ☐ Other |
| 4. Monitor Information...<br>Manufacturer:<br>Model Number: | Serial Number: |
| 5. Installation Date: | 6. Performance Specification Test Date: |
| 7. Continuous Monitor Comment: | |

**Continuous Monitoring System:** Continuous Monitor ____ of ____

| | |
|---|---|
| 1. Parameter Code: | 2. Pollutant(s): |
| 3. CMS Requirement: | ☐ Rule ☐ Other |
| 4. Monitor Information...<br>Manufacturer:<br>Model Number: | Serial Number: |
| 5. Installation Date: | 6. Performance Specification Test Date: |
| 7. Continuous Monitor Comment: | |

## I. EMISSIONS UNIT ADDITIONAL INFORMATION

**Additional Requirements for All Applications, Except as Otherwise Stated**

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **PSD Report** ☐ Previously Submitted, Date ____

2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____

3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **PSD Report** ☐ Previously Submitted, Date ____

4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____
   ☒ Not Applicable (construction application)

5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____
   ☒ Not Applicable

6. Compliance Demonstration Reports/Records:
   ☐ Attached, Document ID: ____
   Test Date(s)/Pollutant(s) Tested: ____

   ☐ Previously Submitted, Date: ____
   Test Date(s)/Pollutant(s) Tested: ____

   ☐ To be Submitted, Date (if known): ____
   Test Date(s)/Pollutant(s) Tested: ____

   ☒ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute:
   ☐ Attached, Document ID: ____ ☐ Not Applicable

## I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

**Additional Requirements for Air Construction Permit Applications**

| | |
|---|---|
| 1. | Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)):<br>☒ Attached, Document ID: **PSD Report** ☐ Not Applicable |
| 2. | Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.):<br>☐ Attached, Document ID: ____ ☒ Not Applicable |
| 3. | Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only)<br>☐ Attached, Document ID: ____ ☒ Not Applicable |

**Additional Requirements for Title V Air Operation Permit Applications**

| | |
|---|---|
| 1. | Identification of Applicable Requirements:<br>☐ Attached, Document ID: ____ |
| 2. | Compliance Assurance Monitoring:<br>☐ Attached, Document ID: ____ ☐ Not Applicable |
| 3. | Alternative Methods of Operation:<br>☐ Attached, Document ID: ____ ☐ Not Applicable |
| 4. | Alternative Modes of Operation (Emissions Trading):<br>☐ Attached, Document ID: ____ ☐ Not Applicable |

**Additional Requirements Comment**

# III. EMISSIONS UNIT INFORMATION

**Title V Air Operation Permit Application** - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for an initial, revised or renewal Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

**Air Construction Permit or FESOP Application** - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for an air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

**Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application** – Where this application is used to apply for both an air construction permit and a revised or renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes, and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this application that is subject to air construction permitting and for each such emissions unit that is a regulated or unregulated unit for purposes of Title V permitting. (An emissions unit may be exempt from air construction permitting but still be classified as an unregulated unit for Title V purposes.) Emissions units classified as insignificant for Title V purposes are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

## A. GENERAL EMISSIONS UNIT INFORMATION

**Title V Air Operation Permit Emissions Unit Classification**

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

**Emissions Unit Description and Status**

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
   **Product Load Out**

3. Emissions Unit Identification Number:

| 4. Emissions Unit Status Code: | 5. Commence Construction Date: | 6. Initial Startup Date: | 7. Emissions Unit Major Group SIC Code: |
|---|---|---|---|
| **C** | | | **28** |

8. Federal Program Applicability: (Check all that apply)

   ☐ Acid Rain Unit

   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:
    **Fuel ethanol or blended ethanol is loaded onto trucks or railcars. VOC emission controlled by a flare.**

**Emissions Unit Control Equipment/Method:** Control 1 of 1

| | |
|---|---|
| 1. Control Equipment/Method Description: **Flare** | |
| 2. Control Device or Method Code: **023** | |

**Emissions Unit Control Equipment/Method:** Control ____ of ____

| | |
|---|---|
| 1. Control Equipment/Method Description: | |
| 2. Control Device or Method Code: | |

**Emissions Unit Control Equipment/Method:** Control ____ of ____

| | |
|---|---|
| 1. Control Equipment/Method Description: | |
| 2. Control Device or Method Code: | |

**Emissions Unit Control Equipment/Method:** Control ____ of ____

| | |
|---|---|
| 1. Control Equipment/Method Description: | |
| 2. Control Device or Method Code: | |

## B. EMISSIONS UNIT CAPACITY INFORMATION
### (Optional for unregulated emissions units.)

**Emissions Unit Operating Capacity and Schedule**

| | |
|---|---|
| 1. Maximum Process or Throughput Rate: **37,620,000 gal/yr** | |
| 2. Maximum Production Rate: | |
| 3. Maximum Heat Input Rate: million Btu/hr | |
| 4. Maximum Incineration Rate: pounds/hr<br>tons/day | |
| 5. Requested Maximum Operating Schedule:<br>**24** hours/day<br>**52** weeks/year | <br>**7** days/week<br>**3,120** hours/year |
| 6. Operating Capacity/Schedule Comment:<br>**Maximum throughput rate is based on a maximum of 37,620,000 gal/yr of ethanol plus denaturant/gasoline. See PSD Table 2-18.** | |

## C. EMISSION POINT (STACK/VENT) INFORMATION
### (Optional for unregulated emissions units.)

**Emission Point Description and Type**

| | |
|---|---|
| 1. Identification of Point on Plot Plan or Flow Diagram: **Product Load Out** | 2. Emission Point Type Code: **1** |
| 3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **This unit consists of a truck loading area and flare.** | |
| 4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: | |

| | | |
|---|---|---|
| 5. Discharge Type Code: **F** | 6. Stack Height: **30** feet | 7. Exit Diameter: **1.0** Feet |
| 8. Exit Temperature: **1,500**°F | 9. Actual Volumetric Flow Rate: acfm | 10. Water Vapor: % |

| | |
|---|---|
| 11. Maximum Dry Standard Flow Rate: Dscfm | 12. Nonstack Emission Point Height: Feet |
| 13. Emission Point UTM Coordinates... Zone: East (km): North (km): | 14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS) |
| 15. Emission Point Comment: **See PSD report Table 2-18 for a detailed description of the flare.** | |

## D. SEGMENT (PROCESS/FUEL) INFORMATION

**Segment Description and Rate:** Segment 1 of 1

| | | |
|---|---|---|
| 1. Segment Description (Process/Fuel Type):<br>**Petroleum and Solvent Evaporation; Organic Chemical Transportation; Specific Liquid; Cars/Trucks: Loading Rack** | | |
| 2. Source Classification Code (SCC):<br>**4-08-999-95** | 3. SCC Units:<br>**1,000 Gallons** | |
| 4. Maximum Hourly Rate:<br>**36** | 5. Maximum Annual Rate:<br>**37,620** | 6. Estimated Annual Activity Factor: |
| 7. Maximum % Sulfur: | 8. Maximum % Ash: | 9. Million Btu per SCC Unit: |
| 10. Segment Comment:<br>**See PSD report Table 2-18 for calculation.** | | |

**Segment Description and Rate:** Segment _ of _

| | | |
|---|---|---|
| 1. Segment Description (Process/Fuel Type): | | |
| 2. Source Classification Code (SCC): | 3. SCC Units: | |
| 4. Maximum Hourly Rate: | 5. Maximum Annual Rate: | 6. Estimated Annual Activity Factor: |
| 7. Maximum % Sulfur: | 8. Maximum % Ash: | 9. Million Btu per SCC Unit: |
| 10. Segment Comment: | | |

## E. EMISSIONS UNIT POLLUTANTS

**List of Pollutants Emitted by Emissions Unit**

| 1. Pollutant Emitted | 2. Primary Control Device Code | 3. Secondary Control Device Code | 4. Pollutant Regulatory Code |
|---|---|---|---|
| SO2 | 023 | | NS |
| NOx | 023 | | NS |
| CO | 023 | | NS |
| PM | 023 | | NS |
| PM10 | 023 | | NS |
| PM2.5 | 023 | | NS |
| VOC | 023 | | WP |
| Total HAPs | 023 | | WP |
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## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS
(Optional for unregulated emissions units.)

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **SO2** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **0.0057** lb/hour **0.0090** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **0.00059 lb/MMBtu**<br>Reference: **AP-42, Table 1.4-2** | 7. Emissions Method Code: **3** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **Refer to PSD Table 2-18.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **NOx** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **0.66** lb/hour **1.04** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **0.068 lb/MMBtu**<br>Reference: **AP-42, Table 13.5-1** | 7. Emissions Method Code: **3** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **Refer to PSD Table 2-18.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **CO** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **3.61** lb/hour **5.64** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **0.37 lb/MMBtu**<br>Reference: **AP-42, Table 13.5-1** | 7. Emissions Method Code: **3** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **Refer to PSD Table 2-18.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **PM** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **0.034** lb/hour **0.052** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **0.0034 lb/MMBtu**<br>Reference: **AP-42, Table 13.5-1** | 7. Emissions Method Code: **3** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **Refer to PSD Table 2-18.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **PM10** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **0.034** lb/hour **0.052** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **0.0034 lb/MMBtu**<br>Reference: **AP-42, Table 13.5-1** | 7. Emissions Method Code: **3** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **Refer to PSD Table 2-18.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **PM2.5** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **0.034** lb/hour **0.052** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **0.0034 lb/MMBtu**<br>Reference: **AP-42, Table 13.5-1** | 7. Emissions Method Code: **3** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **Refer to PSD Table 2-18.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **VOC** | 2. Total Percent Efficiency of Control: **98** |
| 3. Potential Emissions: **10.64** lb/hour **6.98** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **Refer to PSD Table 2-18.**<br>Reference: **Refer to PSD Table 2-18.** | 7. Emissions Method Code: **3** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **Refer to PSD Table 2-18.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **HAPs** | 2. Total Percent Efficiency of Control: **98** |
| 3. Potential Emissions: **0.34** lb/hour **0.22** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: <br>Reference: | 7. Emissions Method Code: **3** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **Refer to PSD Table 2-19.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## G. VISIBLE EMISSIONS INFORMATION

**Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.**

**Visible Emissions Limitation:** Visible Emissions Limitation 1 of 1

| | |
|---|---|
| 1. Visible Emissions Subtype:<br>**VE0** | 2. Basis for Allowable Opacity:<br>☒ Rule ☐ Other |
| 3. Allowable Opacity:<br>Normal Conditions: **0**% Exceptional Conditions: %<br>Maximum Period of Excess Opacity Allowed: **5** min/hour | |
| 4. Method of Compliance:<br>**EPA Method 9** | |
| 5. Visible Emissions Comment:<br>**Based on 40 CFR 60.18 (a)(1).** | |

## H. CONTINUOUS MONITOR INFORMATION

**Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.**

**Continuous Monitoring System:** Continuous Monitor ____ of ____

| | |
|---|---|
| 1. Parameter Code: | 2. Pollutant(s): |
| 3. CMS Requirement: | ☐ Rule ☐ Other |
| 4. Monitor Information...<br>Manufacturer:<br>Model Number: | <br><br>Serial Number: |
| 5. Installation Date: | 6. Performance Specification Test Date: |
| 7. Continuous Monitor Comment: | |

**Continuous Monitoring System:** Continuous Monitor ____ of ____

| | |
|---|---|
| 1. Parameter Code: | 2. Pollutant(s): |
| 3. CMS Requirement: | ☐ Rule ☐ Other |
| 4. Monitor Information...<br>Manufacturer:<br>Model Number: | <br><br>Serial Number: |
| 5. Installation Date: | 6. Performance Specification Test Date: |
| 7. Continuous Monitor Comment: | |

# I. EMISSIONS UNIT ADDITIONAL INFORMATION

**Additional Requirements for All Applications, Except as Otherwise Stated**

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☒ Attached, Document ID: **PSD Report** ☐ Previously Submitted, Date ___________

2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: __________ ☐ Previously Submitted, Date ___________

3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☒ Attached, Document ID: **PSD Report** ☐ Previously Submitted, Date ___________

4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: __________ ☐ Previously Submitted, Date ___________
☒ Not Applicable (construction application)

5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: __________ ☐ Previously Submitted, Date ___________
☒ Not Applicable

6. Compliance Demonstration Reports/Records:
☐ Attached, Document ID: __________
Test Date(s)/Pollutant(s) Tested: ____________________________________________

☐ Previously Submitted, Date: _______
Test Date(s)/Pollutant(s) Tested: ____________________________________________

☐ To be Submitted, Date (if known): __________
Test Date(s)/Pollutant(s) Tested: ____________________________________________

☒ Not Applicable
Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute:
☐ Attached, Document ID: __________ ☒ Not Applicable

## I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

**Additional Requirements for Air Construction Permit Applications**

| | |
|---|---|
| 1. | Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)):<br>☐ Attached, Document ID: _ ☒ Not Applicable |
| 2. | Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.):<br>☐ Attached, Document ID: ___________ ☒ Not Applicable |
| 3. | Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only)<br>☐ Attached, Document ID: ___________ ☒ Not Applicable |

**Additional Requirements for Title V Air Operation Permit Applications**

| | |
|---|---|
| 1. | Identification of Applicable Requirements:<br>☐ Attached, Document ID: ___________ |
| 2. | Compliance Assurance Monitoring:<br>☐ Attached, Document ID: __________ ☐ Not Applicable |
| 3. | Alternative Methods of Operation:<br>☐ Attached, Document ID: __________ ☐ Not Applicable |
| 4. | Alternative Modes of Operation (Emissions Trading):<br>☐ Attached, Document ID: __________ ☐ Not Applicable |

**Additional Requirements Comment**

| |
|---|
| |

# III. EMISSIONS UNIT INFORMATION

**Title V Air Operation Permit Application** - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for an initial, revised or renewal Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

**Air Construction Permit or FESOP Application** - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for an air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

**Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application** – Where this application is used to apply for both an air construction permit and a revised or renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes, and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this application that is subject to air construction permitting and for each such emissions unit that is a regulated or unregulated unit for purposes of Title V permitting. (An emissions unit may be exempt from air construction permitting but still be classified as an unregulated unit for Title V purposes.) Emissions units classified as insignificant for Title V purposes are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

## A. GENERAL EMISSIONS UNIT INFORMATION

**Title V Air Operation Permit Emissions Unit Classification**

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

**Emissions Unit Description and Status**

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
   **NSPS Storage Tanks**

3. Emissions Unit Identification Number:

| 4. Emissions Unit Status Code: | 5. Commence Construction Date: | 6. Initial Startup Date: | 7. Emissions Unit Major Group SIC Code: |
|---|---|---|---|
| **C** | | | **28** |

8. Federal Program Applicability: (Check all that apply)

   ☐ Acid Rain Unit

   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:
    **Includes the Fuel Ethanol Storage Tank, 200 Proof Storage Tank, Off-Spec Tank, and Denaturant/Gasoline Tank. These tanks are regulated under NSPS Subpart Kb.**

**Emissions Unit Control Equipment/Method:** Control 1 of 1

| | |
|---|---|
| 1. Control Equipment/Method Description: **Internal Floating Roofs - for all** | |
| 2. Control Device or Method Code: **091** | |

**Emissions Unit Control Equipment/Method:** Control ____ of ____

| | |
|---|---|
| 1. Control Equipment/Method Description: | |
| 2. Control Device or Method Code: | |

**Emissions Unit Control Equipment/Method:** Control ____ of ____

| | |
|---|---|
| 1. Control Equipment/Method Description: | |
| 2. Control Device or Method Code: | |

**Emissions Unit Control Equipment/Method:** Control ____ of ____

| | |
|---|---|
| 1. Control Equipment/Method Description: | |
| 2. Control Device or Method Code: | |

## B. EMISSIONS UNIT CAPACITY INFORMATION
## (Optional for unregulated emissions units.)

**Emissions Unit Operating Capacity and Schedule**

| | |
|---|---|
| 1. Maximum Process or Throughput Rate:<br>**36,000,000 gal/yr – Ethanol/Denaturant/Gasoline** | |
| 2. Maximum Production Rate: **120,000 gal/day - Ethanol** | |
| 3. Maximum Heat Input Rate: million Btu/hr | |
| 4. Maximum Incineration Rate: pounds/hr<br>tons/day | |
| 5. Requested Maximum Operating Schedule:<br>**24** hours/day<br>**52** weeks/year | <br>**7** days/week<br>**8,760** hours/year |
| 6. Operating Capacity/Schedule Comment:<br><br>**Maximum daily ethanol production rate is 120,000 gal/day.**<br>**Maximum annual ethanol production rate is 36,000,000 gal/yr, and denaturant/gasoline throughput is 1,620,000 gal/yr.**<br>**Throughput rates for each tank varies, see PSD Table 2-4 and Appendix D.** | |

## C. EMISSION POINT (STACK/VENT) INFORMATION
### (Optional for unregulated emissions units.)

**Emission Point Description and Type**

| | | |
|---|---|---|
| 1. Identification of Point on Plot Plan or Flow Diagram: **Storage Tanks** | | 2. Emission Point Type Code: **4** |
| 3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: | | |
| 4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: | | |
| 5. Discharge Type Code: **F** | 6. Stack Height: feet | 7. Exit Diameter: Feet |
| 8. Exit Temperature: °F | 9. Actual Volumetric Flow Rate: acfm | 10. Water Vapor: % |
| 11. Maximum Dry Standard Flow Rate: dscfm | | 12. Nonstack Emission Point Height: Feet **58** |
| 13. Emission Point UTM Coordinates... Zone: East (km): North (km): | | 14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS) |
| 15. Emission Point Comment: **See PSD report, Table 2-4 for detailed description of all tanks.** | | |

## D. SEGMENT (PROCESS/FUEL) INFORMATION

**Segment Description and Rate:** Segment 1 of 4

| | | |
|---|---|---|
| 1. Segment Description (Process/Fuel Type): **Organic Chemical Storage; Fixed Roof Tanks; Alcohols; Breathing Loss** | | |
| 2. Source Classification Code (SCC): **4-07-008-09** | 3. SCC Units: **1,000 Gallons Storage Capacity** | |
| 4. Maximum Hourly Rate: | 5. Maximum Annual Rate: | 6. Estimated Annual Activity Factor: **1,200.00** |
| 7. Maximum % Sulfur: | 8. Maximum % Ash: | 9. Million Btu per SCC Unit: |
| 10. Segment Comment: **One 1,000,000 gallon Fuel Ethanol Storage Tank, one 100,000 gallon 200 Proof Ethanol Storage Tank, and one 100,000 gallon Off-Spec Tank.** | | |

**Segment Description and Rate:** Segment 2 of 4

| | | |
|---|---|---|
| 1. Segment Description (Process/Fuel Type): **Organic Chemical Storage; Fixed Roof Tanks; Alcohols; Working Loss** | | |
| 2. Source Classification Code (SCC): **4-07-008-09** | 3. SCC Units: **1,000 Gallons Throughput** | |
| 4. Maximum Hourly Rate: | 5. Maximum Annual Rate: **36,000,000** | 6. Estimated Annual Activity Factor: |
| 7. Maximum % Sulfur: | 8. Maximum % Ash: | 9. Million Btu per SCC Unit: |
| 10. Segment Comment: **One 1,000,000 gallon Fuel Ethanol Storage Tank, one 100,000 gallon 200 Proof Ethanol Storage Tank, and one 100,000 gallon Off-Spec Tank.** | | |

## D. SEGMENT (PROCESS/FUEL) INFORMATION

**Segment Description and Rate:** Segment 3 of 4

| | | |
|---|---|---|
| 1. Segment Description (Process/Fuel Type):<br>**Bulk Terminals/Plans; Pet. Storage; Gasoline RVP 13: Standing Loss – Floating Roof Tank** | | |
| 2. Source Classification Code (SCC):<br>**4-04-002-07** | 3. SCC Units:<br>**1,000 Gallons Storage Capacity** | |
| 4. Maximum Hourly Rate: | 5. Maximum Annual Rate: | 6. Estimated Annual Activity Factor: **100** |
| 7. Maximum % Sulfur: | 8. Maximum % Ash: | 9. Million Btu per SCC Unit: |
| 10. Segment Comment:<br>**One 100,000 gallon Denaturant/Gasoline tank.** | | |

**Segment Description and Rate:** Segment 4 of 4

| | | |
|---|---|---|
| 1. Segment Description (Process/Fuel Type):<br>**Bulk Terminals/Plants; Pet. Storage; Gasoline RVP 13: Working Loss – Floating Roof Tank** | | |
| 2. Source Classification Code (SCC):<br>**4-04-002-10** | 3. SCC Units:<br>**1,000 Gallons Throughput** | |
| 4. Maximum Hourly Rate: | 5. Maximum Annual Rate:<br>**1,620** | 6. Estimated Annual Activity Factor: |
| 7. Maximum % Sulfur: | 8. Maximum % Ash: | 9. Million Btu per SCC Unit: |
| 10. Segment Comment:<br>**One 100,000 gallon Denaturant/Gasoline tank.** | | |

## E. EMISSIONS UNIT POLLUTANTS

**List of Pollutants Emitted by Emissions Unit**

| 1. Pollutant Emitted | 2. Primary Control Device Code | 3. Secondary Control Device Code | 4. Pollutant Regulatory Code |
|---|---|---|---|
| VOC | 091 | | WP |
| Total HAPs | 091 | | WP |
| | | | |
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## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **VOCs** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **0.98** lb/hour **3.93** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: <br>Reference: **USEPA TANKS 4.09d Program.** | 7. Emissions Method Code: **3** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **Refer to PSD Report, Appendix D, Table D-2.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted:<br>**HAPs** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions:<br>**0.024** lb/hour **0.094** tons/year | 4. Synthetically Limited?<br>☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable):<br>to tons/year | |
| 6. Emission Factor:<br><br>Reference: **USEPA TANKS 4.09d Program.** | 7. Emissions Method Code:<br>**3** |
| 8.a. Baseline Actual Emissions (if required):<br>tons/year | 8.b. Baseline 24-month Period:<br>From: To: |
| 9.a. Projected Actual Emissions (if required):<br>tons/year | 9.b. Projected Monitoring Period:<br>☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions:<br>**Refer to PSD Report, Appendix D, Table D-3.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## G. VISIBLE EMISSIONS INFORMATION

**Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.**

**Visible Emissions Limitation:** Visible Emissions Limitation _____of _____

| | |
|---|---|
| 1. Visible Emissions Subtype: | 2. Basis for Allowable Opacity:<br>☐ Rule ☐ Other |
| 3. Allowable Opacity:<br>Normal Conditions: % Exceptional Conditions: %<br>Maximum Period of Excess Opacity Allowed: min/hour | |
| 4. Method of Compliance: | |
| 5. Visible Emissions Comment: | |

## H. CONTINUOUS MONITOR INFORMATION

**Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.**

**Continuous Monitoring System:** Continuous Monitor _____ of _____

| | |
|---|---|
| 1. Parameter Code: | 2. Pollutant(s): |
| 3. CMS Requirement: | ☐ Rule ☐ Other |
| 4. Monitor Information...<br>Manufacturer:<br>Model Number: | Serial Number: |
| 5. Installation Date: | 6. Performance Specification Test Date: |
| 7. Continuous Monitor Comment: | |

**Continuous Monitoring System:** Continuous Monitor _____ of _____

| | |
|---|---|
| 1. Parameter Code: | 2. Pollutant(s): |
| 3. CMS Requirement: | ☐ Rule ☐ Other |
| 4. Monitor Information...<br>Manufacturer:<br>Model Number: | Serial Number: |
| 5. Installation Date: | 6. Performance Specification Test Date: |
| 7. Continuous Monitor Comment: | |

## I. EMISSIONS UNIT ADDITIONAL INFORMATION

**Additional Requirements for All Applications, Except as Otherwise Stated**

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **PSD Report** ☐ Previously Submitted, Date ___________

2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: __________ ☐ Previously Submitted, Date ___________

3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **PSD Report** ☐ Previously Submitted, Date ___________

4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: __________ ☐ Previously Submitted, Date ___________
   ☒ Not Applicable (construction application)

5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: __________ ☐ Previously Submitted, Date ___________
   ☒ Not Applicable

6. Compliance Demonstration Reports/Records:
   ☐ Attached, Document ID: __________
   Test Date(s)/Pollutant(s) Tested: ______________________________

   ☐ Previously Submitted, Date: _______
   Test Date(s)/Pollutant(s) Tested: ______________________________

   ☐ To be Submitted, Date (if known): __________
   Test Date(s)/Pollutant(s) Tested: ______________________________

   ☒ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute:
   ☐ Attached, Document ID: __________ ☒ Not Applicable

## I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

**Additional Requirements for Air Construction Permit Applications**

| | |
|---|---|
| 1. | Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)):<br>☒ Attached, Document ID: **PSD Report** ☐ Not Applicable |
| 2. | Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.):<br>☐ Attached, Document ID: ______ ☒ Not Applicable |
| 3. | Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only)<br>☐ Attached, Document ID: ______ ☒ Not Applicable |

**Additional Requirements for Title V Air Operation Permit Applications**

| | |
|---|---|
| 1. | Identification of Applicable Requirements:<br>☐ Attached, Document ID: ______ |
| 2. | Compliance Assurance Monitoring:<br>☐ Attached, Document ID: ______ ☐ Not Applicable |
| 3. | Alternative Methods of Operation:<br>☐ Attached, Document ID: ______ ☐ Not Applicable |
| 4. | Alternative Modes of Operation (Emissions Trading):<br>☐ Attached, Document ID: ______ ☐ Not Applicable |

**Additional Requirements Comment**

| |
|---|
| |

## III. EMISSIONS UNIT INFORMATION

**Title V Air Operation Permit Application -** For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for an initial, revised or renewal Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

**Air Construction Permit or FESOP Application -** For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for an air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

**Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application –** Where this application is used to apply for both an air construction permit and a revised or renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes, and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this application that is subject to air construction permitting and for each such emissions unit that is a regulated or unregulated unit for purposes of Title V permitting. (An emissions unit may be exempt from air construction permitting but still be classified as an unregulated unit for Title V purposes.) Emissions units classified as insignificant for Title V purposes are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

## A. GENERAL EMISSIONS UNIT INFORMATION

**Title V Air Operation Permit Emissions Unit Classification**

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

**Emissions Unit Description and Status**

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
   **Emergency Generator**

3. Emissions Unit Identification Number:

| 4. Emissions Unit Status Code: | 5. Commence Construction Date: | 6. Initial Startup Date: | 7. Emissions Unit Major Group SIC Code: |
|---|---|---|---|
| **C** | | | **28** |

8. Federal Program Applicability: (Check all that apply)

   ☐ Acid Rain Unit

   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: **CAT** Model Number: **SR4B HV**

10. Generator Nameplate Rating: **2** MW

11. Emissions Unit Comment:
    **One emergency generator will be used in the event of power supply disruptions and for black start. The generators will be fired by ultra low sulfur diesel fuel or natural gas.**

**Emissions Unit Control Equipment/Method:** Control ____ of ____

| | |
|---|---|
| 1. Control Equipment/Method Description: | |
| 2. Control Device or Method Code: | |

**Emissions Unit Control Equipment/Method:** Control ____ of ____

| | |
|---|---|
| 1. Control Equipment/Method Description: | |
| 2. Control Device or Method Code: | |

**Emissions Unit Control Equipment/Method:** Control ____ of ____

| | |
|---|---|
| 1. Control Equipment/Method Description: | |
| 2. Control Device or Method Code: | |

**Emissions Unit Control Equipment/Method:** Control ____ of ____

| | |
|---|---|
| 1. Control Equipment/Method Description: | |
| 2. Control Device or Method Code: | |

## B. EMISSIONS UNIT CAPACITY INFORMATION
### (Optional for unregulated emissions units.)

**Emissions Unit Operating Capacity and Schedule**

| | | | |
|---|---|---|---|
| 1. Maximum Process or Throughput Rate: | | | |
| 2. Maximum Production Rate: | | | |
| 3. Maximum Heat Input Rate: **19.45** million Btu/hr | | | |
| 4. Maximum Incineration Rate: | pounds/hr<br>tons/day | | |
| 5. Requested Maximum Operating Schedule: | hours/day<br>weeks/year | | days/week<br>**500** hours/year |
| 6. Operating Capacity/Schedule Comment:<br><br>**See PSD Table 2-20. The generator can operate up to 500 hr/yr.** | | | |

## C. EMISSION POINT (STACK/VENT) INFORMATION
### (Optional for unregulated emissions units.)

**Emission Point Description and Type**

| | | |
|---|---|---|
| 1. Identification of Point on Plot Plan or Flow Diagram: **Emergency Generator** | | 2. Emission Point Type Code: **3** |
| 3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **This unit consists of one emergency generator.** | | |
| 4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: | | |
| 5. Discharge Type Code: **V** | 6. Stack Height: **5** feet | 7. Exit Diameter: **1** Feet |
| 8. Exit Temperature: **500**°F | 9. Actual Volumetric Flow Rate: acfm | 10. Water Vapor: % |
| 11. Maximum Dry Standard Flow Rate: Dscfm | | 12. Nonstack Emission Point Height: Feet |
| 13. Emission Point UTM Coordinates... Zone: East (km): North (km): | | 14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS) |
| 15. Emission Point Comment: **See PSD report Table 2-20 and Appendix F for detailed description.** | | |

## D. SEGMENT (PROCESS/FUEL) INFORMATION

**Segment Description and Rate:** Segment 1 of 2

| | | |
|---|---|---|
| 1. Segment Description (Process/Fuel Type):<br>**Internal Combustion Engines - Industrial; Distillate Oil (Diesel); Reciprocating** | | |
| 2. Source Classification Code (SCC):<br>**2-02-001-02** | 3. SCC Units:<br>**1,000 Gallons Burned** | |
| 4. Maximum Hourly Rate:<br>**0.139** | 5. Maximum Annual Rate:<br>**69.5** | 6. Estimated Annual Activity Factor: |
| 7. Maximum % Sulfur:<br>**0.0015** | 8. Maximum % Ash: | 9. Million Btu per SCC Unit:<br>**140** |
| 10. Segment Comment:<br>**Based on 138.9 gal/hr of No. 2 Fuel Oil. Annual rate is based on 500 hr/yr.**<br>**See PSD report Table 2-20.** | | |

**Segment Description and Rate:** Segment 2 of 2

| | | |
|---|---|---|
| 1. Segment Description (Process/Fuel Type):<br>**Internal Combustion Engines - Industrial; Natural Gas: Reciprocating** | | |
| 2. Source Classification Code (SCC):<br>**2-02-002-02** | 3. SCC Units:<br>**Million Cubic Feet Burned** | |
| 4. Maximum Hourly Rate:<br>**0.019** | 5. Maximum Annual Rate:<br>**9.53** | 6. Estimated Annual Activity Factor: |
| 7. Maximum % Sulfur: | 8. Maximum % Ash: | 9. Million Btu per SCC Unit:<br>**1,020** |
| 10. Segment Comment:<br>**Maximum hourly rate is based on 19.45 MMBtu/hr / 1,020 MMBtu/MMscf = 0.019 MMscf/hr.**<br>**Annual rate is based on 0.019 MMscf/hr x 500 hr/yr = 9.53 MMscf/yr.**<br>**See PSD report Table 2-20.** | | |

EMISSIONS UNIT INFORMATION
Section [6]
**Emergency Generator**

## E. EMISSIONS UNIT POLLUTANTS

**List of Pollutants Emitted by Emissions Unit**

| 1. Pollutant Emitted | 2. Primary Control Device Code | 3. Secondary Control Device Code | 4. Pollutant Regulatory Code |
|---|---|---|---|
| **SO2** | | | **NS** |
| **NOx** | | | **EL** |
| **CO** | | | **EL** |
| **PM** | | | **EL** |
| **PM10** | | | **NS** |
| **PM2.5** | | | **NS** |
| **VOC** | | | **EL** |
| **Total HAPs** | | | **WP** |
| | | | |
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## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **SO2** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **0.011** lb/hour **0.0029** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **0.00059 lb/MMBtu**<br>Reference: **Refer to PSD Table 2-20.** | 7. Emissions Method Code: **3** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions:<br>**Emission factor based on AP-42, Section 1.5, 1.5 gr $SO_2$/100 $ft^3$ of propane. Refer to PSD Table 2-20.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **NOx** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **31.80** lb/hour **7.95** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **5.39 g/hp-hr**<br>Reference: **Refer to PSD Table 2-20.** | 7. Emissions Method Code: **3** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **Refer to PSD Table 2-20.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions 1 of 1

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: **RULE** | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: **NMHC + NOx = 6.4 g/kW-hr** | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: **Manufacturer's certification** | |
| 6. Allowable Emissions Comment (Description of Operating Method): **40 CFR 60, Subpart IIII, 60.4202(a)(2).** | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>**

| | |
|---|---|
| 1. Pollutant Emitted: **CO** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **1.71** lb/hour **0.43** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **0.29 g/hp-hr**<br>Reference: **Refer to PSD Table 2-20.** | 7. Emissions Method Code: **3** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **Refer to PSD Table 2-20.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions 1 of 1

| | |
|---|---|
| 1. Basis for Allowable Emissions Code:<br>**RULE** | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units:<br>**3.5 g/kW-hr** | 4. Equivalent Allowable Emissions:<br>lb/hour tons/year |
| 5. Method of Compliance:<br>**Manufacturer's certification** | |
| 6. Allowable Emissions Comment (Description of Operating Method):<br>**40 CFR 60, Subpart IIII, 60.4202(a)(2).** | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions:<br>lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions:<br>lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **PM** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **0.15** lb/hour **0.038** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **0.026 g/hp-hr**<br>Reference: **Refer to PSD Table 2-20.** | 7. Emissions Method Code: **3** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **Refer to PSD Table 2-20.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions 1 of 1

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: **RULE** | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: **0.20 g/kW-hr** | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: **Manufacturer's certification** | |
| 6. Allowable Emissions Comment (Description of Operating Method): **40 CFR 60, Subpart IIII, 60.4202(a)(2).** | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **PM10** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **0.15** lb/hour **0.038** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **0.026 g/hp-hr**<br>Reference: **Refer to PSD Table 2-20.** | 7. Emissions Method Code: **3** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **Refer to PSD Table 2-20.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **PM2.5** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **0.15** lb/hour **0.038** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **0.026 g/hp-hr**<br>Reference: **Refer to PSD Table 2-20.** | 7. Emissions Method Code: **3** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **Refer to PSD Table 2-20.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **VOC** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **0.65** lb/hour **0.16** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **0.11 g/hp-hr**<br>Reference: **Refer to PSD Table 2-20.** | 7. Emissions Method Code: **3** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **Refer to PSD Table 2-20.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions 1 of 1

| | |
|---|---|
| 1. Basis for Allowable Emissions Code:<br>**RULE** | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units:<br>**NMHC + NOx = 6.4 g/kW-hr** | 4. Equivalent Allowable Emissions:<br>lb/hour tons/year |
| 5. Method of Compliance:<br>**Manufacturer's certification** | |
| 6. Allowable Emissions Comment (Description of Operating Method):<br>**40 CFR 60, Subpart IIII, 60.4202(a)(2).** | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions:<br>lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions:<br>lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **HAPs** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **0.083** lb/hour **0.021** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **AP-42**<br>Reference: | 7. Emissions Method Code: **3** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **Refer to PSD Table 2-21.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions _____of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## G. VISIBLE EMISSIONS INFORMATION

**Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.**

**Visible Emissions Limitation:** Visible Emissions Limitation _____of _____

| | |
|---|---|
| 1. Visible Emissions Subtype: | 2. Basis for Allowable Opacity:<br>☐ Rule ☐ Other |
| 3. Allowable Opacity:<br>Normal Conditions: % Exceptional Conditions: %<br>Maximum Period of Excess Opacity Allowed: min/hour | |
| 4. Method of Compliance: | |
| 5. Visible Emissions Comment: | |

## H. CONTINUOUS MONITOR INFORMATION

**Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.**

**Continuous Monitoring System:** Continuous Monitor ____ of ____

| | |
|---|---|
| 1. Parameter Code: | 2. Pollutant(s): |
| 3. CMS Requirement: | ☐ Rule ☐ Other |
| 4. Monitor Information... Manufacturer: Model Number: | Serial Number: |
| 5. Installation Date: | 6. Performance Specification Test Date: |
| 7. Continuous Monitor Comment: | |

**Continuous Monitoring System:** Continuous Monitor ____ of ____

| | |
|---|---|
| 1. Parameter Code: | 2. Pollutant(s): |
| 3. CMS Requirement: | ☐ Rule ☐ Other |
| 4. Monitor Information... Manufacturer: Model Number: | Serial Number: |
| 5. Installation Date: | 6. Performance Specification Test Date: |
| 7. Continuous Monitor Comment: | |

# I. EMISSIONS UNIT ADDITIONAL INFORMATION

## Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☒ Attached, Document ID: **PSD Report** ☐ Previously Submitted, Date ___________

2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☒ Attached, Document ID: **PSD Report** ☐ Previously Submitted, Date ___________

3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☒ Attached, Document ID: **PSD Report** ☐ Previously Submitted, Date ___________

4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: __________ ☐ Previously Submitted, Date ___________
☒ Not Applicable (construction application)

5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: __________ ☐ Previously Submitted, Date ___________
☒ Not Applicable

6. Compliance Demonstration Reports/Records:
☐ Attached, Document ID: __________
Test Date(s)/Pollutant(s) Tested: ___________________________________
☐ Previously Submitted, Date: _______
Test Date(s)/Pollutant(s) Tested: ___________________________________
☐ To be Submitted, Date (if known): __________
Test Date(s)/Pollutant(s) Tested: ___________________________________
☒ Not Applicable
Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute:
☐ Attached, Document ID: __________ ☒ Not Applicable

## I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

**Additional Requirements for Air Construction Permit Applications**

| | |
|---|---|
| 1. | Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)):<br>☐ Attached, Document ID: _ ☒ Not Applicable |
| 2. | Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.):<br>☐ Attached, Document ID: ____________ ☒ Not Applicable |
| 3. | Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only)<br>☐ Attached, Document ID: ____________ ☒ Not Applicable |

**Additional Requirements for Title V Air Operation Permit Applications**

| | |
|---|---|
| 1. | Identification of Applicable Requirements:<br>☐ Attached, Document ID: ____________ |
| 2. | Compliance Assurance Monitoring:<br>☐ Attached, Document ID: ____________ ☐ Not Applicable |
| 3. | Alternative Methods of Operation:<br>☐ Attached, Document ID: ____________ ☐ Not Applicable |
| 4. | Alternative Modes of Operation (Emissions Trading):<br>☐ Attached, Document ID: ____________ ☐ Not Applicable |

**Additional Requirements Comment**

| |
|---|
| |

# III. EMISSIONS UNIT INFORMATION

**Title V Air Operation Permit Application** - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for an initial, revised or renewal Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

**Air Construction Permit or FESOP Application** - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for an air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

**Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application** – Where this application is used to apply for both an air construction permit and a revised or renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes, and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this application that is subject to air construction permitting and for each such emissions unit that is a regulated or unregulated unit for purposes of Title V permitting. (An emissions unit may be exempt from air construction permitting but still be classified as an unregulated unit for Title V purposes.) Emissions units classified as insignificant for Title V purposes are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

## A. GENERAL EMISSIONS UNIT INFORMATION

**Title V Air Operation Permit Emissions Unit Classification**

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

**Emissions Unit Description and Status**

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
   **Emergency Fire Pump**

3. Emissions Unit Identification Number:

| 4. Emissions Unit Status Code: **C** | 5. Commence Construction Date: | 6. Initial Startup Date: | 7. Emissions Unit Major Group SIC Code: **28** |
|---|---|---|---|

8. Federal Program Applicability: (Check all that apply)

   ☐ Acid Rain Unit

   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: **CAT** Model Number: **C18 ACERT**

10. Generator Nameplate Rating: **0.45** MW

11. Emissions Unit Comment:
    **The Emergency Fire Pump will be used to pump water in the event of a fire. The fire pump engine will be fired by ultra sulfur diesel fuel or natural gas.**

**Emissions Unit Control Equipment/Method:** Control ____ of ____

| |
|---|
| 1. Control Equipment/Method Description: |
| 2. Control Device or Method Code: |

**Emissions Unit Control Equipment/Method:** Control ____ of ____

| |
|---|
| 1. Control Equipment/Method Description: |
| 2. Control Device or Method Code: |

**Emissions Unit Control Equipment/Method:** Control ____ of ____

| |
|---|
| 1. Control Equipment/Method Description: |
| 2. Control Device or Method Code: |

**Emissions Unit Control Equipment/Method:** Control ____ of ____

| |
|---|
| 1. Control Equipment/Method Description: |
| 2. Control Device or Method Code: |

## B. EMISSIONS UNIT CAPACITY INFORMATION
## (Optional for unregulated emissions units.)

**Emissions Unit Operating Capacity and Schedule**

| | | |
|---|---|---|
| 1. Maximum Process or Throughput Rate: | | |
| 2. Maximum Production Rate: | | |
| 3. Maximum Heat Input Rate: **4.3** million Btu/hr | | |
| 4. Maximum Incineration Rate: | pounds/hr<br>tons/day | |
| 5. Requested Maximum Operating Schedule: | hours/day<br>weeks/year | days/week<br>**500** hours/year |
| 6. Operating Capacity/Schedule Comment:<br><br>**See PSD Table 2-22.** | | |

## C. EMISSION POINT (STACK/VENT) INFORMATION
### (Optional for unregulated emissions units.)

**Emission Point Description and Type**

| | |
|---|---|
| 1. Identification of Point on Plot Plan or Flow Diagram: **Emergency Fire Pump** | 2. Emission Point Type Code: **1** |
| 3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: | |
| 4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: | |

| | | |
|---|---|---|
| 5. Discharge Type Code: **V** | 6. Stack Height: **5** feet | 7. Exit Diameter: **1** Feet |
| 8. Exit Temperature: **600**°F | 9. Actual Volumetric Flow Rate: acfm | 10. Water Vapor: % |

| | |
|---|---|
| 11. Maximum Dry Standard Flow Rate: dscfm | 12. Nonstack Emission Point Height: Feet |
| 13. Emission Point UTM Coordinates... Zone: East (km): North (km): | 14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS) |
| 15. Emission Point Comment: **See PSD report Table 2-22 and Appendix F for detailed description.** | |

## D. SEGMENT (PROCESS/FUEL) INFORMATION

**Segment Description and Rate:** Segment 1 of 2

| | | |
|---|---|---|
| 1. Segment Description (Process/Fuel Type): **Internal Combustion Engines - Industrial; Distillate Oil (Diesel); Reciprocating** | | |
| 2. Source Classification Code (SCC): **2-02-001-02** | 3. SCC Units: **1,000 Gallons Burned** | |
| 4. Maximum Hourly Rate: **0.031** | 5. Maximum Annual Rate: **15.4** | 6. Estimated Annual Activity Factor: |
| 7. Maximum % Sulfur: | 8. Maximum % Ash: | 9. Million Btu per SCC Unit: **140** |
| 10. Segment Comment: **Based on 4.3 MMBtu/hr and 140,000 Btu/gal of No. 2 Fuel Oil. Annual rate is based on 500 hr/yr. See PSD report Table 2-22.** | | |

**Segment Description and Rate:** Segment 2 of 2

| | | |
|---|---|---|
| 1. Segment Description (Process/Fuel Type): **Internal Combustion Engines - Industrial; Natural Gas: Reciprocating** | | |
| 2. Source Classification Code (SCC): **2-02-002-02** | 3. SCC Units: **Million standard cubic feet** | |
| 4. Maximum Hourly Rate: **0.0042** | 5. Maximum Annual Rate: **2.1** | 6. Estimated Annual Activity Factor: |
| 7. Maximum % Sulfur: | 8. Maximum % Ash: | 9. Million Btu per SCC Unit: **1,020** |
| 10. Segment Comment: **Maximum hourly rate is based on 4.3 MMBtu/hr / 1,020 MMBtu/MMscf = 0.0042 MMscf/hr. Annual rate is based on 0.0042 MMscf/hr x 500 hr/yr = 2.1 MMscf/yr. See PSD report Table 2-22.** | | |

EMISSIONS UNIT INFORMATION
Section [7]
**Emergency Fire Pump**

## E. EMISSIONS UNIT POLLUTANTS

**List of Pollutants Emitted by Emissions Unit**

| 1. Pollutant Emitted | 2. Primary Control Device Code | 3. Secondary Control Device Code | 4. Pollutant Regulatory Code |
|---|---|---|---|
| **SO2** | | | **NS** |
| **NOx** | | | **EL** |
| **CO** | | | **EL** |
| **PM** | | | **EL** |
| **PM10** | | | **NS** |
| **PM2.5** | | | **NS** |
| **VOC** | | | **EL** |
| **Total HAPs** | | | **WP** |
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## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **SO2** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **0.0025** lb/hour **0.00063** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **0.00059 lb/MMBtu**<br>Reference: **Refer to PSD Table 2-22.** | 7. Emissions Method Code: **3** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **Emission factor based on AP-42, Section 1.4. Refer to PSD Table 2-22.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| **1. Basis for Allowable Emissions Code:** | **2. Future Effective Date of Allowable Emissions:** |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **NOx** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **3.55** lb/hour **0.89** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **3.6 g/kW-hr**<br>Reference: **Refer to PSD Table 2-22.** | 7. Emissions Method Code: **0** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **Refer to PSD Table 2-22.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions 1 of 1

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: **RULE** | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: **3.6 g/kW-hr** | 4. Equivalent Allowable Emissions: **3.55** lb/hour **0.89** tons/year |
| 5. Method of Compliance: **Manufacturer's certification** | |
| 6. Allowable Emissions Comment (Description of Operating Method): **40 CFR 60, Subpart IIII, 60.4205(c)** | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **CO** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **3.45** lb/hour **0.86** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **3.50 g/kW-hr**<br>Reference: **Refer to PSD Table 2-22.** | 7. Emissions Method Code: **0** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **Refer to PSD Table 2-22.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions 1 of 1

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: **RULE** | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: **3.50 g/kW-hr** | 4. Equivalent Allowable Emissions: **3.45** lb/hour **0.86** tons/year |
| 5. Method of Compliance: **Manufacturer's certification** | |
| 6. Allowable Emissions Comment (Description of Operating Method): **40 CFR 60, Subpart IIII, 60.4205(c)** | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>**

| | |
|---|---|
| 1. Pollutant Emitted: **PM** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **0.20** lb/hour **0.049** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **0.20 g/kW-hr**<br>Reference: **Refer to PSD Table 2-22.** | 7. Emissions Method Code: **0** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions:<br>**Refer to PSD Table 2-22.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions 1 of 1

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: **RULE** | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: **0.20 g/kW-hr** | 4. Equivalent Allowable Emissions: **0.20** lb/hour **0.049** tons/year |
| 5. Method of Compliance: **Manufacturer's certification** | |
| 6. Allowable Emissions Comment (Description of Operating Method): **40 CFR 60, Subpart IIII, 60.4205(c)** | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **PM10** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **0.20** lb/hour **0.049** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **0.20 g/kW-hr**<br>Reference: **Refer to PSD Table 2-22.** | 7. Emissions Method Code: **3** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions:<br>**Refer to PSD Table 2-22.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **PM2.5** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **0.20** lb/hour **0.049** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **0.20 g/kW-hr**<br>Reference: **Refer to PSD Table 2-22.** | 7. Emissions Method Code: **3** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions:<br>**Refer to PSD Table 2-22.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>**

| | |
|---|---|
| 1. Pollutant Emitted: **VOC** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **0.39** lb/hour **0.10** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **0.40 g/kW-hr**<br>Reference: **Refer to PSD Table 2-22.** | 7. Emissions Method Code: **0** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **Refer to PSD Table 2-22.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions 1 of 1

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: **RULE** | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: **0.40 g/kW-hr** | 4. Equivalent Allowable Emissions: **0.39** lb/hour **0.10** tons/year |
| 5. Method of Compliance: **Manufacturer's certification** | |
| 6. Allowable Emissions Comment (Description of Operating Method): **40 CFR 60, Subpart IIII, 60.4205(c)** | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **HAPs** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **0.027** lb/hour **0.0068** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **AP-42**<br>Reference: | 7. Emissions Method Code: **3** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **Refer to PSD Table 2-23.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## G. VISIBLE EMISSIONS INFORMATION

**Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.**

**Visible Emissions Limitation:** Visible Emissions Limitation _____of _____

| | |
|---|---|
| 1. Visible Emissions Subtype: | 2. Basis for Allowable Opacity:<br>☐ Rule ☐ Other |
| 3. Allowable Opacity:<br>Normal Conditions: % Exceptional Conditions: %<br>Maximum Period of Excess Opacity Allowed: min/hour | |
| 4. Method of Compliance: | |
| 5. Visible Emissions Comment: | |

## H. CONTINUOUS MONITOR INFORMATION

**Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.**

**Continuous Monitoring System:** Continuous Monitor ____ of ____

| | |
|---|---|
| 1. Parameter Code: | 2. Pollutant(s): |
| 3. CMS Requirement: | ☐ Rule ☐ Other |
| 4. Monitor Information...<br>Manufacturer:<br>Model Number: | Serial Number: |
| 5. Installation Date: | 6. Performance Specification Test Date: |
| 7. Continuous Monitor Comment: | |

**Continuous Monitoring System:** Continuous Monitor ____ of ____

| | |
|---|---|
| 1. Parameter Code: | 2. Pollutant(s): |
| 3. CMS Requirement: | ☐ Rule ☐ Other |
| 4. Monitor Information...<br>Manufacturer:<br>Model Number: | Serial Number: |
| 5. Installation Date: | 6. Performance Specification Test Date: |
| 7. Continuous Monitor Comment: | |

## I. EMISSIONS UNIT ADDITIONAL INFORMATION

**Additional Requirements for All Applications, Except as Otherwise Stated**

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☒ Attached, Document ID: **PSD Report** ☐ Previously Submitted, Date ___________

2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☒ Attached, Document ID: **PSD Report** ☐ Previously Submitted, Date ___________

3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☒ Attached, Document ID: **PSD Report** ☐ Previously Submitted, Date ___________

4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: __________ ☐ Previously Submitted, Date ___________
☒ Not Applicable (construction application)

5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: __________ ☐ Previously Submitted, Date ___________
☒ Not Applicable

6. Compliance Demonstration Reports/Records:
☐ Attached, Document ID: __________
Test Date(s)/Pollutant(s) Tested: ______________________________
☐ Previously Submitted, Date: _______
Test Date(s)/Pollutant(s) Tested: ______________________________
☐ To be Submitted, Date (if known): __________
Test Date(s)/Pollutant(s) Tested: ______________________________
☒ Not Applicable
Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute:
☐ Attached, Document ID: __________ ☒ Not Applicable

## I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

**Additional Requirements for Air Construction Permit Applications**

| | |
|---|---|
| 1. | Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)):<br>☐ Attached, Document ID: _ ☒ Not Applicable |
| 2. | Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.):<br>☐ Attached, Document ID: __________ ☒ Not Applicable |
| 3. | Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only)<br>☐ Attached, Document ID: __________ ☒ Not Applicable |

**Additional Requirements for Title V Air Operation Permit Applications**

| | |
|---|---|
| 1. | Identification of Applicable Requirements:<br>☐ Attached, Document ID: __________ |
| 2. | Compliance Assurance Monitoring:<br>☐ Attached, Document ID: __________ ☐ Not Applicable |
| 3. | Alternative Methods of Operation:<br>☐ Attached, Document ID: __________ ☐ Not Applicable |
| 4. | Alternative Modes of Operation (Emissions Trading):<br>☐ Attached, Document ID: __________ ☐ Not Applicable |

**Additional Requirements Comment**

| |
|---|
| |

# III. EMISSIONS UNIT INFORMATION

**Title V Air Operation Permit Application** - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for an initial, revised or renewal Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

**Air Construction Permit or FESOP Application** - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for an air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

**Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application** – Where this application is used to apply for both an air construction permit and a revised or renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes, and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this application that is subject to air construction permitting and for each such emissions unit that is a regulated or unregulated unit for purposes of Title V permitting. (An emissions unit may be exempt from air construction permitting but still be classified as an unregulated unit for Title V purposes.) Emissions units classified as insignificant for Title V purposes are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

## A. GENERAL EMISSIONS UNIT INFORMATION

**Title V Air Operation Permit Emissions Unit Classification**

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

**Emissions Unit Description and Status**

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
   **Miscellaneous Unregulated Emission Units**

3. Emissions Unit Identification Number:

| | | | |
|---|---|---|---|
| 4. Emissions Unit Status Code: **C** | 5. Commence Construction Date: | 6. Initial Startup Date: | 7. Emissions Unit Major Group SIC Code: **28** |

8. Federal Program Applicability: (Check all that apply)

   ☐ Acid Rain Unit

   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:
    **Includes the Corrosion Inhibitor Tank, Cooling Tower, Ash Silo, and Lime/Limestone Silos.**

**Emissions Unit Control Equipment/Method:** Control 1 of 1

| | |
|---|---|
| 1. Control Equipment/Method Description: **Fabric Filter – Low Temperature (T<180F): Ash Silo (1) and Lime/Limestone Silos (2)** | |
| 2. Control Device or Method Code: **018** | |

**Emissions Unit Control Equipment/Method:** Control ____ of ____

| | |
|---|---|
| 1. Control Equipment/Method Description: | |
| 2. Control Device or Method Code: | |

**Emissions Unit Control Equipment/Method:** Control ____ of ____

| | |
|---|---|
| 1. Control Equipment/Method Description: | |
| 2. Control Device or Method Code: | |

**Emissions Unit Control Equipment/Method:** Control ____ of ____

| | |
|---|---|
| 1. Control Equipment/Method Description: | |
| 2. Control Device or Method Code: | |

## B. EMISSIONS UNIT CAPACITY INFORMATION
### (Optional for unregulated emissions units.)

**Emissions Unit Operating Capacity and Schedule**

| | |
|---|---|
| 1. | Maximum Process or Throughput Rate: **37,620,000 gal/yr – Ethanol & Denaturant/Gasoline** |
| 2. | Maximum Production Rate: **120,000 gal/day - Ethanol** |
| 3. | Maximum Heat Input Rate: million Btu/hr |
| 4. | Maximum Incineration Rate: pounds/hr<br>tons/day |
| 5. | Requested Maximum Operating Schedule:<br>**24** hours/day **7** days/week<br>**52** weeks/year **8,760** hours/year |
| 6. | Operating Capacity/Schedule Comment:<br><br>**Maximum daily ethanol production rate is 120,000 gal/day.**<br>**Maximum annual ethanol production rate is 36,000,000 gal/yr. Maximum denaturant/gasoline throughput is 1,620,000 gal/yr.**<br>**See PSD Report, Table 2-3 and Appendix D.**<br>**Maximum throughput rate of lime/limestone is 1,380 TPY.** |

## C. EMISSION POINT (STACK/VENT) INFORMATION
### (Optional for unregulated emissions units.)

**Emission Point Description and Type**

| | |
|---|---|
| 1. Identification of Point on Plot Plan or Flow Diagram: | 2. Emission Point Type Code: **3** |
| 3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **Ash Silo (1) and Lime/Limestone silos (2)** | |
| 4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: | |

| | | |
|---|---|---|
| 5. Discharge Type Code: **F** | 6. Stack Height: feet | 7. Exit Diameter: Feet |
| 8. Exit Temperature: °F | 9. Actual Volumetric Flow Rate: acfm | 10. Water Vapor: % |

| | |
|---|---|
| 11. Maximum Dry Standard Flow Rate: dscfm | 12. Nonstack Emission Point Height: Feet **8** |
| 13. Emission Point UTM Coordinates... Zone: East (km): North (km): | 14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS) |
| 15. Emission Point Comment: **Emission Point Height based on the Corrosion Inhibitor Tank; see PSD report, Table 2-3 for detailed description of all tanks. See PSD report Table 2-17 for Cooling Tower details and Table 2-24 for Ahs Silo and Lime/Limestone Silo details.** | |

## D. SEGMENT (PROCESS/FUEL) INFORMATION

**Segment Description and Rate:** Segment 1 of 2

| | | |
|---|---|---|
| 1. Segment Description (Process/Fuel Type):<br>**Organic Chemical Storage; Fixed Roof Tanks; Alcohols; Breathing Loss** | | |
| 2. Source Classification Code (SCC):<br>**4-07-008-09** | 3. SCC Units:<br>**1,000 Gallons Storage Capacity** | |
| 4. Maximum Hourly Rate: | 5. Maximum Annual Rate: | 6. Estimated Annual Activity Factor: **2.0** |
| 7. Maximum % Sulfur: | 8. Maximum % Ash: | 9. Million Btu per SCC Unit: |
| 10. Segment Comment:<br>**One 2,300 gallon Corrosion Inhibitor Tank.** | | |

**Segment Description and Rate:** Segment 2 of 2

| | | |
|---|---|---|
| 1. Segment Description (Process/Fuel Type):<br>**Organic Chemical Storage; Fixed Roof Tanks; Alcohols; Working Loss** | | |
| 2. Source Classification Code (SCC):<br>**4-07-008-10** | 3. SCC Units:<br>**1,000 Gallons Throughput** | |
| 4. Maximum Hourly Rate: | 5. Maximum Annual Rate:<br>**2.7** | 6. Estimated Annual Activity Factor: |
| 7. Maximum % Sulfur: | 8. Maximum % Ash: | 9. Million Btu per SCC Unit: |
| 10. Segment Comment:<br>**One 2,300 gallon Corrosion Inhibitor Tank.** | | |

## E. EMISSIONS UNIT POLLUTANTS

**List of Pollutants Emitted by Emissions Unit**

| 1. Pollutant Emitted | 2. Primary Control Device Code | 3. Secondary Control Device Code | 4. Pollutant Regulatory Code |
|---|---|---|---|
| **VOC** | | | **WP** |
| **PM** | **018** | | **WP** |
| **PM10** | **018** | | **WP** |
| **PM2.5** | **018** | | **WP** |
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## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **VOCs** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **0.0018** lb/hour **0.0060** tons/year | 4. Synthetically Limited? ☐ Yes ☒ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **AP-42**<br>Reference: **USEPA TANKS 4.09d Program.** | 7. Emissions Method Code: **3** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **Refer to PSD Report, Appendix D, Table D-1.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **PM** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **0.72** lb/hour **1.22** tons/year | 4. Synthetically Limited? ☐ Yes ☒ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: <br>Reference: **PSD Report.** | 7. Emissions Method Code: **3** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: <br>**Refer to PSD Report, Tables 2-17 for the cooling tower, and Table 2-24 for the silos.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **PM10** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **0.67** lb/hour **1.04** tons/year | 4. Synthetically Limited? ☐ Yes ☒ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor:<br>Reference: **PSD Report.** | 7. Emissions Method Code: **3** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions:<br>**Refer to PSD Report, Tables 2-17 for the cooling tower, and Table 2-24 for the silos.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions ____ of ____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **PM2.5** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **0.67** lb/hour **1.04** tons/year | 4. Synthetically Limited? ☐ Yes ☒ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: <br>Reference: **PSD Report.** | 7. Emissions Method Code: **3** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **Refer to PSD Report, Tables 2-17 for the cooling tower, and Table 2-24 for the silos.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## G. VISIBLE EMISSIONS INFORMATION

**Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.**

**Visible Emissions Limitation:** Visible Emissions Limitation _____of _____

| | |
|---|---|
| 1. Visible Emissions Subtype: | 2. Basis for Allowable Opacity:<br>☐ Rule ☐ Other |
| 3. Allowable Opacity:<br>Normal Conditions: % Exceptional Conditions: %<br>Maximum Period of Excess Opacity Allowed: min/hour | |
| 4. Method of Compliance: | |
| 5. Visible Emissions Comment: | |

## H. CONTINUOUS MONITOR INFORMATION

**Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.**

**Continuous Monitoring System:** Continuous Monitor ____ of ____

| | |
|---|---|
| 1. Parameter Code: | 2. Pollutant(s): |
| 3. CMS Requirement: | ☐ Rule ☐ Other |
| 4. Monitor Information...<br>Manufacturer:<br>Model Number: | Serial Number: |
| 5. Installation Date: | 6. Performance Specification Test Date: |
| 7. Continuous Monitor Comment: | |

**Continuous Monitoring System:** Continuous Monitor ____ of ____

| | |
|---|---|
| 1. Parameter Code: | 2. Pollutant(s): |
| 3. CMS Requirement: | ☐ Rule ☐ Other |
| 4. Monitor Information...<br>Manufacturer:<br>Model Number: | Serial Number: |
| 5. Installation Date: | 6. Performance Specification Test Date: |
| 7. Continuous Monitor Comment: | |

# I. EMISSIONS UNIT ADDITIONAL INFORMATION

## Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **PSD Report** ☐ Previously Submitted, Date ___________
2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: __________ ☐ Previously Submitted, Date ___________
3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **PSD Report** ☐ Previously Submitted, Date ___________
4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: __________ ☐ Previously Submitted, Date ___________
   ☒ Not Applicable (construction application)
5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: __________ ☐ Previously Submitted, Date ___________
   ☒ Not Applicable
6. Compliance Demonstration Reports/Records:
   ☐ Attached, Document ID: __________
   Test Date(s)/Pollutant(s) Tested: ___________________________

   ☐ Previously Submitted, Date: _______
   Test Date(s)/Pollutant(s) Tested: ___________________________

   ☐ To be Submitted, Date (if known): __________
   Test Date(s)/Pollutant(s) Tested: ___________________________

   ☒ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute:
   ☐ Attached, Document ID: __________ ☒ Not Applicable

## I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

**Additional Requirements for Air Construction Permit Applications**

| | |
|---|---|
| 1. | Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)):<br>☒ Attached, Document ID: PSD Report ☐ Not Applicable |
| 2. | Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.):<br>☐ Attached, Document ID: ____ ☒ Not Applicable |
| 3. | Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only)<br>☐ Attached, Document ID: ____ ☒ Not Applicable |

**Additional Requirements for Title V Air Operation Permit Applications**

| | |
|---|---|
| 1. | Identification of Applicable Requirements:<br>☐ Attached, Document ID: ____ |
| 2. | Compliance Assurance Monitoring:<br>☐ Attached, Document ID: ____ ☐ Not Applicable |
| 3. | Alternative Methods of Operation:<br>☐ Attached, Document ID: ____ ☐ Not Applicable |
| 4. | Alternative Modes of Operation (Emissions Trading):<br>☐ Attached, Document ID: ____ ☐ Not Applicable |

**Additional Requirements Comment**