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DIVISION OF AIR
RESOURCE MANAGEMENT

APPLICATION FOR PSD AIR CONSTRUCTION PERMIT MODIFICATION

Project No.:
0550061-002-AC-PSD
46A

HIGHLANDS ETHANOL, LLC
HIGHLANDS COUNTY, FLORIDA

ORIGINAL

PREPARED FOR:
HIGHLANDS ETHANOL, LLC
2202 N. WEST SHORE BOULEVARD
TAMPA, FLORIDA 33607

PREPARED BY:
AMEC ENVIRONMENT & INFRASTRUCTURE
511 CONGRESS STREET
PORTLAND, MAINE 04101

AUGUST 2012

bp

Dave

BP Biofuels North America, LLC
2202 North West Shore Boulevard
Suite 200
Tampa, FL 33607
USA

06 August 2012

Mr. David Read
Florida Department of Environmental Protection
Division of Air Resource Management
2600 Blair Stone Road, MS #5505
Tallahassee, FL 32399-2400

Re: Application to Modify PSD Permit for Proposed BP Biofuels – Highlands Facility

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Dear Mr. Read: project NO, 0550061-003-AC-PSD 406A

BP Biofuels – Highlands, an affiliate of BP Biofuels North America LLC, is pleased to submit the enclosed application for modification of Prevention of Significant Deterioration (PSD) Air Permit No. 0550061-001-AC and accompanying fee payment of $250 for the construction of the BP Biofuels - Highlands facility. As we discussed in our pre-application meeting on 18 April 2012 and during subsequent conference calls, since the issuance of the PSD Air Permit to Highlands Ethanol, LLC on 22 March 2010, BP Biofuels North America LLC has completed the acquisition of Verenium Biofuels and all its assets, including Highlands Ethanol, LLC. Following the acquisition, the proposed Highlands Ethanol facility was rebranded as BP Biofuels – Highlands and certain aspects of the facility were redesigned. BP Biofuels – Highlands is a new cellulosic ethanol production facility currently under construction in Highlands County near the intersection of State Route 70 and State Route 721.

As instructed at the 18 April 2012 pre-application meeting, we are hereby providing you with the electronic copy of the application in Adobe Portable Document Format (PDF). In addition, we are providing you with an identical hard copy for your records, which was sent via FedEx to the address listed above.

Because the proposed project is subject to the requirements of the United States Environmental Protection Agency's (USEPA's) Prevention of Significant Deterioration (PSD) rules, which are implemented by 61-212.400, Florida Administrative Code (F.A.C.) of FDEP's regulations, potential emissions from the proposed project will exceed the major source threshold for non-biogenic greenhouse gas (GHG) carbon dioxide equivalent (CO_2e) of 100,000 tpy. Therefore PSD review and application of Best Available Control Technology (BACT) is required for all criteria pollutants.

The enclosed permit application contains all of the required information for PSD review under 62-212.400 F.AC. as follows:

- Description of the proposed facility, processes, and equipment;
- Emissions characterization;
- Regulatory review;
- Control technology review;

- Source impact analysis;
- Air quality analysis;
- Additional impact analyses; and
- Completed permit application form (DEP Form No. 62-210.900(1)).

While BP Biofuels – Highlands has prepared an application that is based on the best available engineering data to date, we ask that FDEP recognize that final engineering design and vendor selection have not yet occurred. Therefore, it is possible that some design details and/or supporting information requested on the application form are not yet available or are subject to change. We respectfully request that application review commence and that a condition be included in the permit as is deemed necessary to supply final engineering information.

While the site is not currently supplied with natural gas, Florida Gas Transmission (FGT) has completed the construction of the West Leg Extension (WLE), a pipeline along the north side of State Route 70 and adjacent to the BP Biofuels – Highlands site. We are currently negotiating an interconnection agreement with FGT that will include the installation of a service connection that will supply the facility with natural gas from the WLE pipeline.

BP Biofuels – Highlands notes that the attached application shows a reduction in the potential emissions of all criteria pollutants when compared to the currently permitted allowable emissions. Federal Land Managers (FLMs) had determined that the previous application sufficiently demonstrated insignificant impacts on Federal Class I areas, with the nearest Class I area being the Everglades National Park at a distance of 154 km. The application package being submitted under this cover includes an anlaysis performed in accordance with FLM procedures that confirms that the facility will not impact Federal Class I areas. Because this application presents a reduction in potential criteria pollutant emissions for the facility and is not a major modification in that respect, BP Biofuels – Highlands assumes that FLM contact is not required. We would be happy to initiate contact with the FLMs should you advise otherwise.

This permit application represents a construction permit application only. BP Biofuels – Highlands is not requesting concurrent construction and operating permit review. We understand that a Title V permit application must be submitted 90 days prior to the expiration date of the facility's preconstruction permit but no later than 180 days after commencing operation. We will submit a Title V permit application, including Compliance Assurance Monitoring (CAM) plan, as necessary, at the required time.

We are excited about locating the first ever commercial scale cellulosic ethanol facility within the State of Florida, and we look forward to working with you through the permitting process. Should you have any questions, or require any additional information, please do not hesitate to contact me at (813) 574-0622 or our environmental consultant, Mr. Jeff Harrington of AMEC at (207) 828-2642.

Sincerely,

Kyle Kekeisen
Project Analyst, Commercial Development

cc: R. Perry – BP Biofuels
J. Harrington - AMEC

TABLE OF CONTENTS

Appendices

EXECUTIVE SUMMARY

BP Biofuels North America LLC is proposing to construct the Highlands Ethanol facility, a cellulosic ethanol production facility that will be located on 95.7 acres of land in southeastern Highlands County, Florida, near the community of Brighton. This state-of-the-art facility will have a nameplate production capacity of approximately 36 million gallons of cellulosic ethanol per year, using dedicated energy crop feedstocks, such as energy cane, energy grass, and napiergrass grown on nearby farmland. Verenium Corporation, the previous owner of Highlands Ethanol, received an air construction permit (# 0550061-001-AC) which expires on December 31, 2014. This application is for a revised air construction permit for the facility under the new ownership of BP Biofuels North America LLC.

The demand for fuel grade ethanol has increased ten-fold in the past twenty years in the United States. Fuel grade ethanol is used primarily as an "oxygenate" and a source of octane in gasoline, and has been identified in national strategies as a means to reduce our country's dependence on foreign energy supplies. Historically, ethanol has been a key ingredient of oxygenated gasolines required to attain performance targets required in fuels regulations and clean air programs. Ethanol blending in the US gasoline pool increased significantly as the use of other gasoline additives such as methyl tert-butyl ether (MTBE) was phased out. Although the majority of fuel ethanol produced in the US to date has been made from corn (1st Generation Ethanol production), this facility represents one of the first commercial scale facilities utilizing 2nd Generation, cellulosic technology. The energy inputs and carbon footprint of the cellulosic biofuels industry will be significantly lower than those of 1st Generation production facilities.

The federal Energy Independence and Security Act of 2007 (EISA) requires that 36 billion gallons per year of biofuels are blended into the US liquid transportation fuel pool by the year 2022. Within that overall mandate structure, EISA contains a nested sub-mandate that requires 16 of the 36 billion gallons be comprised of cellulosic biofuels. The structure set by EISA established a significant market demand for scale production of cellulosic biofuels. There are a number of advantages to using cellulosic biomass as the raw material for biofuels as compared to current industry feedstocks:

- increased yield of ethanol per acre of cropland,
- use of a non-food crop,
- relatively low feedstock cost, and
- diversifies the economic benefits of biofuels to more regions in the US.

Benefits of the proposed project include:

- The creation of an estimated 200 full time jobs at the farm and facility. These will be permanent high-paying jobs for skilled workers.

- BP is also working with the local community colleges to develop job training programs that will prepare the local work force supporting the Highlands Facility.
- Construction activities, at peak, will employ approximately 600 to 800 people during the estimated 18 to 24 month construction period. The estimated construction-related cost of the facility will be in the hundreds of millions of dollars, including labor benefits, overhead and taxes, and the purchase of local supplies, services, and consumables. The proposed project should not require any additional infrastructure for Highlands County or other local communities, and will have a minimal impact on the municipal services which will be supported by the tax dollars paid by the facility.
- Property values are not expected to be negatively impacted. The proposed facility will be located on a 95.7 acre site surrounded by agricultural land. There are no residential properties located within one mile of the site.
- The project will generate tax revenue for the county and state economies.

Project Overview

Cellulosic ethanol is produced by converting the abundant cellulose and hemicellulose in biomass to sugars that are then fermented to produce ethanol. Expected ethanol yields from cellulosic biomass crops, based on BP Biofuels' process, are on the order of 1400-1800 gallons per acre. The ethanol currently produced in the United States is produced from food based feedstock, primarily corn. Ethanol yields from corn crops are on the order of 400 gallons per acre, or less than one-quarter of the yield per acre expected for cellulosic ethanol.

The proposed ethanol production capacity of approximately 36 million gallons per year is based on an expected operating schedule of 8,000 hours per year. The project will be permitted at an operating capacity of 39.42 million gallons per year to allow for an operating schedule of 8,760 hours per year. The ethanol is required to be denatured with gasoline, with a denaturant content ranging from 2% to 5% by volume. For air permitting purposes, maximum potential emissions occur when the denaturant content is 5%. The capacity of the facility to produce this ethanol-gasoline blend, referred to as E95, will amount to 41.49 million gallons when accounting for the denaturant.

Facility Emissions

Emissions of regulated New Source Review (NSR) pollutants and Hazardous Air Pollutants (HAPs) were calculated. Annual and short-term emissions (durations of 24 hours or less) were calculated for comparison to regulatory thresholds and to meet dispersion modeling requirements. Emissions from point sources and fugitive sources were quantified separately. Point sources are emission sources that are vented through a stack or vent. Fugitive sources are emission sources that have no specific emission point.

The facility will include one biomass boiler that will burn stillage cake and biosolids, byproducts of the process, as well as biogas generated by an anaerobic digester used to recover energy from the facility's thin stillage. The biomass boiler will also be equipped to combust natural gas. The biomass boiler will supply baseload steam to the ethanol production processes and will also supply steam to a steam turbine generator with a capacity of producing 7.6 megawatts (MW) of power to be used exclusively at the facility. The facility will also include a peaking boiler fired with natural gas that will supply steam to the ethanol production processes during peak process demand periods and auxiliary steam when the biomass boiler is down.

A summary of calculated potential emissions by emission source is provided in Table 1. In addition to the criteria pollutant emissions and total hazardous air pollutant (HAP) emissions presented in Table 1, total greenhouse gas (GHG) and non-biogenic GHG emissions from the facility were calculated to be 523,308 tons per year (tpy) of carbon dioxide equivalent (CO_2e) and 182,834 tpy CO_2e, respectively.

Table 1. Summary of Calculated Potential Emissions, Highlands Ethanol

Process	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)	NO_X (tpy)	CO (tpy)	VOC (tpy)	HAP (tpy)
Thermal Oxidizer (RTO)	0.03	0.03	0.07	0.46	0.49	21.44	8.70
Product/Denaturant Stg.	--	--	--	--	--	1.18	0.07
Misc. Storage Silos	4.5	4.5	--	--	--	--	--
Biogas Backup Flare	0.002	0.002	0.0005	0.055	0.30	0.11	--
Cooling Tower	1.5	1.5	--	--	--	9.2	0.5
Steam Production	13.5	13.5	73.3	109	134	6.50	7.3
Emergency Engines	0.90	0.90	0.033	25.8	15.7	2.87	0.08
Subtotal, Point Sources	**20.4**	**20.4**	**73.4**	**135.5**	**150.1**	**41.3**	**16.6**
Stillage Loadout	--	--	--	--	--	8.4	--
Equipment Leaks	--	--	--	--	--	19.6	0.98
Roadway Emissions	0.43	0.057	--	--	--	--	--
Subtotal, Fugitive Sources	**0.43**	**0.057**	**--**	**--**	**--**	**28.0**	**0.98**
Total	***20.8***	***20.4***	***73.4***	***135.5***	***150.1***	***69.3***	***17.6***

Applicable Requirements

The proposed project is required to obtain a revised air construction permit from the Florida Department of Environmental Protection (FDEP) before equipment can be constructed. Additionally, the project is subject to the requirements of the United States Environmental Protection Agency's (USEPA's) Prevention of Significant Deterioration (PSD) rules, which are implemented by 62-212.400, Florida Administrative Code (F.A.C.) of the FDEP's regulations.

These regulations impose Best Available Control Technology (BACT) emission control requirements on the proposed facility. In addition, the Highlands Ethanol project is required to demonstrate compliance with the USEPA's National Ambient Air Quality Standards (NAAQS), and USEPA's and FDEP's ambient allowable increments. This application for the revised air construction permit demonstrates that the Highlands Ethanol facility will meet the control technology requirements and will comply with ambient air quality standards and allowable ambient increments.

The proposed facility will be subject to the following regulations (see Section 4 for additional analysis):

- Prevention of Significant Deterioration (PSD)
- New Source Performance Standards (NSPS) at 40 CFR 60:
  - Subpart A, General Provisions
  - Subpart Db *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units > 100 MMBtu*
  - Subpart Dc *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units < 100 MMBtu*
  - Subpart Kb *Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels)*
  - Subpart VVa *Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry*
  - Subpart IIII *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*
- New Source Emission Standards for Hazardous Air Pollutants (NESHAPs) at 40 CFR 63:
  - Subpart ZZZZ *National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*
  - Subpart JJJJJJ National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers – Area Sources
- 40 CFR 82 Stratospheric Ozone Protection Provisions

The project is not subject to the following provisions (see Section 4 for additional analysis):

- 40 CFR 60 Subparts K, Ka, DD, VV, XX, III, NNN, RRR, and CCCC
- 40 CFR 63 Subparts B, F, G, H, I, Q, R, Y, OO, PP, WW, TT, UU, VV, YY, EEEE, FFFF, and DDDDD
- Acid Rain Permit Program at 40 CFR 72 and 62-214, F.A.C.

- Cross State Air Pollution Rule (CSAPR) at 40 CFR 97
- NO_X Budget Program at 40 CFR 96 and 40 CFR 97
- Clean Air Interstate Rule at 40 CFR 96 and 40 CFR 97, 62-296.470, F.A.C.
- Chemical Accident Prevention at 40 CFR 68 with exception of general duty provisions

It should be noted that Compliance Assurance Monitoring (CAM) requirements will be addressed in the Title V permit application and not in the PSD preconstruction permit revision application.

Control Technology Assessment

Based on the calculated potential emissions for the Highlands Ethanol project and a review of the regulations that consequently apply to the project, Table 2 provides a listing of the emission sources that will emit the pollutants subject to BACT.

Table 2: Emission Sources Subject to BACT

	Pollutant Emitted Subject to BACT Review						
Sources	**VOC**	**NO_X**	**CO**	**SO_2**	**PM_{10}**	**$PM_{2.5}$**	**GHG**
Point Sources							
Liquid/Solid Separation	•						
Fermentation/Distillation/Propagation	•						•
Product/Denaturant Storage	•						
Product Loadout	•						
Miscellaneous Storage Silos					•	•	
Anaerobic Digestion and Backup Flare	•			•			•
Cooling Tower	•				•	•	
Steam Production	•	•	•	•	•	•	•
Emergency Engines	•	•	•	•	•	•	•
Fugitive Sources							
Stillage Loadout	•						
Equipment Leaks	•						
Roadway Emissions					•	•	

The following paragraphs summarize the proposed emissions control technology and emission limits by pollutant.

Volatile Organic Compounds (VOCs)

Highlands Ethanol proposes to utilize a regenerative thermal oxidizer (RTO) achieving BACT control of 99 percent removal of VOC emissions from several process areas, including liquid/solid separation, fermentation, propagation, distillation, ethanol shift storage, and product loadout.

Internal floating roofs will be installed to control VOC emissions from the product storage tank and denaturant storage tank.

An anaerobic digester used to recover energy from the thin stillage will produce biogas (predominantly methane) that will be combusted in the biomass boiler. During times when the biomass boiler is unavailable, the biogas emissions will be controlled with a flare having a rated capacity of 100 million British thermal units per hour (MMBtu/hr).

Highlands Ethanol proposes to utilize good combustion practices to control VOC emissions from the biomass boiler and peaking boiler. The proposed VOC BACT emission limit for the biomass boiler is 0.005 pounds per million British thermal units (lb/MMBtu). The proposed VOC BACT emission limit for the peaking boiler is 0.0014 lb/MMBtu.

The emergency generators and the fire pump will utilize good combustion practices, use ultra-low sulfur diesel (ULSD), and limit operation for maintenance and testing purposes to no more than 100 hours per year as well as limit total operation to no more than 500 hours per year. The proposed VOC BACT emission limits for the emergency units are 0.64 grams per kilowatt hour (g/kW·hr) for the emergency generators and 0.3 g/hp·hr for the fire pump.

Handling of the stillage cake as it is transferred from dewatering to the boilers will be performed entirely within a closed system except for the conveyor system. VOC emissions will occur from the evaporation of trace organics dissolved in the water fraction and therefore maintenance of the stillage cake at ambient temperature will reduce the potential for fugitive VOC emissions and represents BACT.

BACT for equipment leaks is the establishment of a leak detection and repair (LDAR) program in compliance with 40 CFR 60, Subpart VVa. Similarly, VOC emissions from the cooling tower are the result of process fluid leaks from heat exchangers into cooling water. BACT for leaks into cooling water is the establishment of a monitoring program for VOCs in cooling water to allow for maintenance of equipment leaks.

Particulate Matter (PM)

Highlands Ethanol intends to install bin vent filters on miscellaneous chemical storage silos. Highlands Ethanol is proposing a $PM_{10}/PM_{2.5}$ BACT emission limit of 0.005 grains per dry standard cubic foot (gr/dscf) for the miscellaneous storage silos.

Highlands Ethanol proposes to install a cooling tower with a 0.0005% drift eliminator, which represents the top level of control and BACT for $PM_{10}/PM_{2.5}$.

Fabric filters, the top level of BACT control will be installed on the biomass boiler. Highlands Ethanol is proposing a $PM_{10}/PM_{2.5}$ BACT emission limit of 0.01 lb/MMBtu (filterable, based on Method 5) and 0.05 lb/MMBtu (total, including condensables).

BACT for particulate matter emissions from the peaking boiler will be the use of natural gas and good combustion practices. The proposed $PM_{10}/PM_{2.5}$ BACT emission limit is 0.004 lb/MMBtu (filterable, based on Method 5).

The emergency engines and the fire pump will utilize good combustion practices, use ULSD, and limit operation for maintenance and testing purposes to no more than 100 hours per year as well as limit total operation to no more than 500 hours per year. The proposed $PM_{10}/PM_{2.5}$ BACT emission limits are 0.2 g/kW·hr for the emergency generators and 0.15 grams per horsepower hour (g/hp·hr) for the fire pump.

Nitrogen Oxides (NO_X)

The proposed biomass boiler will use fluidized bed combustion technology. Combustion in a fluidized bed unit results in inherently low NO_X emissions compared to other solid-fuel boiler designs resulting in emission levels similar to a traditional boiler design employing combustion controls. In addition, Highlands Ethanol proposes to install selective non-catalytic reduction (SNCR) to further reduce NO_X emissions from the biomass boilers. Highlands Ethanol proposes a NO_X BACT emission limit of 0.08 lb/MMBtu.

Highlands Ethanol proposes to install a peaking boiler with low NO_X burners and flue gas recirculation (FGR), which is the highest level of combustion controls available. The proposed NO_x BACT emission limit is 0.035 lb/MMBtu.

The emergency engines and the fire pump will meet NSPS Subpart IIII, utilize good combustion practices, use ULSD, and limit operation for maintenance and testing purposes to no more than 100 hours per year as well as limit total operation to no more than 500 hours per year. The proposed NO_X BACT emission limits are 5.76 g/kW·hr for the emergency generators and 2.7 g/hp·hr for the fire pump.

Sulfur Dioxide (SO_2)

Highlands Ethanol proposes to utilize limestone injection and a dry scrubber to reduce SO_2 emissions from the biomass boiler. Highlands Ethanol proposes an SO_2 BACT emission limit of 0.06 lb/MMBtu based on a 30-day rolling average. Because of the potential for variability in short-term levels of sulfur in the fuel, Highlands Ethanol further proposes SO_2 BACT emission limits of 0.12 lb/MMBtu (24-hour rolling average) and 0.14 lb/MMBtu (3-hour block average).

During periods when the biomass boiler is unavailable and/or the biogas flow rate exceeds the biomass boiler capacity, the biogas will be combusted in a backup flare. Control strategies for

SO_2 emissions from a flare are limited to biogas desulfurization, which can be achieved through a wide range of technologies. SO_2 BACT for the backup flare was determined to be installation of a scrubber system that removes 98% of the H_2S in the biogas.

Natural gas will be fired in the peaking boiler and will have a SO_2 BACT emission limit of 0.0056 lb/MMBtu, based on FDEP's presumed natural gas sulfur content of 0.02 gr/scf.

Highlands Ethanol proposes to utilize ULSD in the fire pump engine and emergency generators. These units will be new units and will be required to meet the NSPS for internal combustion engines (40 CFR 60, Subpart IIII) as well. Therefore BACT for SO_2 emissions from these units is good combustion practices, use of ULSD, and limit operation to no more than 100 hours per year for maintenance and testing purposes as well as limit total operation to no more than 500 hours per year.

Carbon Monoxide (CO)

Highlands Ethanol plans to utilize good combustion practices to control CO emissions from the biomass boiler and peaking boiler. The proposed CO BACT emission limit for the biomass boiler is 0.1 lb/MMBtu (30-day rolling). Highlands Ethanol proposes a CO BACT emission limit of 0.037 lb/MMBtu for the peaking boiler.

The emergency engines and the fire pump will utilize good combustion practices, use ULSD, and limit operation for maintenance and testing purposes to no more than 100 hours per year as well as limit total operation to no more than 500 hours per year. The proposed CO BACT emission limits are 3.5 g/kW·hr for the emergency generators and 2.6 g/hp·hr for the fire pump.

Greenhouse Gases (GHGs)

GHGs are emitted from the project through combustion and fermentation. The vast majority of the GHGs are comprised of carbon dioxide (CO_2) with other GHGs (N_2O, CH_4, etc.) emitted in much smaller amounts.

The reduction of primary GHG emissions through the use of good fermentation practices and the reduction of secondary GHG emissions through the application of energy efficiency measures, water recycling and beneficial use of co-products were determined to be BACT for the fermentation process.

In accordance with EPA's guidance, GHG BACT for the biomass boiler is the firing of stillage cake, biosolids and biogas as the primary fuels with supplementation via natural gas. The boiler will be operated as a cogeneration unit, providing both steam and electricity to the process, which is the most efficient form of thermal energy use. The boiler will meet BACT for good combustion practices for CO and VOCs, which also satisfies GHG BACT for several recently approved projects.

To satisfy GHG BACT, the peaking boiler will be fired with natural gas and will operate to provide peak steam loads or auxiliary steam when steam is not available from the biomass boiler. BACT for GHG emissions will be implementation of good combustion practices as noted previously to meet CO and VOC BACT requirements.

The firing of biogenic fuel is GHG BACT for the biogas backup flare.

The emergency engines and the fire pump will only operate for readiness testing and during emergencies. GHG BACT for these engines is limited operation for maintenance and testing purposes to no more than 100 hours per year as well as total operation to no more than 500 hours per year.

Ambient Impact Analysis

An ambient air quality impact analysis was conducted for the proposed project. Emission rates, exhaust parameters, and stack parameters were obtained or calculated, and wind-direction specific building dimensions were calculated with USEPA's BPIPPRM computer program. A modeling protocol was prepared that described the selected dispersion model, land use, receptor grids, and meteorological data used.

The significant impact analysis was completed per USEPA guidance. Dispersion modeling was performed to determine the maximum impact operating scenario for the proposed combustion equipment. The "100% load" operating scenario was selected for further analysis for all pollutants and averaging periods. In several cases, the 75% load was also selected for further analysis. The predicted concentrations for the selected operating scenarios were then compared to Significant Impact Levels (SILs). Predicted concentrations were less than SILs for CO and Pb, demonstrating compliance with NAAQS and allowable increments. Because predicted concentrations were less than SILs for CO and Pb, interactive source modeling was not required. In contrast, predicted concentrations of SO_2, PM_{10}, $PM_{2.5}$, and NO_2 were greater than SILs.

Interactive source modeling was performed for SO_2, PM_{10}, $PM_{2.5}$, and NO_2. Background air quality concentrations were identified based on data collected at monitoring sites in southern Florida. FDEP provided a database of interactive sources located in southern Florida for input to the dispersion model. The interactive source analysis demonstrates that the proposed project will be in compliance with ambient air quality standards and ambient increment standards.

Highlands Ethanol is requesting an exemption from pre-construction monitoring requirements. Predicted concentrations of NO_2, CO, and Pb were less than Significant Monitoring Concentrations (SMC). In the cases of SO_2, PM_{10}, and $PM_{2.5}$, existing data from southern Florida were deemed to be conservatively representative of background air quality in Highlands County.

An assessment of the potential impacts on Class I areas by the proposed project was performed in accordance with Federal Land Manager (FLM) guidance. The analysis confirms the FLMs' 2009 conclusion that no further analysis of Class I areas is required. The FLMs' letters documenting this conclusion are on file at FDEP.

Finally, an additional impacts analysis was performed. Growth, visibility impairment, impacts to soils and vegetation, and air toxics were addressed. The analysis demonstrated that resulting impacts are minimal.

Conclusions

The purpose of this revised air permit application is to demonstrate that the Highlands Ethanol project will include the required air emission controls and will comply with ambient air quality standards and ambient increment standards. This application provides an emissions inventory and other information required to identify applicable requirements, a control technology assessment that identifies BACT emission controls, and a dispersion modeling analysis that demonstrates compliance with ambient air quality standards.

1.0 INTRODUCTION

BP Biofuels North America LLC is proposing to construct the Highlands Ethanol facility, a cellulosic ethanol production facility that will be located on 95.7 acres of land in southeastern Highlands County, Florida, near the community of Brighton. This state-of-the-art facility will have a nameplate production capacity of approximately 36 million gallons of cellulosic ethanol per year, using dedicated energy crop feedstocks, such as energy cane, energy grass, and napiergrass grown on nearby farmland. Verenium Corporation, the previous owner of Highlands Ethanol, received an air construction permit (# 0550061-001-AC) which expires on December 31, 2014. This application is for a revised air construction permit for the facility under the new ownership of BP Biofuels North America LLC.

The demand for fuel grade ethanol has increased ten-fold in the past twenty years in the United States. Fuel grade ethanol is used primarily as an "oxygenate" and a source of octane in gasoline, and has been identified in national strategies as a means to reduce our country's dependence on foreign energy supplies. Historically, ethanol has been a key ingredient of oxygenated gasolines required to attain performance targets required in fuels regulations and clean air programs. Ethanol blending in the US gasoline pool increased significantly as the use of other gasoline additives such as methyl tert-butyl ether (MTBE) was phased out. Although the majority of fuel ethanol produced in the US to date has been made from corn (1st Generation Ethanol production), this facility represents one of the first commercial scale facilities utilizing 2nd Generation, cellulosic technology. The energy inputs and carbon footprint of the cellulosic biofuels industry will be significantly lower than those of 1st Generation production facilities.

The federal Energy Independence and Security Act of 2007 (EISA) requires that 36 billion gallons per year of biofuels are blended into the US liquid transportation fuel pool by the year 2022. Within that overall mandate structure, EISA contains a nested sub-mandate that requires 16 of the 36 billion gallons be comprised of cellulosic biofuels. The structure set by EISA established a significant market demand for scale production of cellulosic biofuels. There are a number of advantages to using cellulosic biomass as the raw material for biofuels as compared to current industry feedstocks:

- increased yield of ethanol per acre of cropland,
- use of a non-food crop,
- relatively low feedstock cost, and
- diversifies the economic benefits of biofuels to more regions in the US.

Benefits of the proposed project include:

- The creation of an estimated 200 full time jobs at the farm and facility. These will be permanent high-paying jobs for skilled workers.

- BP is also working with the local community colleges to develop job training programs that will prepare the local work force supporting the Highlands Facility.
- Construction activities, at peak, will employ approximately 600 to 800 people during the estimated 18 to 24 month construction period. The estimated construction-related cost of the facility will be in the hundreds of millions of dollars, including labor benefits, overhead and taxes, and the purchase of local supplies, services, and consumables. The proposed project should not require any additional infrastructure for Highlands County or other local communities, and will have a minimal impact on the municipal services which will be supported by the tax dollars paid by the facility.
- Property values are not expected to be negatively impacted. The proposed facility will be located on a 95.7 acre site surrounded by agricultural land. There are no residential properties located within one mile of the site.
- The project will generate tax revenue for the county and state economies.

Cellulosic ethanol is produced by converting the abundant cellulose and hemicellulose in biomass to sugars that are then fermented to produce ethanol. Expected ethanol yields from cellulosic biomass crops, based on BP Biofuels' process, are on the order of 1400-1800 gallons per acre. The ethanol currently produced in the United States is produced from food based feedstock, primarily corn. Ethanol yields from corn crops are on the order of 400 gallons per acre, or less than one-quarter of the yield per acre expected for cellulosic ethanol.

The proposed ethanol production capacity of approximately 36 million gallons per year is based on an expected operating schedule of 8,000 hours per year. The project will be permitted at an operating capacity of 39.42 million gallons per year to allow for an operating schedule of 8,760 hours per year. The ethanol is required to be denatured with gasoline, with a denaturant content ranging from 2% to 5% by volume. For air permitting purposes, maximum potential emissions occur when the denaturant content is 5%. The capacity of the facility to produce this ethanol-gasoline blend, referred to as E95, will amount to 41.49 million gallons when accounting for the denaturant.

The proposed project is required to obtain a revised air construction permit from the Florida Department of Environmental Protection (FDEP) before it can be constructed. Additionally, the project is subject to the requirements of the United States Environmental Protection Agency's (USEPA's) Prevention of Significant Deterioration (PSD) rules, which are implemented by 62-212.400, Florida Administrative Code (F.A.C.) of the FDEP's regulations.

The purpose of this revised air permit application is to provide the technical information required by the FDEP's air permitting program, and demonstrate that the proposed facility will be in compliance with regulations related to ambient air quality. As such, this application provides:

- A description of the proposed project configuration (Section 2);

- An inventory of maximum potential emissions resulting from the project (Section 3);
- An analysis of applicable regulatory requirements (Section 4);
- A Best Available Control Technology (BACT) assessment for the project (Section 5);
- An ambient air quality impact assessment (Section 6);
- Completed air permit application forms (Appendix A);
- Detailed emissions calculations (Appendix B);
- A detailed site plan (Appendix C);
- USEPA Applicability Determinations for New Source Performance Standards (NSPS) Subparts NNN and RRR (Appendix D);
- Data from USEPA's RACT/BACT/LAER Clearinghouse (RBLC) (Appendix E);
- A summary of dispersion model input and output files (Appendix F);
- A tabulation of modeling inputs for interactive sources in the vicinity (Appendix G); and
- A listing of exempt and insignificant emission units (Appendix H).

To facilitate the cross-referencing between the existing PSD permit and the information presented herein, the following table has been provided that highlights the differences in the process areas.

Emission Unit ID	Existing Permit	Modified Permit
001	Feedstock Receiving	Feedstock Receiving
002	Hydrolysis, Liquid/Solid Separation	Obsolete, emissions now vented to RTO
003	Fermentation, Distillation, Propagation	RTO (includes fermentation, distillation, propagation, liquid/solid separation, product loadout)
004	Solids Separation, Dewatering, and Loadout	Solids separation, dewatering, and loadout
005	Denaturant and Product Storage	Denaturant and Product Storage
006	Product Loadout and Flare	Obsolete, emissions now vented to RTO
007	Wastewater Treatment, Biogas Conditioning, and Flare	Anaerobic Digestion, Biogas Conditioning, and Biogas Backup Flare
008	Biomass Boiler No. 1	Biomass Boiler
009	Biomass Boiler No. 2	Obsolete
010	Backup Gas Boiler	Peaking Gas Boiler
011	Cooling Tower	Cooling Tower
012	Misc. Storage Silos	Misc. Storage Silos

Emission Unit ID	Existing Permit	Modified Permit
013	Misc. Storage Tanks	Misc. Storage Tanks
014	Emergency Generators	Emergency Generators
015	Fire Pump	Fire Pump
016	Fugitive VOC Equipment Leaks	Fugitive VOC Equipment Leaks

2.0 PROJECT DESCRIPTION

Highlands Ethanol is proposing to construct its facility in southeastern Highlands County, Florida, near the community of Brighton. This state-of-the-art facility will have a nameplate production capacity of approximately 36 million gallons of ethanol per year, using feedstocks of dedicated energy crops, such as energy cane, energy grasses, Napier grass, and others grown on adjacent farmland and elsewhere in the region.

This section provides a description of the project location (Section 2.1), and the proposed equipment to be installed for the project (Section 2.2).

2.1 Site Location

The proposed Highlands Ethanol commercial facility will be located on property previously owned by Lykes Bros., Inc., purchased by Highlands Ethanol, and approximately 2 miles east of the community of Brighton. The 95.7 acre site is surrounded entirely by Lykes Bros. property, with an easement allowing access to the site from State Route 70. The location of the site is presented in Figure 2-1.

The site is exceptionally flat, with terrain elevations ranging from 30 to 32 feet above mean sea level (AMSL). The facility will be constructed on additional fill material with a resulting base elevation of 36 feet AMSL. Terrain surrounding the site is generally flat with the highest elevation within 10 kilometers (km) of the site being 50 feet AMSL. This higher terrain is generally located along US Route 98 between the communities of Fort Basinger and Cornwell.

The proposed facility is located in the USEPA's Southwest Florida Intrastate Air Quality Control Region (AQCR), which is classified as attainment or unclassifiable for all criteria pollutants. The AQCR is classified as a Class II area with regard to available ambient increments.

The closest PSD Class I areas are the Everglades National Park (154 km) and the Chassahowitzka Wilderness Area (216 km). All other Class I areas are located at distances greater than 300 km from the facility with the next closest being the Okefenokee Wilderness Area in Georgia (386 km).

2.2 Summary of Proposed Facility

The proposed Highlands Ethanol project will have a nameplate ethanol production capacity of approximately 36 million gallons per year, based on an expected operating schedule of 8,000 hours per year. For permitting purposes, the availability of the plant is assumed to be 8,760 hours per year, resulting in an assumed operating capacity of 39.4 million gallons per year. Fuel ethanol is required to be denatured with gasoline. The capacity of the facility to produce this ethanol-gasoline blend, referred to as E95, will amount to 41.5 million gallons per year when accounting for the denaturant volume.

A process flow schematic of the proposed facility is provided in Figure 2-2. Facility processes include:

- Feedstock handling;
- Hydrolysis;
- Liquid/solid separation and neutralization;
- Fermentation, distillation, and propagation;
- Product and denaturant storage tanks;
- Product loadout;
- Miscellaneous storage tanks;
- Miscellaneous storage silos;
- Stillage loadout;
- Anaerobic digestion;
- Cooling tower;
- Steam production; and
- Emergency engines.

Air emissions will be produced by the proposed equipment. The basis for the calculation of emissions from the various processes is provided in Section 3. Detailed calculations of the emissions are provided in Appendix B. A site plan of the project is included in Appendix C.

2.2.1 Feedstock Handling

Feedstocks will be delivered to the facility by truck from the adjacent farmland. The feedstocks will be freshly harvested material with a high moisture content. The facility will be designed to receive 4,000 green tons per day (167 green tons per hour) of feedstock.

Upon receipt, the feedstock will be offloaded to one of three locations: (a) directly to the plant's feedstock hopper, (b) a conveyor feed system or (c) onto a feedstock day storage pad that is designed to hold 24 hours of harvested feedstock. Daytime delivery of feedstock is expected to occur at a rate faster than the design feedstock input rate of the facility (i.e., feedstock will generally be delivered during daylight hours but the plant will be running 24 hours per day, thus the day pad effectively serves as a surge pad). The feedstock will be conveyed from the day pad to the feedstock hopper at the plant. The day pad and much of the conveyor will be located on the farmland adjacent to the project site. The day pad will be roughly one acre in size and will improve operating safety at the site because the number of feedstock trailer hitching and unhitching operations will be significantly diminished.

HIGHLANDS ETHANOL LLC
5100 W. LEMON STREET SUITE 114
TAMPA, FLORIDA 33609

Bank of America
ACH R/T 063100277

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August 02, 2012

PAY TO THE ORDER OF FLORIDA DEPT OF ENVIRONMENTAL PROTECTION $250.00***

*** Two Hundred Fifty and 00/100*** DOLLARS

FLORIDA DEPT OF ENVIRONMENTAL PROTECTION
DIVISION OF AIR RESOURCE
MANAGEMENT
2600 BLAIR STONE ROAD, MS #
5505

MEMO

AUTHORIZED SIGNATURE

Details on Back.

Security Features Included

[redacted]

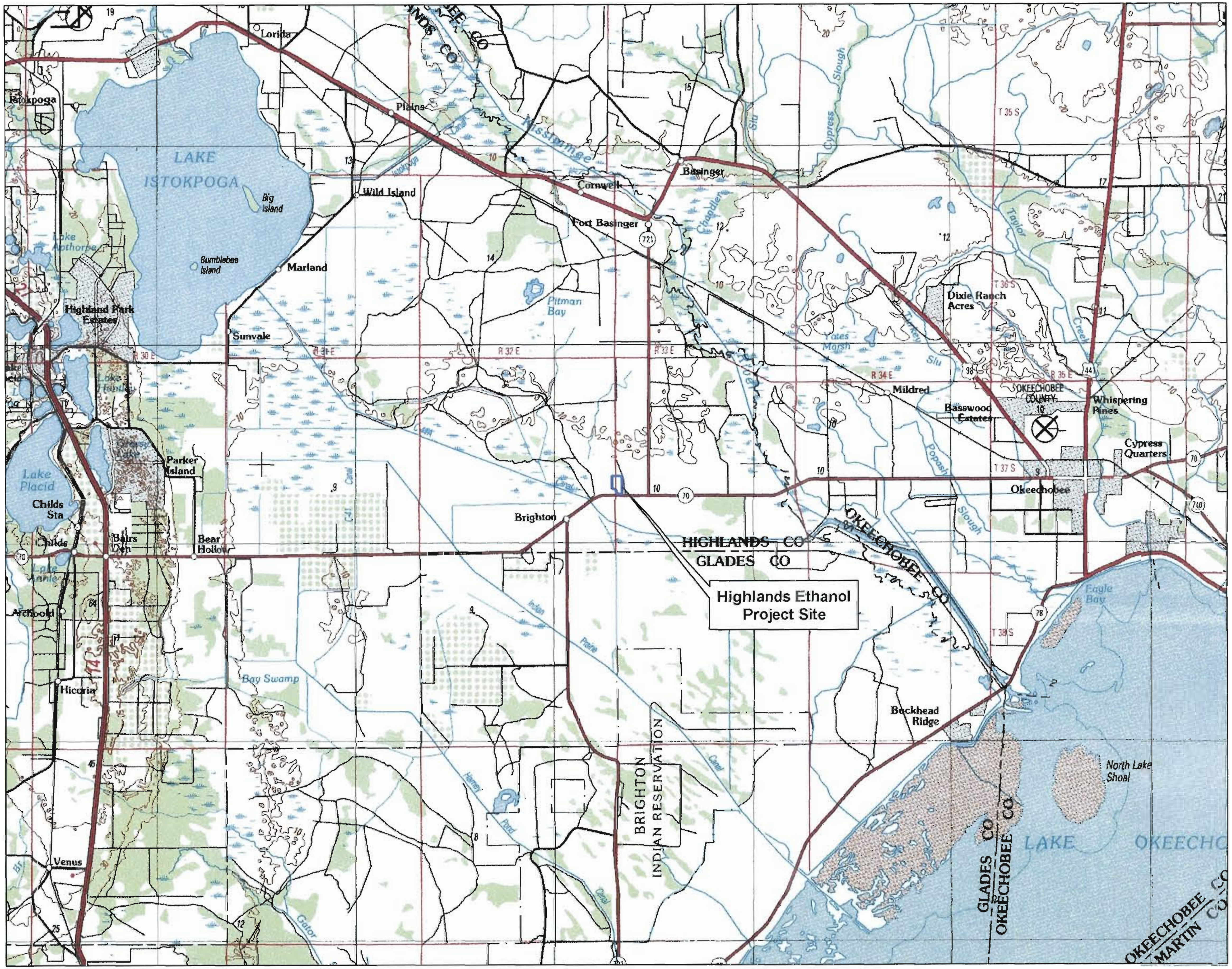
HIGHLANDS ETHANOL LLC 2569

Check 2569

Vendor : 5897, FLORIDA DEPT OF ENVIRONMENTAL PROTECTION

Invoice number	Invoice Date	Currency	Gross amount	Cash discount	Payment amount
App Fee PSD Air	7/31/2012	USD	250.00	0.00	250.00
Total					250.00

Vendor Payment App Fee PSD Air



LEGEND

Property Line

LOCATION MAP

NOTES & SOURCES

Map Projection: NAD 83, UTM Zone 17N, Meters
Basemap data from US Geologic Survey 1°x2° Series
Topographic Map Source: FL Land Boundary Information System

TITLE

Highlands Ethanol Site Location

0 2 Kilometers

amec

AMEC Environment & Infrastructure
Portland, Maine

FIGURE 2-1

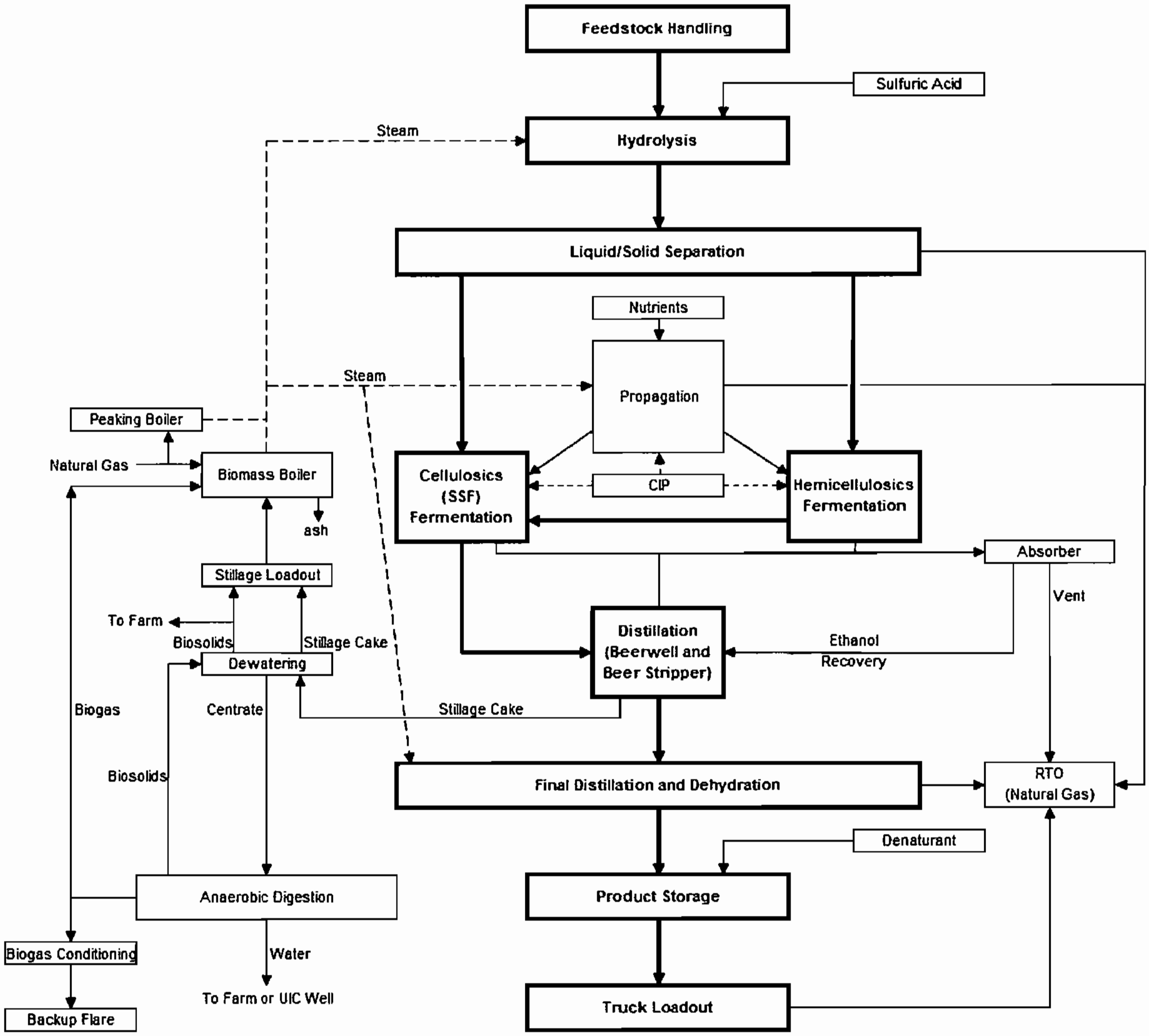


Figure 2-2
Process Flow Schematic, Highlands Ethanol

The project is also proposing to include a separate and larger medium-term storage pad adjacent to the day pad. The medium-term pad will accommodate 4 days of fresh feedstock material as well as excess bagasse from the feedstock handling process. Both fresh feedstock and bagasse would be delivered to the medium-term storage pad by truck. The medium-term storage pad will be roughly four acres in size. The medium-term storage pad will be used for production feedstock during times of inclement weather when harvesting and transportation of feedstock is prohibitive.

Because the storage pads and conveyor will be handling predominantly fresh feedstock material, fugitive emissions from these process areas are expected to be minimal. Nevertheless, the conveyor will be equipped with a cover and water sprays at drop points to be used as needed.

Feedstock will be loaded from the conveyor directly into the plant feedstock hopper and subsequently conveyed through a washing process. The feedstock will then be shredded, passed through a series of three roller mills and delivered to a bagasse storage silo for conveying to the hydrolysis step. Juice recovered from the roller mill operations will be pasteurized and used in the liquid-solid separation area for dilution of hydrolyzed bagasse. Excess bagasse that cannot be accommodated by the bagasse storage silo will be transferred to trucks/trailers and delivered to the medium-term storage pad. Best management practices will be employed at the excess bagasse transfer points to reduce the potential for fugitive dust emissions. Otherwise, the process from the feedstock hopper through to the bagasse silo is analogous to those steps in a sugar mill and fugitive dust emissions are expected to be minimal due to the moisture inherent to the process.

The feedstock handling area is considered to be an insignificant source of air emissions. Further, Highlands Ethanol notes that the existing permit includes accommodation for storage and handling of supplemental biomass for the biomass boiler. The supplemental biomass drove a requirement for covered conveyors and for dust collectors at drop and transfer points associated with the supplemental biomass. These will no longer be necessary because supplemental biomass will not be utilized by the project, and therefore the conditions can be removed from the permit.

2.2.2 Hydrolysis

The bagasse will be delivered from the bagasse silo via conveyor to a live bottom bin that feeds a plug screw and subsequently a steam mixing conveyor. The bagasse is subject to increasing temperature and pressure and mixed with dilute sulfuric acid during these steps in preparation for introduction to a digester for acid hydrolysis. The resulting slurry will consist of cellulose/lignin solids mixed with a liquid fraction containing a variety of pentoses (i.e., xylose, arabinose, and others) and hexoses (i.e., glucose, mannose, galactose, and others). At the outlet of the hydrolyzer, pressure is released and the resulting flash steam is condensed and sent to the anaerobic digester.

2.2.3 Liquid/Solid Separation and Neutralization

The slurry is separated into liquid and solid fractions using three screw presses arranged in a parallel configuration. The resulting cellulose/lignin solids stream, which has high water content, will be diluted with hemicellulosic fermentation beer and neutralized with magnesium hydroxide in a cake mixer. The resulting liquid filtrate stream, which contains most of the hemicellulosic sugars, will be neutralized with magnesium hydroxide in a neutralization tank and subsequently mixed with aqueous ammonia to allow for survival of the fermentation microorganisms. The entire process is operated at elevated temperature and pressure. Emissions from the process will be collected and exhausted directly to a regenerative thermal oxidizer (RTO).

2.2.4 Fermentation, Distillation, and Propagation

A set of six hemicellulosic fermentation vessels will be used to ferment the hemicellulosic sugars. The sugars will be fermented with a proprietary microorganism to produce a dilute ethanol beer. The fermentations will occur in batches, and the fermented beer will be split between a beer surge tank for use in the cake mixer or the beerwell feeding the distillation column.

A set of six cellulosic fermentation vessels will be used to simultaneously saccharify and ferment the cellulose from the cake mixer. The cellulose will be saccharified by a proprietary enzyme, producing glucose sugars. These sugars will in turn be fermented with a proprietary microorganism to produce a dilute ethanol beer. The fermentations will occur in batches, and the fermented mash will be passed to a beerwell upon completion of each fermentation batch. The beer will then be transferred to a beer stripper that initiates the distillation process.

The heads (vapors) from the beer stripper will be passed to a stripper/rectifier for further distillation and then a molecular sieve system to remove remaining water (dehydration) from the product. The purified ethanol will then be denatured with gasoline, resulting in a product that contains approximately 95 to 98 percent ethanol by volume and 2 to 5 percent gasoline by volume. Note that for the purposes of this air permit application, a denatured ethanol product with 5 percent gasoline by volume (E95) has greater potential emissions than one with 2 percent gasoline by volume (E98), and therefore the finished product is referred to throughout the rest of this document as E95. Nevertheless, the facility is requesting the flexibility to produce denatured ethanol blends in the range between E95 and E98.

The proprietary enzyme and microorganism will be produced on site in the propagation system. Nutrients required to produce the enzyme and microorganism will be stored adjacent to the propagation system, and are described later in this section.

Emissions from the fermentation area and distillation area will be vented to an ethanol recovery absorber. The absorber is considered to be integral to the process as it returns a significant amount of volatilized ethanol back to the process. The absorber is vented to the aforementioned RTO. Emissions from the propagation area will be vented directly to the RTO.

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

2.2.5 Product and Denaturant Storage Tanks

The facility will include one storage tank for denatured ethanol product (referred to as E95 in the remaining portions of this permit application) and one gasoline (denaturant) storage tank. Each of these tanks will be designed with an internal floating roof. The facility will also include three ethanol product shift tanks. The shift tanks will be vented to the ethanol recovery absorber which in turn is vented to the RTO.

2.2.6 Product Loadout

E95 product will be loaded onto tank trucks at a rate of 600 gallons per minute. Vapors displaced from the trucks during product loading will be exhausted directly to the RTO. The trucks are assumed not to be in dedicated E95 service (i.e., some trucks will have returned from delivering gasoline and gasoline vapors will be displaced).

2.2.7 Miscellaneous Storage Tanks

The facility will include several other chemical storage tanks; however, all of these tanks will be insignificant sources of air emissions. These tanks include a number of storage tanks to store wet chemicals used in the process. Sulfuric acid (93% solution) will be used in hydrolysis. Magnesium hydroxide (61% solution) will be used to neutralize hydrolyzed material prior to fermentation. The propagation and fermentation nutrients will include corn syrup, phosphoric acid (85% solution), and aqueous ammonia (19% solution). A flocculant solution will be used in the stillage loadout area to recover additional solids. Caustic soda (50% solution) will be used for CIP. All of these tanks will be of a vertical fixed roof design.

2.2.8 Miscellaneous Storage Silos

The facility will include equipment and silos for the handling and storage of dry materials. These materials include nutrients for the propagation of the proprietary enzyme and microorganism, and materials associated with the biomass boilers. These materials will be stored in silos, each of which will be equipped with fabric filters (bin vent filters) to control emissions during material handling. The materials stored in these silos will be as follows:

- Powdered cellulose;

- Wheat Bran;
- Ammonium Sulfate;
- Potassium Phosphate;
- Urea;
- Ash;
- Sand;
- Limestone; and
- Hydrated Lime;

In addition to these silos, there will be two day bins located in the propagation area, one each for wheat bran and urea. These day bins will also be equipped with bin vent filters.

2.2.9 Stillage Loadout

Stillage cake will be removed from the bottom of the beer stripper, dewatered by centrifuges to remove some of the water fraction, and conveyed to the biomass boilers. The stillage cake will not be dried and will consist of lignin fibers, unhydrolyzed cellulose fibers, and other material with biomass fuel value. Stillage will be generated at a rate of 11 dry tons per hour with moisture content between 50 and 65 percent. Handling will be performed entirely within a closed system except for the conveyor system that sends the material to the biomass boiler. Due to the high moisture content of the stillage cake the conveyor system will not be covered. The centrifuges are not closed systems and will be vented to atmosphere.

2.2.10 Anaerobic Digestion

The facility will include an anaerobic digestion system to treat process wastewaters and recover energy from the thin stillage for use in the facility. The biogas produced by the anaerobic reactors will be burned in the biomass boiler and the facility will include a backup flare in the event that biogas cannot be combusted in the biomass boiler (either due to boiler shutdown or the production of surplus biogas). The biomass boiler and flare will each be designed with a maximum biogas heat input capacity of 100 MMBtu/hr. To meet BACT requirements, the anaerobic digestion system will be equipped with a hydrogen sulfide (H_2S) removal system for biogas burned in the flare (the biomass boiler is equipped with limestone injection and a scrubber for SO_2 control and as such H_2S removal will not be required for the boiler). Biosolids recovered from the centrifuge at a rate of approximately 2.75 dry tons per hour will also be burned in the biomass boiler.

2.2.11 Cooling Tower

An induced draft evaporative cooling tower will provide cooling of process water for the project. The tower will be of rectangular mechanical-draft design with four cells. Each cell will be equipped with its own fan and a high efficiency drift eliminator to minimize water drift losses. The flow rate will be approximately 50,000 gallons per minute. Total dissolved solids in the cooling water are expected to be approximately 2,750 mg/l.

2.2.12 Steam Production

Biomass Boiler. One biomass boiler with a heat input capacity of 270 MMBtu/hr, will be used to combust the stillage cake and biosolids. The boiler will be based on fluidized bed technology. The boiler will also be equipped to burn the biogas produced by anaerobic digestion, and will also be equipped to burn natural gas. The site will be supplied with natural gas by Florida Gas Transmission (FGT) via pipeline located along the north side of State Route 70.

The biomass boiler will produce base load steam at a variety of pressures for the ethanol production process. In addition, the steam will be used in a steam turbine generator to produce as much 7.6 megawatts (MW) of power for the project site. The electricity will not be sold to the grid and is solely intended for plant purposes.

Peaking Boiler. The facility will include a 95 MMBtu/hr peaking boiler to provide steam during peak process demand conditions and auxiliary steam if the biomass boiler is down. The boiler will be equipped to combust natural gas as the primary fuel.

2.2.13 Emergency Engines

Five emergency generators, each rated at 1,500 kW, will be installed to provide backup electrical power in the event of a power outage at the facility. A backup 850 hp diesel fire pump will also be installed to provide firewater during power outages. All of these units will fire ultra-low sulfur diesel (ULSD) and will be limited to 500 hours per year of operation. Each unit will be operated no more than 100 hours per year for testing and maintenance purposes. Each engine will be designed to meet USEPA's emission standards listed in 40 CFR Part 60 Subpart IIII for model year 2009 or later.

3.0 EMISSIONS INVENTORY

This section describes how emissions from the proposed Highlands Ethanol project were calculated based upon the results of the Best Available Control Technology (BACT) evaluation (see Section 5), emission factors obtained from USEPA's AP-42 *Compilation of Air Pollutant Emission Factors* (AP-42), USEPA emissions models such as TANKS, and ASPEN process modeling. Detailed emissions calculations are provided in Appendix B.

From a practical perspective relevant to the proposed project and its emissions, the list of regulated New Source Review (NSR) pollutants includes the six criteria pollutants for which National Ambient Air Quality Standards (NAAQS) have been established and those pollutants that are subject to the New Source Performance Standards (NSPS) promulgated pursuant to Section 111 of the federal Clean Air Act (CAA).

The six criteria pollutants are: sulfur dioxide (SO_2), particulate matter (PM), carbon monoxide (CO), ozone (O_3), nitrogen dioxide (NO_2), and lead (Pb). Volatile organic compounds (VOCs) and nitrogen oxides (NO_X) are included by virtue of being established as ozone precursors. For regulatory purposes, PM is further classified by particle size. $PM_{2.5}$ includes all particles with an aerodynamic diameter of less than 2.5 microns. PM_{10} includes all particles with an aerodynamic diameter of less than 10 microns. Total suspended particulate (TSP) includes particles of all sizes.

In addition to criteria pollutants, as of 2011 greenhouse gases (GHGs), expressed as carbon dioxide equivalents (CO_2e), are now evaluated to determine the applicability of Prevention of Significant Deterioration (PSD) permitting requirements. The PSD applicability of CO_2 emissions for biomass processes and combustion has been stayed by USEPA pending further evaluation. Therefore, CO_2 emissions are only considered for fossil fuel combustion. Other GHGs (e.g., methane and N_2O) are considered for both fossil fuels and biomass. The total non-biogenic GHG emissions are compared to the PSD applicability threshold. USEPA guidance encourages the calculation of both total GHG emissions and non-biogenic GHG emissions when inventorying emissions for permitting purposes.

The list of Hazardous Air Pollutants (HAPs) is defined in Rule 62-210.155, F.A.C. The list is identical to the federal list of HAPs pursuant to Section 112(b) of the Clean Air Act. From a practical perspective, many of the HAPs to be emitted from the proposed project are subsets of regulated NSR pollutants, particularly trace metals (PM) and trace organics (VOCs).

Annual emissions were calculated for comparison to regulatory thresholds, and short-term emissions (durations of 24 hours or less) were calculated to meet dispersion modeling requirements. Emissions of regulated NSR pollutants, GHGs, and HAPs were calculated.

Emissions from point sources and fugitive sources were quantified separately. Point sources are emission sources that are vented through a stack or vent. Fugitive sources are emission sources that have no specific emission point.

3.1 Point Sources

3.1.1 Regenerative Thermal Oxidizer (RTO)

The RTO will control VOC emissions from a number of emissions sources located at the facility, including Liquid/Solid Separation, Fermentation, Propagation, Product Day Storage, and Product Loadout. Pre-control emissions from each area were calculated separately and summed to determine potential emissions from the RTO. The captured VOC emissions will be destroyed with a BACT control efficiency of 99%. HAP hydrocarbons will likewise be destroyed with a control efficiency of 99%.

Emissions from the liquid/solid separation area will be vented directly to the RTO. ASPEN process modeling was employed to estimate VOC emissions from this process area prior to being vented to the RTO. The total VOC emission rate from the liquid/solid separation process was calculated to be 34 tons per year (tpy) before capture and control. The captured VOC emissions will be destroyed in the RTO with a BACT control efficiency of 99%. The total VOC emissions from the RTO, which also controls emissions from other process areas, are provided later in this section. Emissions of HAPs from this area were modeled to be negligible.

Emissions from the fermentation and distillation areas will be vented to the ethanol recovery absorber which in turn is vented to the RTO. ASPEN process modeling was employed to estimate VOC emissions from the fermentation and distillation process areas prior to being vented to the RTO (i.e., recovery by the ethanol absorber is accounted for). The total VOC emission rates from the fermentation and distillation areas were calculated to be 1560 tpy and 285 tpy, respectively after the absorber and before the RTO. The captured VOC emissions will be destroyed in the RTO with a BACT control efficiency of 99%. The total VOC emissions from the RTO, which also controls emissions from other process areas, are provided later in this section.

Acetaldehyde was modeled to be the most significant of the HAPs emitted from these process areas. The total acetaldehyde emission rates from the fermentation and distillation areas were calculated to be 703 tpy and 145 tpy, respectively after the absorber and before the RTO. The captured HAP emissions will be destroyed in the RTO with a BACT control efficiency of 99%. The total HAP emissions from the RTO, which also controls emissions from other process areas, are provided later in this section.

CO_2 emissions from the fermentation and distillation areas were calculated to be 146,000 tpy and 10,000 tpy, respectively. These GHG emissions are entirely biogenic in nature. Neither the ethanol absorber nor the RTO are capable of reducing these GHG emissions.

Emissions from the propagation area are expected to be negligible, but nevertheless are vented directly to the RTO. The total VOC and HAP emissions from the RTO are expected to be conservatively calculated and will account for the negligible contribution from the propagation area.

The total VOC emissions from the ethanol shift tanks were calculated to be 0.064 tpy after the absorber and before the RTO. The captured VOC emissions will be destroyed in the RTO with a BACT control efficiency of 99%. The total VOC emissions from the RTO, which also controls emissions from other process areas, are provided later in this section.

Product will be loaded onto tank trucks at a rate of 600 gallons per minute. Vapors displaced from the trucks will be exhausted directly to the RTO. The trucks are assumed to employ submerged fill techniques, but not be in dedicated E95 service (i.e., some trucks will have returned from delivering gasoline). The gasoline was assumed to have an RVP of 12. Displaced gasoline vapor emissions were calculated using USEPA's AP-42, Section 5.2 (USEPA, 1995a). Speciation of gasoline vapor emissions was derived for HAPs from Profile 2490 of USEPA's SPECIATE 3.2 database (USEPA, 2002a). The total VOC and HAP emission rates from product loadout were calculated to be 267 tpy and 18.6 tpy, respectively, before capture and control. The captured VOC and HAP emissions will be destroyed in the RTO with a BACT control efficiency of 99%. The total VOC and HAP emissions from the RTO, which also controls emissions from other process areas, are provided later in this section.

VOC, GHG, and HAP emissions from the various processes venting to the RTO are summarized in Table 3-1. The VOC and HAP emissions will be reduced by 99% per the BACT analysis presented in Section 5. The RTO is also equipped with a 3 MMBtu/hr natural gas burner which has combustion emissions associated with it. Detailed emissions calculations, including for the burner, are provided in Appendix B.

Table 3-1. Calculated Potential Emissions, RTO

Process Area	VOC (tpy)	Total CO_2e (tpy)	Non-Biogenic CO_2e (tpy)	Total HAP (tpy)
Liquid/Solid Separation	0.34	0.00	0.00	0.00
Fermentation	15.6	146,100	0.00	7.03
Distillation	2.85	10,000	0.00	1.45
Product Storage Shift Tanks	0.00064	0.00	0.00	0.00
Product Loadout	2.67	0.00	0.00	0.19
Total	21.4	156,100	0.00	8.7

3.1.2 Product and Denaturant Storage Tanks

VOC emissions from the ethanol shift tanks, the E95 storage tank, and denaturant storage tank were calculated using USEPA's TANKS 4.0.9d software (USEPA, 2001a). The ethanol shift tanks will be equipped with vertical fixed roofs and vented to the ethanol absorber. The E95 and denaturant storage tanks will be equipped with an internal floating roof. The gasoline was assumed to have a Reid Vapor Pressure (RVP) of 12. Speciation of gasoline vapor emissions was derived from Profile 2490 of USEPA's SPECIATE 3.2 database (USEPA, 2002a). This speciation was used to calculate HAP emissions from the E95 and gasoline storage tanks. A summary of the TANKS inputs and outputs are provided in Appendix B, as are the detailed TANKS outputs.

The total VOC emissions from the E95 and denaturant storage tanks were calculated to be 0.22 and 0.96 tpy, respectively. The total HAP emissions from these storage tanks were calculated to be 0.002 tpy and 0.067 tpy, respectively.

3.1.3 Miscellaneous Storage Silos

A number of bin vent filters will be used to control PM_{10} emissions from storage silos and their respective material handling operations. Per the BACT analysis presented in Section 5, all of these bin vent filters will be designed with outlet emissions of 0.005 grains per dry standard cubic foot (gr/dscf) of PM_{10}. Emissions from each of these storage silos were calculated from the respective exhaust flow rates and a conservative assumption that each will be in operation 8,760 hours per year. $PM_{2.5}$ emissions were conservatively set equal to the calculated PM_{10} emissions. The calculated potential PM_{10} emissions for the bin vent filters are summarized in Table 3-2.

3.1.4 Biogas Backup Flare

The biogas generated by anaerobic digestion will be combusted in the biomass boiler. The facility will include a flare for those occasions when the biomass boiler is not available. The biogas will be produced at a rate of 100 MMBtu/hr and will be conditioned to remove sulfur before combustion in the flare per the BACT analysis performed in Section 5. The emission calculations for the biomass boiler include the maximum potential emissions of the biogas for the purposes of comparison to permitting thresholds. Short-term emissions were calculated for the backup flare and are presented in Appendix B.

The backup flare will have a pilot that will combust natural gas. The pilot will have a capacity of 0.2 MMBtu/hr and was assumed to operate 8,760 hours per year. Combustion emissions of criteria pollutants were calculated using USEPA's AP-42, Section 13.5 (USEPA, 1995b). PM emissions were calculated by conservatively assuming a lightly smoking flare. The calculated emissions for the pilot are included in Table 3-3. Additionally, total CO_2e and non-biogenic CO_2e emissions from the flare were both calculated to be 94.0 tpy (pilot only), respectively.

Table 3-2. Calculated Potential Emissions, Storage Silos

Storage Silo	PM_{10} (tpy)	$PM_{2.5}$ (tpy)
Powdered Cellulose	0.47	0.47
Wheat Bran	0.47	0.47
Ammonium Sulfate	0.47	0.47
Potassium Phosphate	0.47	0.47
Bulk Urea	0.47	0.47
Discrete Wheat Bran Transfers	0.12	0.12
Discrete Urea Transfers	0.12	0.12
Sand	0.47	0.47
Limestone	0.47	0.47
Hydrated Lime	0.47	0.47
Ash	0.47	0.47
Total	4.5	4.5

Notes: Calculated emissions based on outlet emissions of 0.005 gr/dscf for fabric filter dust collectors, expected exhaust flow rates, and operations of 8,760 hrs/yr.

Table 3-3. Calculated Potential Emissions from Natural Gas Pilot, Biogas Backup Flare

Process	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)	NO_X (tpy)	CO (tpy)	VOC (tpy)
Biogas Backup Flare	0.002	0.002	0.0005	0.055	0.30	0.11

3.1.5 Cooling Tower

A mechanical draft cooling tower will provide cooling of process water for the project. The maximum design flow rate will be approximately 50,000 gallons per minute (GPM). Total dissolved solids in the cooling water are expected to be approximately 2,750 milligrams per liter (mg/l). Per the BACT analysis presented in Section 5, the cooling tower will be designed with a drift rate of 0.0005 percent or less to minimize PM_{10} emissions. The cooling tower will use a total of four cells.

Emissions were calculated using USEPA's AP-42, Section 13.4 (USEPA, 1995c). The total PM_{10} emissions from the cooling tower were calculated to be 1.5 tpy. The total $PM_{2.5}$ emissions were set equal to the PM_{10} emissions. Detailed emissions calculations are presented in Appendix B.

VOC emissions resulting from heat exchanger process fluid leaks into cooling water were calculated in accordance with the South Coast Air Quality Management District's (SCAQMD) "Guidelines for Calculating Emissions from Cooling Towers" (SCAQMD, 2006). Total VOC emissions from the cooling tower were calculated to be 9.2 tpy. Because Highlands Ethanol is proposing to perform weekly monitoring of VOCs in the cooling water, the emission factor that claims credit for VOC control was used. While volatile organic HAPs are expected to represent a negligible fraction of the VOCs leaking from this equipment, acetaldehyde emissions are conservatively assumed to comprise 5% of the VOC emissions. Detailed emissions calculations are presented in Appendix B. Equipment leaks will be minimized by implementation of a monitoring program that detects VOCs in cooling water.

3.1.6 Steam Production

Biomass Boiler. Combustion emissions were calculated based on the maximum heat input capacity of the boiler (270 MMBtu/hr) and the BACT analyses presented in Section 5. Emissions of HAPs were calculated based on USEPA's AP-42 for bagasse boilers (USEPA, 1996a). The boiler will be of fluidized bed design and will be equipped with a baghouse for PM emissions control, selective non-catalytic reduction (SNCR) for NO_X emissions control, and limestone injection into the fluidized bed and a dry scrubber for SO_2 emissions control. The boiler will burn primarily stillage cake at a maximum rate of 170 MMBtu/hr. Biosolids will be burned when insufficient stillage cake is available. The boiler will also be equipped to burn biogas at a maximum rate of 100 MMBtu/hr and natural gas at a rate of 250 MMBtu/hr. Supplemental biomass will not be combusted, in contrast to the existing permit, nor will ULSD or propane be combusted.

The calculated emissions for the biomass boiler are included in Table 3-4. Detailed emissions calculations are presented in Appendix B.

Table 3-4. Calculated Potential Emissions, Biomass Boiler

Process	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)	NO_X (tpy)	CO (tpy)	VOC (tpy)	HAP (tpy)
Biomass Boiler	11.8	11.8	71.0	94.6	118	5.91	6.6

Additionally, total CO_2e and non-biogenic CO_2e emissions from the biomass boiler were calculated to be 313,238 tpy and 128,864 tpy, respectively. The maximum potential non-biogenic GHG emissions assume that the full 250 MMBtu/hr of natural gas firing occurs year round.

Peaking Boiler. A peaking boiler with a maximum heat input capacity of 95 MMBtu/hr will be used to provide peaking steam demand for the process operations. The peaking boiler will use natural gas as the primary fuel. Combustion emissions were calculated based on the maximum heat input capacity of the boiler (95 MMBtu/hr) and the BACT analyses presented in Section 5. Emissions of HAPs were calculated based on USEPA's AP-42 for gas-fired boilers. ULSD or propane will not be combusted.

The calculated emissions for the peaking boiler are included in Table 3-5. Detailed emissions calculations are presented in Appendix B.

Table 3-5. Calculated Potential Emissions, Peaking Boiler

Process	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)	NO_X (tpy)	CO (tpy)	VOC (tpy)	HAP (tpy)
Peaking Boiler	1.7	1.7	2.3	14.6	15.4	0.6	0.8

Additionally, total CO_2e and non-biogenic CO_2e emissions from the peaking boiler were both calculated to be 49,100 tpy.

3.1.7 Emergency Engines

Five emergency generators, each rated at 1,500 kW, will be installed to provide backup electrical power in the event of a power outage at the facility. A backup 850 hp diesel fire pump will also be installed to provide firewater during power outages. All of these units will fire ULSD (propane will not be used) and will be limited to 500 hours per year of operation. Each unit will be operated no more than 100 hours per year for testing and maintenance purposes. Each engine will be designed to meet USEPA's emission standards listed in 40 CFR Part 60 Subpart IIII for model year 2009 or later. The maximum potential emissions from the emergency engines were calculated using the emission standards, the capacities of each unit, and the annual limit of 500 hours per year.

The calculated emissions for the emergency engines are included in Table 3-6. Detailed emissions calculations are presented in Appendix B.

Table 3-6. Calculated Potential Emissions, Emergency Engines

Process	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)	NO_X (tpy)	CO (tpy)	VOC (tpy)	HAP (tpy)
Emerg. Engine No. 1	0.2	0.2	0.006	4.8	2.9	0.53	0.014
Emerg. Engine No. 2	0.2	0.2	0.006	4.8	2.9	0.53	0.014
Emerg. Engine No. 3	0.2	0.2	0.006	4.8	2.9	0.53	0.014
Emerg. Engine No. 4	0.2	0.2	0.006	4.8	2.9	0.53	0.014
Emerg. Engine No. 5	0.2	0.2	0.006	4.8	2.9	0.53	0.014
Fire Pump	0.07	0.07	0.003	2.0	1.2	0.22	0.006
Total	0.9	0.9	0.03	25.8	15.7	2.9	0.08

Additionally, total CO_2e and non-biogenic CO_2e emissions from the emergency engines were both calculated to be 3,300 tpy.

3.2 Fugitive Sources

3.2.1 Feedstock Handling

Feedstock will be either delivered directly to the plant's feedstock hopper or to the feedstock storage pad area and subsequently conveyed to the feedstock hopper. The feedstock will be fresh material brought in from the adjacent farm and because of its high moisture content is not expected to produce fugitive PM emissions at the receiving areas. The feedstock will be washed and shredded and then fed through a series of three roller mills. The resulting bagasse will be stored in a silo. Surplus bagasse produced will be returned to the medium-term storage pad. The emissions from this process area are insignificant due to the high moisture content of the feedstock and the residual water from the washing step. The surplus bagasse will be handled using best management practices.

3.2.2 Hydrolysis

The hydrolysis system will operate under pressure and will not produce air emissions. The system is equipped with pressure safety valves (PSVs) which will be occasionally vented directly to the atmosphere. Because of the infrequent operation of the PSVs, the emissions from this process area are insignificant. At the outlet of the hydrolyzer, pressure is released and the resulting flash steam is condensed and sent to the anaerobic digester.

3.2.3 Stillage Loadout

Stillage cake will be removed from the bottom of the beer stripper, dewatered by centrifuges to remove some of the water fraction, and conveyed to the biomass boiler. The stillage cake will not be otherwise dried and will consist of lignin fibers, unhydrolyzed cellulose fibers, and other material with fuel value. Based on the consistency and high moisture content of the material, PM emissions are expected to be negligible. VOC emissions will occur from the evaporation of organics dissolved in the water fraction.

A VOC emission factor was identified for this process as follows. Three emission calculation procedures were identified for the permitting of the Pacific Ethanol Facility located in Madera, California (San Joaquin Valley Unified Air Pollution Control District, 2004) for distillers grain solids. The procedure that resulted in the greatest VOC emission rate was selected. The emission factor was then doubled for an additional margin of safety, resulting in a VOC emission factor of 0.1421 pounds per 1000 gallons of ethanol produced. Speciation of the VOC emissions was based on ASPEN modeling of the process. While the constituents were consistent with those identified in the Pacific Ethanol analysis, AMEC added an additional margin of safety by further tripling the emission factor. Based on the estimated speciation of

VOCs, volatile organic HAP emissions are expected to be negligible. Total fugitive VOC emissions from stillage loadout were calculated to be 8.4 tpy. Detailed emissions calculations are presented in Appendix B.

3.2.4 Fugitive VOC Equipment Leaks

Fugitive VOC emissions from equipment leaks were calculated in accordance with USEPA's "Protocol for Equipment Leak Emission Estimates" (USEPA, 1995d). Component counts were estimated from preliminary engineering drawings of the proposed facility. Total fugitive VOC emissions from equipment leaks were calculated to be 19.6 tpy. While volatile organic HAPs are expected to represent a negligible fraction of the VOCs leaking from this equipment, acetaldehyde emissions are conservatively assumed to comprise 5% of the VOC emissions. Detailed emissions calculations are presented in Appendix B. Fugitive equipment leaks will be minimized by implementation of a monthly leak detection and repair (LDAR) monitoring program in accordance with New Source Performance Standard (NSPS) 40 CFR Part 60, Subpart VVa.

3.2.5 Fugitive Roadway Emissions

Approximately 60 trucks per day will be used to deliver feedstock directly to the plant, and an additional 127 vehicles per day will drive on the plant roads. All roads on the commercial facility site will be paved.

Emissions were calculated using USEPA's AP-42, Sections 13.2.2 (USEPA, 2006) and 13.2.1 (USEPA, 2011a). Total fugitive PM_{10} and $PM_{2.5}$ emissions from roadways were calculated to be 0.4 tpy and 0.06 tpy, respectively. Detailed emissions calculations are presented in Appendix B.

3.3 **Summary of Calculated Potential Emissions**

A summary of calculated potential emissions for Highlands Ethanol is provided in Table 3-7. A more detailed summary of pollutant emissions is provided in Appendix B along with detailed emission calculations.

Table 3-7. Summary of Calculated Potential Emissions, Highlands Ethanol

Process	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)	NO_X (tpy)	CO (tpy)	VOC (tpy)	HAP (tpy)
RTO	0.03	0.03	0.07	0.46	0.49	21.44	8.70
Product/Denaturant Stg.	--	--	--	--	--	1.18	0.07
Misc. Storage Silos	4.5	4.5	--	--	--	--	--
Biogas Backup Flare	0.002	0.002	0.0005	0.055	0.30	0.11	--
Cooling Tower	1.5	1.5	--	--	--	9.2	0.5
Steam Production	13.5	13.5	73.3	109	134	6.50	7.3
Emergency Engines	0.90	0.90	0.033	25.8	15.7	2.87	0.08
Subtotal, Point Sources	**20.4**	**20.4**	**73.4**	**135.5**	**150.1**	**41.3**	**16.6**
Stillage Loadout	--	--	--	--	--	8.4	--
Equipment Leaks	--	--	--	--	--	19.6	0.98
Roadway Emissions	0.43	0.057	--	--	--	--	--
Subtotal, Fugitive Sources	**0.43**	**0.057**	**--**	**--**	**--**	**28.0**	**0.98**
Total	***20.8***	***20.4***	***73.4***	***135.5***	***150.1***	***69.3***	***17.6***

Additionally, total CO_2e and non-biogenic CO_2e emissions from the facility were calculated to be 523,308 tpy and 182,834 tpy, respectively.

4.0 APPLICABLE REQUIREMENTS

A summary of the federal and state air quality requirements and their applicability to emission units included in the proposed facility is provided in the following sections.

4.1 Federal Requirements

Brief explanations of the applicability or nonapplicability of federal requirements and other specific information are included for reference purposes.

4.1.1 Prevention of Significant Deterioration

PSD permitting requirements apply to criteria pollutants (SO_2, NO_2, PM_{10}, $PM_{2.5}$, CO, VOC, and Pb) and other "New Source Review Pollutants" (NSR Pollutants) such as H_2SO_4 and GHGs, but do not apply to HAPs. The PSD regulations specify that any major new stationary source within an air quality attainment area must undergo PSD review and obtain applicable federal and state preconstruction air permits prior to the commencement of construction.

Highlands County is designated as attainment or unclassified for all criteria pollutants. Florida has been delegated authority by USEPA to implement the federal Clean Air Act (CAA); therefore, the PSD program in Florida is administered by the FDEP under Rule 62-212.400, F.A.C. – *Stationary Sources – Preconstruction Review, Prevention of Significant Deterioration.* The PSD regulations apply to:

- Any source type listed in any of 28 designated industrial source categories having potential emissions of 100 tons per year or more of any pollutant regulated under the CAA;
- Any other source having potential emissions of 250 tons per year or more of any pollutant regulated under the CAA; and
- Any source having potential lead emissions greater than 5 tons per year.

PSD applicability thresholds are used to define whether or not a project is a major source. The thresholds are a function of source category and emissions, as noted above. Three of the "named source categories" may be relevant to the Highlands Ethanol project:

- chemical process plants,
- fossil-fuel boilers (or combinations thereof) totaling more than 250 MMBtu/hr heat input, and
- fossil fuel-fired steam electric plants of more than 250 MMBtu/hr heat input.

The PSD applicability threshold for the project would be potential emissions of 100 tons per year (tpy) if the project is defined as belonging to any of the three source categories above. The PSD applicability threshold is otherwise potential emissions of 250 tpy. The project would be considered a major source if the applicability thresholds are exceeded.

With respect to chemical process plants, in 2007 USEPA specifically delisted ethanol production facilities that produce ethanol by natural fermentation included in NAICS codes 325193 or 312140. At the time of the project's original air permit application in February 2009 and final permit issuance in June 2010, the FDEP had not adopted USEPA's delisting of these ethanol production facilities and therefore the project was issued a PSD permit. On March 28, 2012, FDEP finalized a rulemaking to adopt USEPA's delisting of ethanol by natural fermentation from the process chemical plant source category in Rule 62-212.400, F.A.C. Because the Highlands Ethanol project produces ethanol by natural fermentation, the project would not be subject to the 100 tpy PSD major source thresholds by virtue of being classified as a chemical process plant.

With ethanol production no longer a listed source category, the key factors in determining the PSD applicability threshold for the project are the *total* boiler heat input capacity of the facility *while firing fossil fuels*. Because PSD applicability is evaluated on a facility-wide basis, *total* boiler fossil fuel heat input capacity would need to be less than 250 MMBtu/hr to be subject to the 250 tpy applicability threshold.

The ability of the project to be permitted as a minor source hinges on the need for fossil fuel. Per USEPA's guidance and regulatory definitions, natural gas and oil are defined as fossil fuels while biomass is not. The biomass boiler will typically limit fossil fuel capacity to a fraction of the total capacity of the unit, with natural gas primarily used for boiler start-ups. However, Highlands Ethanol requires the ability to fire up to 250 MMBtu/hr of natural gas in the biomass boiler. In addition, the revised project will include a 95 MMBtu/hr peaking boiler firing natural gas, such that the total fossil fuel boiler heat input capacity for the project will be a maximum of 345 MMBtu/hr, greater than 250 MMBtu/hr. Therefore, the project would be subject to the 100 tpy PSD major source thresholds by virtue of having more than 250 MMBtu/hr of fossil fuel heat input capacity from boilers.

Because the biomass boiler powers a steam electric turbine, the unit is potentially classified as a steam electric plant. The total heat input capacity of fossil fuel for the biomass boiler and peaking boiler will total approximately 345 MMBtu/hr, which is greater than 250 MMBtu/hr. Therefore, the project would again be subject to the 100 tpy PSD major source thresholds by virtue of having more than 250 MMBtu/hr of fossil fuel heat input capacity from a steam electric plant.

In addition to criteria pollutants, as of 2011 GHGs, expressed as CO_2e, are now evaluated under PSD for the combustion of fossil fuel. The PSD applicability threshold for GHGs for new sources is 100,000 tpy of CO_2e assuming that emissions of each of the other NSR pollutants are less than the 100 tpy/250 tpy thresholds. For modifications to PSD sources, the major modification threshold for GHGs is 75,000 tpy of CO_2e. This includes GHGs from all fossil fuels fired at the plant including the emergency engines and the fire pump. The PSD applicability of CO_2 emissions for biomass combustion has been stayed by USEPA pending further evaluation. Therefore, CO_2 emissions are only considered for fossil fuel combustion. Other GHGs (e.g., methane and N_2O) are considered for both fossil fuels and biomass. The total non-biogenic GHG emissions are compared to the PSD applicability threshold. Based on the fossil fuel capacity of the boilers and the currently permitted emergency equipment, annual potential emissions of non-biogenic GHGs would be approximately 182,800 tons CO_2e. Because the project will emit more than the 75,000 tpy significant emission rate (SER) and the 100,000 tpy major source threshold for non-biogenic GHGs, the project is subject to PSD and is including a BACT analysis for GHGs.

Potential emissions are defined as the emission of any pollutant at maximum design capacity (or less than maximum design capacity if specified as a permit condition) including the control efficiency of air pollution control equipment. Based on the revised project calculated potential emissions, the project will exceed the PSD applicability and significant emission rate thresholds for criteria pollutants. A summary of potential emissions for the project are provided in Table 4-1.

Table 4-1 – Potential Emissions Compared to PSD Applicability Thresholds

Pollutant	Potential Annual Emissions (tpy)	Major Source Threshold (tpy)	Significant Emissions Threshold (tpy)	PSD/NSR Applies?
NO_X	135.5	100	40	yes
CO	150.1	100	100	yes
VOC	69.3	100	40	yes
PM_{10}	20.8	100	15	yes
$PM_{2.5}$	20.4	100	10	yes
SO_2	73.4	100	40	yes
Pb	0.06	5	N/A	yes
GHGs	182,800	100,000	75,000	yes

4.1.2 New Source Performance Standards

New Source Performance Standards (NSPS) apply to specific source categories. These standards are codified in 40 CFR 60, Standards of Performance for New Stationary Sources and adopted by reference in Rule 62-204.800(8), F.A.C. The following NSPS standards will apply to the proposed facility:

40 CFR 60 Subpart A - General Provisions

The general provisions contained in Subpart A will apply to the emission sources that are subject to an NSPS standard [40 CFR §60.1(a)]. These general provisions include notification and recordkeeping requirements (described in 40 CFR §60.7), testing requirements (described in 40 CFR §60.8), and monitoring requirements (described in 40 CFR §60.13).

The general provisions also include requirements for flares (40 CFR §60.18). Flares must be operated with a pilot flame present at all times and the presence of the flare pilot must be monitored using a thermocouple or equivalent device such as an infrared sensor.

Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

This subpart applies to each steam generating unit capable of combusting more than 100 MMBtu/hr heat input of fuels, which is constructed, modified, or reconstructed after June 19, 1984. The provisions of 40 CFR 60 Subpart Db will apply to the biomass boiler because the boiler's maximum firing rate will be 270 MMBtu/hr and will be constructed after June 19, 1984.

Subpart Db requirements limit emissions for the biomass boiler as follows:

- SO_2 emissions are limited to 0.20 pounds per million British thermal units (lb/MMBtu) heat input or 8 percent (0.08) of the potential SO_2 emission rate (92 percent reduction) and 1.2 lb/MMBtu heat input [40 CFR 60.42b(k)(1)] determined on a 30-day rolling average basis [40 CFR 60.42b(e)];
- Filterable PM emissions are limited to 0.030 lb/MMBtu heat input when burning coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels [40 CFR 60.43b(h)(1)]; or
- Opacity is limited to 20 percent (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity [40 CFR 60.43b(f)];
- NO_X emissions (expressed as NO_2) are limited to 0.10 to 0.20 lb/MMBtu for NO_X heat input when firing low and high heat release rate natural gas [40 CFR 60.44b(a)] and 0.30 lb/MMBtu when combusting biomass [40 CFR 60.44b(d)]
- Where more than 10 percent of total annual output is electrical or mechanical, the unit may comply with an optional NO_X emission limit (expressed as NO_2) of 2.1 lb/MWh gross energy output on a 30-day rolling average basis [40 CFR 60.44b(l)(3)], and units complying with this output-based limit must demonstrate compliance according to the procedures of §60.48Da(i), and must monitor emissions according to §60.49Da(c), (k), through (n).

The proposed emission rates for the biomass boiler will comply with all of the applicable Subpart Db emission limits.

The SO_2 emission standards under §60.42b will apply at all times including periods of startup, shutdown, or malfunction [40 CFR 60.45b(a)]. The PM emission standards and opacity limits under §60.43b will apply at all times except during periods of startup, shutdown, or malfunction

[40 CFR 60.46b(a)]. The NO_X emission standards under §60.44b will apply at all times including periods of startup, shutdown, or malfunction [40 CFR 60.46b(a)]. Compliance and performance test methods and procedures will be required as described in §§60.45b and 60.46b.

Continuous Emission Monitoring Systems (CEMS) will be required to be installed, calibrated, maintained, and operated for SO_2 [40 CFR 60.47b], opacity [40 CFR 60.48b(a)], NO_X [40 CFR 60.48b(b)], and either O_2 or CO_2 content in flue gases [40 CFR 60.47b and 40 CFR 60.48b(b)]. CEMS operation and data records will be required during all operating periods for the affected facility, including periods of startup, shutdown, malfunction, or emergency conditions, and except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments. Reporting and recordkeeping requirements are summarized in §60.49b.

Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

This subpart applies to each steam generating unit capable of combusting more than 10 but less than 100 MMBtu/hr heat input of fuels, which is constructed, modified, or reconstructed after June 19, 1984. The provisions of 40 CFR 60 Subpart Dc will apply to the natural gas fired peaking boiler because the boiler's maximum firing rate will be 95 MMBtu/hr and will be constructed after June 1, 1989. NSPS Subpart Dc does not require any emissions limitations or CEMS for natural gas fired units. However, the peaking boiler will be subject to the notification, recordkeeping, and reporting requirements.

40 CFR 60 Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

Subpart Kb applies to each storage vessel with a capacity greater than or equal to 75 cubic meters (m^3) [19,813 gallons] that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984 [40 CFR §60.110b(a)]. This subpart does not apply to [40 CFR §60.110b(b)]:

- Storage vessels with a capacity greater than or equal to 151 m^3 [39,890 gallons] storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) [0.51 pounds per square inch absolute or psia]; and
- Storage vessels with a capacity greater than or equal to 75 m^3 [19,813 gallons] but less than 151 m^3 [39,890 gallons] storing a liquid with a maximum true vapor pressure less than 15.0 kPa [2.18 psia].

Subpart Kb applies to the three (3) Product Shift Tanks and the ethanol (E95-E98) storage tank because the tank capacities are greater than 19,813 gallons. Storage vessels with a design capacity greater than or equal to 151 m^3 (39,890 gallons) containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa (0.75 psia) but less than 76.6 kPa (11.1 psia) is required to equip each storage vessel with one of the following:

- A fixed roof in combination with an internal floating roof meeting the specifications of [40 CFR §60.110b(a)(1)]; or
- An external floating roof, where an external floating roof means a pontoon-type or double-deck type cover that rests on the liquid surface in a vessel with no fixed roof. Each external floating roof must meet the specifications of [40 CFR §60.110b(a)(2)].

The product shift tanks will be 38,500 gallons each (less than 39,890 gallons) and will not require an internal floating roof. These tanks will meet subpart Kb using submerged fill pipes and a fixed roof with emissions exhausting to the ethanol absorber and RTO.

Subpart Kb also applies to the 472,000 gallon E95-E98 product tank. The product storage tank will be equipped with an internal floating roof as prescribed in 40 CFR §60.112b(a)(1). During truck filling operations, displaced vapors from the trucks will be exhausted to the RTO. This tank will also be subject to the monitoring, recordkeeping, and reporting requirements contained in 40 CFR §60.113b and §60.116b. The 13,000 gallon Denaturant Storage tank is not subject to Subpart Kb because the tank volume is less than 19,813 gallons [40 CFR §60.110b(b)], although it will be equipped with a floating roof to meet BACT requirements.

Subpart Kb will not apply to the following tanks because VOLs are not stored in the tank: Sulfuric Acid Storage Tank; Aqueous Ammonia Storage Tank; Phosphoric Acid Storage Tank, Magnesium Hydroxide Storage Tank, FO Inoculum Storage Tanks, Enzyme Storage Tanks, and Caustic Storage Tank. Subpart Kb will not apply to the Corn Syrup Storage Tank, or Flocculant Solution Storage Tank because the vapor pressures of the materials are less than 0.51 psia. All of these storage tanks are insignificant emission units.

For reference, 40 CFR 60 Subpart Kb does not apply to storage vessels used to store beverage alcohol [40 CFR §60.110b(d)(7)]. Because the proposed facility will be manufacturing fuel alcohol, this exemption will not apply.

40 CFR 60 Subpart VVa - Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry

Subpart VVa applies to an affected facility in the synthetic organic chemicals manufacturing industry (SOCMI) [40 CFR §60.480a(a)] that commences construction or modification after November 7, 2006 [40 CFR §60.480a(b)]. Further, this subpart applies to equipment components (i.e., each pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector) in VOC service, which means that the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight [40 CFR §60.481a]. Any affected facility that has a design capacity to produce less than 1,000 Mg/yr (1,102 ton/yr) is exempt from §60.482a [40 CFR §60.480a(d)(2)]. By definition, the list of chemicals produced by affected facilities, as intermediates or final products, by process units covered under this subpart includes: CAS No. 64-17-5, Ethanol [40 CFR §60.489].

The equipment components proposed for the facility in VOC service will be subject to the standards, including controls, monitoring, repair, recordkeeping, and reporting requirements of 40 CFR 60 Subpart VVa because the facility will have the design capacity to produce 127,725 tons per year (>1,102 tons per year exemption threshold) of ethanol. Emissions from these components are identified as Fugitive Equipment Leaks.

For reference, 40 CFR 60 Subpart VVa does not apply to beverage alcohol facilities. This subpart states that "Any affected facility that produces beverage alcohol is exempt from §60.482a" [40 CFR §60.480a(d)(4)]. However, if an owner or operator applies for one or more of the exemptions in this paragraph, then the owner or operator shall maintain records as required in §60.486a(i) [40 CFR §60.480a(d)(1)]. Because the proposed facility will be manufacturing fuel alcohol, this exemption will not apply.

40 CFR 60 Subpart NNN - Standards of Performance for Volatile Organic Compound (VOC) Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations

Subpart NNN applies to an affected SOCMI facility [40 CFR §60.660(a)] that commences construction, modification, or reconstruction after December 30, 1983 [40 CFR §60.660(b)]. The affected facility is any of the following [40 CFR §60.660(b)(1), (2), (3)]:

- Each distillation unit not discharging its vent stream into a recovery system;
- Each combination of a distillation unit and the recovery system into which its vent stream is discharged; or
- Each combination of two or more distillation units and the common recovery system into which their vent streams are discharged.

Any affected facility that has the design capacity to produce less than 1,000 megagrams (Mg) per year (1,102 tons per year) is exempt from all provisions of this subpart except for the recordkeeping and reporting requirements in paragraphs (j), (l)(6), and (n) of §60.665 [40 CFR §60.660(c)(5)]. Each affected facility operated with a vent stream flow rate less than 0.008 standard cubic meters per minute (scm/min) [0.28 standard cubic feet per minute (scfm)] is exempt from all provisions of this subpart except for the test method, procedure, recordkeeping, and reporting requirements in §60.664(g) and paragraphs (i), (l)(5), and (o) of §60.665 [40 CFR §60.660(c)(6)]. By definition, the list of chemicals produced by process units as a product, by-product, or intermediate covered under this subpart includes: Ethanol, CAS No. 64-17-5 [40 CFR §60.667].

Emission sources at the facility that are potentially subject to Subpart NNN include:

- Distillation, which includes emissions from various vent sources including the distillation columns and associated molecular sieve system.

For reference, 40 CFR 60 Subpart NNN does not apply to beverage alcohol facilities. This subpart states that "Any distillation unit operating as part of a process unit which produces coal tar or beverage alcohols, or which uses, contains, and produces no VOC is not an affected facility" [40 CFR §60.660(c)(1)]. Because the proposed facility will be manufacturing fuel alcohol, this exemption will not apply.

However, according to a USEPA Federal Register notice (72 FR 41117) and several letters issued by USEPA Region 5 (see USEPA Applicability Determination Index Control Numbers 0100076 and 0100083 and USEPA correspondence dated October 20, 2000), ethanol manufacturing facilities are exempt from the requirements of NSPS Subpart NNN because the NSPS background information document (USEPA, 1983) states that "The scope of the distillation NSPS does not include polymers, coal tar distillation products, chemicals extracted from natural sources, or chemicals totally produced by biological synthesis." The ethanol produced by the proposed facility will be created by fermentation (biological synthesis), which is excluded from the scope of Subpart NNN. Highlands Ethanol previously requested that USEPA Region 4 issue a site-specific exemption from the requirements in 40 CFR 60 Subpart NNN, which USEPA subsequently granted. A copy of the USEPA's letter is included in Appendix D.

40 CFR 60 Subpart RRR - Standards of Performance for Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes

Subpart RRR applies to an affected SOCMI facility [40 CFR §60.700(a)] that commences construction, modification, or reconstruction after June 29, 1990 [40 CFR §60.700(b)]. The affected facility is any of the following [40 CFR §60.700(b)(1), (2), (3)]:

- Each reactor process not discharging its vent stream into a recovery system;
- Each combination of a reactor process and the recovery system into which its vent stream is discharged; or
- Each combination of two or more reactor processes and the common recovery system into which their vent streams are discharged.

Any affected facility that has the design capacity to produce less than 1,000 Mg/yr (1,102 ton/yr) is exempt from all provisions of this subpart except for the recordkeeping and reporting requirements in paragraphs (i), (l)(5), and (n) of §60.705 [40 CFR §60.700(c)(3)]. Each affected facility operated with a vent stream flow rate less than 0.011 scm/min [0.39 scfm] is exempt from all provisions of this subpart except for the test method, procedure, recordkeeping, and reporting requirements in §60.704(g) and paragraphs (h), (l)(4), and (o) of §60.665 [40 CFR §60.700(c)(4)]. If the vent stream from an affected facility is routed to a distillation unit subject to Subpart NNN and has no other releases to the air except for a pressure relief valve, the facility is exempt from all provisions of this subpart except for §60.705(r) [40 CFR §60.700(c)(5)]. By definition, the list of chemicals produced by process units as a product, by-product, or intermediate covered under this subpart includes: Ethanol, CAS No. 64-17-5 [40 CFR §60.707].

Emission sources at the facility that are potentially subject to Subpart RRR include:

- Fermentation, which includes emissions from various vent sources including the fermentation vessels.

For reference, 40 CFR 60 Subpart RRR does not apply to beverage alcohol facilities. This subpart states that "Any reactor process operating as part of a process unit which produces beverage alcohols, or which uses, contains, and produces no VOC is not an affected facility" [40 CFR §60.700(c)(6)]. Because the proposed facility will be manufacturing fuel alcohol, this exemption will not apply.

However, according to a USEPA Federal Register notice (72 FR 41117) and several letters issued by USEPA Region 5 (see USEPA Applicability Determination Index Control Numbers 0100076 and 0100083 and USEPA correspondence dated October 20, 2000), ethanol manufacturing facilities are exempt from the requirements of NSPS Subpart RRR because the NSPS background information document (USEPA, 1990a) states that "... a total of 173 chemicals produced ... are included in the scope of reactor processes. The list of 173 chemicals ... does not include polymers or chemicals produced exclusively by biological synthesis." The ethanol produced by the proposed facility will be created by fermentation (biological synthesis), which is excluded from the scope of Subpart RRR. Highlands Ethanol previously requested that USEPA Region 4 issue a site-specific exemption from the requirements in 40 CFR 60 Subpart RRR, which USEPA subsequently granted. A copy of USEPA's letter is included in Appendix D.

Subpart IIII: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

This subpart applies to owners and operators of stationary compression ignition (CI) internal combustion engines (ICE) that commence construction after July 11, 2005, and where the stationary CI ICE are manufactured after April 1, 2006, for non-fire pump engines or manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006 [40 CFR 60.4200(a)(2)(i) and (ii)]. The rule requires manufacturers of these engines to meet emission standards based on engine size, model year, and end use. The rule requires owners and operators to configure, operate, and maintain the engines according to specifications and instructions provided by the engine manufacturer. The provisions of 40 CFR 60 Subpart IIII will apply to the five emergency generators and the diesel fire pump engine because the engines will be manufactured after July 1, 2006. The project must also comply with recordkeeping and reporting requirements.

The fire pump proposed for the project will have a displacement of less than 30 liters per cylinder and maximum engine power in the range of 850 horsepower. Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder are required to comply with the emission standards in Table 4 as specified §60.4202(d). For engine power greater than 750 horsepower, the model year 2008 (and later) applicable emission standard for non-methane hydrocarbons (NMHC) plus NO_X is 6.4 grams per kilowatt-hour (g/kW-hr) (4.8 grams per brake horsepower-hour [g/hp-hr]) and for PM is 0.20 g/kW-hr (0.15 g/hp-hr) [40 CFR 60.4205(c)]. These emission standards are required to be met for the entire life of the engine [40 CFR 60.4206]. The project's fire pump will be manufacturer certified to meet the 2008 standards.

§60.4202(d) of Subpart IIII requires that the proposed emergency generators for the project meets the non-road CI engine standards promulgated in 40 CFR 89. The engine manufacturer will be required to manufacture and certify that their engines are compliant with this rule. Beginning on October 1, 2010, owners and operators of stationary CI ICE subject to this subpart are required to use diesel fuel that meets the requirements of 40 CFR 80.510(b) for a maximum sulfur content of 15 parts per million weight (ppmw) (0.0015 percent) for non-road diesel fuel [40 CFR 60.4207(a) and (b)].

For the purposes of NSPS Subpart IIII, the date that construction commences is the date that the engine is ordered. Highlands Ethanol will install a diesel fire pump and emergency generators with certified engines that meet the requirements within this subpart. In addition, Highlands Ethanol will use diesel fuel with a sulfur content of 0.0015 percent (15 ppmw) to meet the requirements in 40 CFR 80.

Monitoring requirements include the following:

- Owners or operators of emergency stationary CI ICE are required to install a non-resettable hour meter prior to the startup of an engine [40 CFR 60.4209(a)]; and
- Owners or operators of stationary CI ICE with a diesel particulate filter are required to install a backpressure monitor that indicates when the high backpressure limit of the engine is approached [40 CFR 60.4209(b)].

Compliance requirements for owners or operators are described in 40 CFR 60.4211. Emergency stationary CI ICE may be operated for recommended maintenance checks and readiness testing, which is limited to 100 hours per year. There is no time limit on the use of emergency stationary CI ICE in emergency situations [40 CFR 60.4211(e)].

Non-Applicable NSPS Regulations

For reference purposes, the following NSPS standards will not apply to the proposed facility:

40 CFR 60 Subpart CCCC - Standards of Performance for Commercial and Industrial Solid Waste Incineration (CISWI) Units

Subpart CCCC applies to new combustion sources that fire solid waste. Subpart CCCC defines solid waste as that term is defined in 40 CFR 241. On March 21, 2011, EPA issued a final rule to revise 40 CFR 241 for the *Identification of Non-Hazardous Secondary Materials That Are Solid Waste*. Materials that satisfy the definition of non-hazardous solid waste under 40 CFR 241 are exempt from the provisions of Subpart CCCC.

The stillage cake to be combusted in the boiler consists of lignin fibers, unhydrolyzed cellulose fibers, and other material with biomass fuel value. 40 CFR 241.2 exempts *alternative fuels* from the definition of solid waste and includes *clean cellulosic biomass* as an alternative fuel. *Clean cellulosic biomass* is defined as those residuals that are akin to traditional cellulosic biomass such as forest derived biomass, corn stover and other biomass crops used specifically for energy production (e.g., energy cane, other fast growing grasses), bagasse and other crop residues (e.g., peanut shells). Clean biomass is biomass that does not contain contaminants at concentrations not normally associated with virgin biomass materials. The stillage cake meets the definition of clean cellulosic biomass and is therefore exempt from Subpart CCCC.

The biosolids produced by the anaerobic digester are a secondary material as defined under 40 CFR 241. The March 2011 revisions to 40 CFR 241 provide exceptions to certain secondary materials to exempt them as a solid waste. Included within these exceptions are nonhazardous secondary materials that remain within the control of the generator and are used as a fuel in accordance with 40 CFR 241.3(b)(1). The following criteria must be met to meet this exception:

1. The material must be generated and burned at the same facility or a facility under the same control as the generating facility; and
2. The material must meet the legitimacy criteria under 40 CFR 241.3(d);

The biosolids will be generated and burned onsite and therefore the first criterion above is satisfied. The legitimacy criteria under 40 CFR 241.3(d) include the following:

i) The material must be managed as a valuable commodity based upon the following factors:

A. *The storage of the non-hazardous secondary material prior to use must not exceed reasonable time frames;*

B. *Where there is an analogous fuel, the non-hazardous secondary material must be managed in a manner consistent with the analogous fuel or otherwise be adequately contained to prevent releases to the environment;*

C. *If there is no analogous fuel, the non-hazardous secondary material must be adequately contained so as to prevent releases to the environment.*

ii) The non-hazardous secondary material must have a meaningful heating value and be used as a fuel in a combustion unit that recovers energy.

iii) The non-hazardous secondary material must contain contaminants at levels comparable in concentration to or lower than those in traditional fuels which the combustion unit is designed to burn. Such comparison is to be based on a direct comparison of the contaminant levels in the nonhazardous secondary material to the traditional fuel itself.

The biosolids at the facility will be treated as a valuable commodity in two respects: first as a soil amendment to be applied to the farm that grows the ethanol plant's feedstock (the facility is already permitted by FDEP to use the biosolids in this manner) and second as a fuel with recoverable heat content. All biosolids will be transferred out of the digester to a settling tank and then conveyed to a centrifuge for dewatering via a sludge pump and enclosed piping system. From there, the biosolids will be either delivered to trucks or conveyed from the centrifuge to the boiler via the same conveyor used to deliver stillage cake from its centrifuges to the boiler. This system is designed to operate continuously. During periods when the boiler is shut down, the biosolids will remain in the digester and settling tank. Accordingly, there will be no planned "storage" of biosolids for the project other than in truck trailers for delivery to the farm. The system will be adequately contained to prevent releases and the biosolids will be used in a reasonable timeframe consistent with a valuable commodity, and therefore the first criterion is met.

In the preamble to the March 2011 final rule, EPA established a general guideline value of 5,000 Btu/lb as a meaningful heat content. The design heat content of the biosolids from the centrifuge is approximately 7,700 Btu/lb on a dry basis, which is well above the guideline value and therefore, the biosolids have a meaningful heat content and therefore the second criterion is met.

In the preamble to the final rule, EPA compared the concentration of trace metals in municipal wastewater treatment plant sludge to that of coal. Using that comparison as a guide, the trace metals composition of the biosolids is compared to that of clean wood and coal in Table 4-2. The coal composition shown is taken from the preamble to the March 2011 rules (76 FR 15515).

The wood composition shown is taken from Table 7-37 in NYSERDA's report, *Wood Products in the Waste Stream: Characterization and Combustion Emissions* (NYSERDA, 1992).

Table 4-2 – Comparison of Biosolids to Traditional Solid Fuels

Pollutant	Biosolids (ppmw)	Clean Wood (ppmw)	Coal (ppmw)
Arsenic	0.51	0.26	10
Cadmium	0.034	0.05	0.5
Chromium	0.22	2.50	20
Lead	0.43	4.33	40
Mercury	0.0046	0.13	0.1
Nickel	0.14	4.25	20
Selenium	0.34	--	1

As summarized in the above table, the concentration of pollutants in the biosolids is well below that in coal and generally considerably better than that in clean wood. Emissions of criteria pollutants from the firing of the biosolids are expected to be consistent with those for combusting stillage cake and will comply with the BACT limits proposed for the project. Therefore, biosolids were determined to contain contaminants at levels lower than those in traditional fuels and therefore the third criterion is met.

Therefore, the biosolids satisfy the legitimacy criteria under 40 CFR 240.3(d) and can be considered a nonhazardous secondary material in accordance with 40 CFR 241.3(b)(1) that is exempt from the requirements of NSPS Subpart CCCC (CISWI).

In accordance with 40 CFR 241.3(a), a petition to and determination from the EPA is not required for the stillage and biosolids in order to take the above exemptions. The stillage is categorically exempt from the CISWI rule and biosolids are exempt per 40 CFR 241.3(b), which is exempt from the petition process.

40 CFR 60 Subpart K - Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978

40 CFR 60 Subpart Ka - Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984

The facility storage tanks will not be subject to the requirements of 40 CFR 60 Subpart K and Subpart Ka because construction commenced later than the dates specified by these rules.

40 CFR 60 Subpart DD - Standards of Performance for Grain Elevators

The facility will not store any feedstock on-site that is subject to Subpart DD. Furthermore, no process unit at the facility meets the definition of a grain terminal elevator or a grain storage elevator [40 CFR §60.301]. As defined in the regulation: *Grain terminal elevator* means any grain elevator, which has a permanent storage capacity of more than 88,100 m^3 (ca. 2.5 million U.S. bushels), except those located at animal food manufacturers, pet food manufacturers, cereal manufacturers, breweries, and livestock feedlots; and *Grain storage elevator* means any grain elevator located at any wheat flour mill, wet corn mill, dry corn mill (human consumption), rice mill, or soybean oil extraction plant which has a permanent grain storage capacity of 35,200 m^3 (ca. 1 million bushels) [40 CFR §60.301(a), (c), and (f)].

40 CFR 60 Subpart VV - Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry

The proposed facility will not be subject to the requirements of 40 CFR 60 Subpart VV because construction will commence after November 7, 2006.

40 CFR 60 Subpart XX - Standards of Performance for Bulk Gasoline Terminals

The Denaturant Storage Tank will not be subject to the requirements of 40 CFR 60 Subpart XX because the facility does not meet the definition of a bulk gasoline terminal [40 CFR §60.500(a)]. As defined in the regulation, *Bulk gasoline terminal* means any gasoline facility, which receives gasoline by pipeline, ship or barge, and has a gasoline throughput greater than 75,700 liters per day (20,000 gallons per day) [40 CFR §60.501]. Highlands Ethanol will receive on average 5,700 gallons per day of denaturant, which is less than the applicability threshold of Subpart XX.

40 CFR 60 Subpart III - Standards of Performance for Volatile Organic Compound (VOC) Emissions from the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes

Process equipment at the proposed facility will not be subject to the requirements in 40 CFR 60 Subpart III because the facility does not meet the definition of an air oxidation unit process [40 CFR §60.610(a)]. As defined in the regulations, *Air oxidation unit process* means a unit process, including ammoxidation and oxychlorination unit process, that uses air, or a combination of air and oxygen, as an oxygen source in combination with one or more organic reactants to produce one or more organic compounds [40 CFR §60.611].

4.1.3 National Emission Standards for Hazardous Air Pollutants and Maximum Achievable Control Technology

National Emission Standards for Hazardous Air Pollutants (NESHAPs) apply to specific pollutants, as codified in 40 CFR 61, and to specific source categories, as codified in 40 CFR 63, NESHAPs for Source Categories. None of the regulations in 40 CFR 61 apply to the proposed facility. The regulations in 40 CFR 63 contain standards for maximum achievable control technology (MACT) that apply mainly to major sources of HAP emissions – defined as a stationary source that has the potential to emit 10 tpy of any single HAP or 25 tpy of any combination of HAPs. However, in a few instances, MACT standards have been promulgated for HAP area sources (e.g., engines and boilers). NESHAPs corresponding to 40 CFR 61 have been adopted by reference in Rule 62-204.800(10), F.A.C. NESHAPs corresponding to 40 CFR 63 have been adopted by reference in Rule 62-204.800(11), F.A.C. Because the facility will not be a major source of HAP emissions (i.e., emissions from the proposed facility do not exceed 10 tpy for any individual HAP and 25 tpy for all HAPs collectively) most of the MACT standards will not apply. However, 40 CFR 63 Subpart ZZZZ - *National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines* and Subpart JJJJJJ - *National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers – Area Sources* will apply to the Project.

40 CFR 63 Subpart A – General Provisions

The general provisions contained in Subpart A apply to certain emission sources that are subject to a NESHAP standard [40 CFR §63.1(b)]. The general provisions of 40 CFR Part 63 Subpart A apply to the owner or operator of any stationary source which contains an affected facility that is subject to any applicable subpart contained within 40 CFR Part 63. Compliance with standards and maintenance requirements, including startup, shutdown, and malfunction plans, are described in §63.6. 40 CFR 63.7 specifies performance testing requirements, and 40 CFR 63.8 specifies required monitoring. Requirements for notifications are described in §63.9, and recordkeeping and reporting requirements are described in §63.10. 40 CFR 63.11 contains control device requirements. The proposed biomass boiler is subject to area source MACT standards and therefore must comply with Subpart A. Likewise, the emergency engines are subject to area source MACT standards and therefore must comply with Subpart A.

40 CFR 63 Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

EPA promulgated National Emissions Standards for Hazardous Air Pollutants (NESHAPS) for Stationary Reciprocating Internal Combustion Engines (RICE) in 40 CFR 63 Subpart ZZZZ in several phases. The 2004 standard regulated new and modified RICE located at major HAP sources. Revisions to Subpart ZZZZ in December 2007 included new RICE located at HAP "area sources." In March 2010, EPA promulgated revisions to Subpart ZZZZ to address existing compression ignition (CI) RICE located at HAP area sources or that are located at major HAP sources and have a site rating of less than 500 horsepower. And lastly, on August 10, 2010, EPA issued a final rule that regulates HAPs from existing spark ignition RICE.

The potential HAP emissions from the project will be less than major source HAP thresholds and therefore, the project is an area source of HAPs subject to NESHAP Subpart ZZZZ. As specified in this regulation, compliance with NSPS Subparts IIII also satisfies the requirements of Subpart ZZZZ. The project will comply with all applicable requirements of NSPS Subpart IIII for the emergency engines and fire pump and will thereby also comply with NESHAP Subpart ZZZZ. No other requirements under Part 63 apply to the engines.

40 CFR 63 Subpart JJJJJJ - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers – Area Sources

On March 21, 2011, USEPA published MACT standards for area source boilers. On March 21, 2011, USEPA also promulgated a reconsideration of certain aspects of the implementation of the area source boiler rule. On December 23, 2011, USEPA published proposed changes to the area source boiler MACT rule. These changes to the regulations do not impact the applicability or emission limits of the biomass boiler.

If the facility remains a minor source for HAPs, the biomass boiler will be subject to MACT standards under Subpart JJJJJJ. Under Subpart JJJJJJ, a new boiler would be subject to emission limits for filterable particulate matter (0.03 lb/MMBtu for a fluidized bed boiler). Monitoring requirements include either a fabric filter leak detection system or compliance with an opacity limit of 10 percent or less (continuous opacity monitor system - COMS). In addition, the area source MACT requires an initial stack test for particulate and then stack testing once every three years.

According to § 63.11201(b), the biomass boiler must also comply with the following applicable work practice standards and management practices:

- Conduct a tune-up of the boiler biennially as specified in § 63.11223.
- Minimize the boiler's startup and shutdown periods following the manufacturer's recommended procedures.

The natural gas fired peaking boiler will not be subject to the requirements of Subpart JJJJJJ as the regulation does not apply to natural gas fired boilers.

For reference purposes, the following NESHAP standards will not apply to Highlands Ethanol:

40 CFR 63 Subpart B – Case-by-Case MACT

Control technology determinations for major sources of HAPs are described in 40 CFR 63 Subpart B. The requirements of §§63.40 through 63.44 of this subpart apply to any owner or operator who constructs or reconstructs a major source of HAPs after the effective date that the permitting authority adopts a program to implement Section 112(g) of the Clean Air Act and the effective date of a Title V Operating Permit program in the state or local jurisdiction in which the major source will be located unless the major source in question has been specifically regulated or exempted from regulation under a standard issued pursuant to Section 112(d), Section 112(h), or Section 112(j) and incorporated in another subpart of Part 63. The proposed facility will not be a major source of HAPs and therefore these requirements will not apply.

40 CFR 63 Subpart F - National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry

40 CFR 63 Subpart G - National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry for Process Vents, Storage Vessels, Transfer Operations, and Wastewater

40 CFR 63 Subpart H - National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks

Ethanol is not listed in Table 1 or Table 2 of 40 CFR 63 Subpart F [40 CFR §63.100], and the proposed facility will not be a major source of HAPs. Consequently, 40 CFR 63 Subparts F, G, and H will not apply.

40 CFR 63 Subpart I - National Emission Standards for Organic Hazardous Air Pollutants for Certain Processes Subject to the Negotiated Regulation for Equipment Leaks

None of the processes listed in the rule are to be located at the proposed facility [40 CFR §63.190], and the facility will not be a major source of HAPs. As a result, 40 CFR 63 Subpart I will not apply.

40 CFR 63 Subpart Q - National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers

The Cooling Tower will not be subject to the requirements of 40 CFR 63 Subpart Q because chromium-based water treatment chemicals will not be used, and the facility will not be a major source of HAPs [40 CFR §63.400(a)].

40 CFR 63 Subpart R - National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations)

As defined in the regulation, *bulk gasoline terminal* means any gasoline facility which receives gasoline by pipeline, ship or barge, and has a gasoline throughput greater than 75,700 liters per day (20,000 gallons per day) [40 CFR §63.421]. Because the proposed facility will not be defined as a bulk gasoline terminal and the proposed facility will not be a major source of HAPs, the rule will not apply.

40 CFR 63 Subpart Y - National Emission Standards for Marine Tank Vessel Loading Operations

The proposed facility will not be subject to the requirements of 40 CFR 63 Subpart Y because the proposed facility will not have the capability for marine tank vessel loading operations [40 CFR 63.560(a)].

40 CFR 63 Subpart OO - National Emission Standards for Tanks - Level 1

40 CFR 63 Subpart PP - National Emission Standards for Containers

40 CFR 63 Subpart WW - National Emission Standards for Storage Vessels (Tanks) - Control Level 2

Subparts OO, PP, and WW apply only when referenced by another regulation in 40 CFR Parts 60, 61, or 63. The regulations that will apply to the proposed facility do not require the air emission controls specified in Subpart OO [40 CFR §63.900], Subpart PP [40 CFR §63.920], or Subpart WW [40 CFR §63.1060].

40 CFR 63 Subpart TT - National Emission Standards for Equipment Leaks - Control Level 1 Standards

40 CFR 63 Subpart UU - National Emission Standards for Equipment Leaks - Control Level 2 Standards

Subparts TT and UU apply only when referenced by another regulation in 40 CFR Parts 60, 61, or 63. The regulations that will apply to the proposed facility do not require the air emission controls specified in Subpart TT [40 CFR §63.1000] or Subpart UU [40 CFR §63.1019].

40 CFR 63 Subpart VV - National Emission Standards for Oil-Water Separators and Organic-Water Separators

Subpart VV applies only when referenced by another regulation in 40 CFR Parts 60, 61, or 63. The regulations that will apply to the proposed facility do not require the air emission controls specified in Subpart VV [40 CFR §63.1040].

40 CFR 63 Subpart YY - National Emission Standards for Hazardous Air Pollutants for Source Categories: Generic Maximum Achievable Control Technology Standards

None of the processes listed in the rule are to be located at the proposed facility [40 CFR §63.1103(a)-(h)], so 40 CFR 63 Subpart YY will not apply.

40 CFR 63 Subpart EEEE - National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline)

The proposed facility's Product Storage Tanks and Product Loadout will not be subject to the requirements of 40 CFR 63 Subpart EEEE because the facility will not be a major source of HAPs [40 CFR §63.2334(a)].

40 CFR 63 Subpart FFFF - National Emission Standards for Hazardous Air Pollutants: Miscellaneous Organic Chemical Manufacturing

Because the proposed facility will not be a major source of HAPs, 40 CFR 63 Subpart FFFF will not apply [40 CFR §63.2435].

40 CFR 63 Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters – Major Sources

On March 21, 2011, USEPA published MACT standards for boilers located at major HAP sources. On March 21, 2011, USEPA also promulgated a reconsideration of the rule for major sources, including emission limits and monitoring requirements. On December 23, 2011, USEPA published changes to the major source boiler MACT rule. 40 CFR 63 Subpart DDDDD applies to facilities that own or operate an industrial, commercial, or institutional boiler or process heater that is located at, or is part of, a major source of HAPs. According to the EPA's definition, a major source is any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants. If a stationary source of HAPs is not a major source as previously defined, it is an area source.

As previously discussed, Highlands Ethanol will not be a major source of HAPs and consequently the MACT standards in Subpart DDDDD will not apply to the boiler.

4.1.4 Compliance Assurance Monitoring

The Compliance Assurance Monitoring requirements in 40 CFR 64 apply to pollutant-specific emissions units, located at a major source required to obtain a Part 70 permit, if the units satisfy certain criteria [40 CFR §64.2(a)]. Based on discussions with the FDEP, CAM requirements will be addressed in the Title V permit application and not in the preconstruction permit application.

4.1.5 Chemical Accident Prevention Provisions

The Chemical Accident Prevention provisions in 40 CFR 68 apply to facilities that have more than a threshold quantity of a regulated toxic or flammable substance in a process [40 CFR §68.10(a)]. The proposed facility will not conduct any activities involving more than a threshold quantity of a regulated substance, including any use, storage, manufacturing, handling, or on-site movement of such substances, or combination of these activities. This includes the proposed aqueous ammonia storage tank. However, the general duty provisions will apply to the proposed facility.

4.1.6 State Operating Permit Programs

The State Operating Permit Programs provisions in 40 CFR 70 are codified in Rule 62-213, F.A.C. *Operation Permit for Major Sources of Air Pollution.* The operating permit requirements are discussed in Section 4.2.4.

4.1.7 Stratospheric Ozone Protection Provisions

The Stratospheric Ozone Protection provisions in 40 CFR 82 Subpart F will apply to the proposed facility. The facility will comply with the materials, recycling, and systems maintenance requirements of this rule.

4.1.8 Acid Rain and Cross State Air Pollution Rules

Because the facility is proposing to generate power, other regulatory considerations include the Acid Rain Program and Cross State Air Pollution Rule (CSAPR) promulgated by USEPA on July 6, 2011 and modified June 5, 2012. Under CSAPR, Florida electric generating units (EGUs) rated 25 MW or greater are subject to the ozone season NO_X allowance (i.e., budget) requirements. Note that Florida was previously not subject to the NO_x Budget Program or Clean Air Interstate Rule (CAIR) requirements, and nonetheless both of these programs have been superseded by CSAPR. Implementation of CSAPR was scheduled to begin the first day of the 2012 ozone season (May 1), however on December 31, 2011 a federal appeals court stayed implementation of the rule. Florida and several other states are challenging the rule in the courts. Regardless, the total power generation capacity of the facility will be less than 25 MW, and therefore these rules would not apply.

4.2 **Florida State Requirements**

The emission sources for the proposed facility will comply with applicable regulations established by the FDEP. A summary of the state air quality requirements and their applicability to the proposed emission units for the proposed facility is discussed below.

4.2.1 Rule 62, Chapter 204, F.A.C. Air Pollution Control – General Provisions

The USEPA has established National Ambient Air Quality Standards (NAAQS) in 40 CFR 50 for the following criteria pollutants: SO_2, PM_{10}, $PM_{2.5}$, CO, O_3, NO_2, and Pb. Primary NAAQS define levels of air quality, which the USEPA judges are necessary with an adequate margin of safety to protect the public health. Secondary NAAQS define levels of air quality which the USEPA judges are necessary to protect the public welfare (i.e., wildlife, national monuments, vegetation, visibility, and property values) from any known or anticipated adverse effects of a pollutant. FDEP has adopted the NAAQS in Rule 62-204.800, F.A.C. Table 4-3 lists the NAAQS.

Chapter 204.340 establishes attainment designations for all pollutants and counties in Florida. Highlands County is designated as attainment or unclassified for all criteria pollutants. Class 1 and Class 2 allowable increments under the PSD program are also incorporated into in Chapter 204.800 by reference. A listing of these allowable increments is also provided in Table 4-3.

Chapter 204.800 incorporates several other federal regulations by reference that will apply to this project, including the NSPS, NESHAPS, MACT, CAM, USEPA test methods, and monitoring requirements under the Acid Rain program.

4.2.2 Rule 62, Chapter 210, F.A.C. Stationary Sources – General Provisions

Rule 62-210 establishes the general procedures for stationary sources including permit applicability, public notice requirements, emissions estimation and the use of air quality models. Regulation 62-210.200(190) defines a major source as one having potential emissions greater than 5 tons per year or more of lead, 30 tons per year or more of acrylonitrile, or 100 tons per year or more of any regulated pollutant. Regulation 62.210.370(2) identifies the methodologies for determining emissions for preconstruction review and for reporting requirements. Regulation 62.210.370(3) also requires that Title V sources submit an annual operating report to FDEP by April 1 of each year using DEP Form No. 62-210.900(5).

4.2.3 Rule 62, Chapter 212, F.A.C. Stationary Sources – Preconstruction Review

Chapter 212 establishes the preconstruction review requirements for sources required to obtain a construction permit under Chapter 210. This chapter includes general preconstruction requirements (212.300) as well as those under PSD (212.400), Nonattainment New Source Review (NNSR) (212.500) and Plantwide Applicability Limits (PALs) (212.720).

Table 4-3. Ambient Air Quality Standards, Ambient Increment Standards, and SILs

Pollutant	Averaging Period	NAAQS (μg/m³)	FDEP and Federal Allowable Increments Class I (μg/m³)	FDEP and Federal Allowable Increments Class II (μg/m³)	SILs Class I (μg/m³)	SILs Class II (μg/m³)
SO_2	1-Hour	196[a]	--	--	--	7.9
	3-Hour	1,300[b,c]	25[b]	512[b]	--	25[d]
	24-Hour	365[b]	5[b]	91[b]	1	5[d]
	Annual	80[d]	2[d]	20[d]	--	1[d]
PM_{10}	24-Hour	150[e]	8[b]	30[b]	1	5[d]
$PM_{2.5}$	24-Hour	35[f]	--	--	--	1.2
	Annual	15[f]	--	--	--	0.3
CO	1-Hour	40,000[b]	--	--	--	2,000[d]
	8-Hour	10,000[b]	--	--	--	500[d]
NO_2	1-Hour	188[g]	--	--	--	7.6
	Annual	100[d]	2.5[d]	25[d]	--	1[d]
O_3	8-Hour	147[h]	--	--	--	--
Pb	3-Month	0.15[j]	--	--	--	0.1

[a] The 3-year average of the 99th percentile of the daily 1-hour concentrations must not exceed standard.

[b] Arithmetic time-averaged concentration shall not exceed standard, except one exceedance allowed per year.

[c] Secondary standard.

[d] Arithmetic time-averaged concentration shall not exceed standard, no exceedances allowed.

[e] Expected number of days per calendar year with arithmetic time-averaged concentration above standard is equal to or less than one.

[f] The 3-year average of the 98th percentile of 24-hour concentrations must not exceed standard. The NAAQS was revised effective December 18, 2006 (71 FR 61144). Note that both the 1997 (65 μg/m³) and 2006 (35 μg/m³) standards are listed in 40 Code of Federal Regulations [CFR] Part 50 for the purposes of implementing $PM_{2.5}$ control strategies.

[g] The 3-year average of the 98th percentile of the daily maximum 1-hour concentration must not exceed standard.

[h] The 3-year average of the fourth-highest daily maximum 8-hour average ozone concentrations at each location within an area over each year must not exceed standard. On March 12, 2008, USEPA revised the ozone NAAQS to 147 μg/m³ (0.075 ppm) for the primary and secondary standards. FLDEP has not yet determined area designations under the new standard.

[i] Quarterly arithmetic average, no exceedances allowed.

[j] Rolling 3-month average, no exceedances allowed. Final rule signed October 15, 2008 (73FR66964).

μg/m³ = micrograms per cubic meter

As discussed in Section 4.1, the project will be subject to the PSD permitting requirements. For sources subject to PSD permitting requirements, Chapter 212.400 contains applicability provisions, control technology requirements, and procedures and standards for the ambient impact and additional impacts requirements. The project will meet all of the applicable requirements of Chapter 212.

Permitting fees and timelines for all FDEP permits are contained in Regulation 62-4.050 and 62-4.055. Air pollution permit fees for PSD permits are specified in Regulation 62-4.050(4)(a)1 as $7,500 per PSD applicable emission unit, with a reduced fee for similar units (e.g., each biogas fired engine). The regulatory permit processing timeline is 120 days if the Department does not request any additional information or clarification of the application. If additional information is requested, the applicant has up to 90 days to submit this information and the Department has an additional 90 days to review.

4.2.4 Rule 62, Chapter 213, F.A.C. Operation Permits for Major Sources of Air Pollution

Chapter 213 provides the operating permit requirements for major sources of air pollution. Chapter 213.205 establishes annual operating fees and specifies the methodology for the fee calculation. Operating fees are required to be paid annually between January 15 and March 1 of each year. Fees that are unpaid by March 1 are subject to an additional penalty of 50 percent of the fee plus interest. Chapter 213.400 specifies that major sources not covered under Chapter 213.300 (General Title V Permits) are required to obtain a Title V permit under this section.

Chapter 213.405 allows for concurrent review of a preconstruction and Title V Operating permit. However, sources that opt for this combined review must waive the preconstruction air permit review processing time requirement to accommodate the additional Title V permit review. Therefore, Highlands Ethanol is not requesting concurrent preconstruction and Title V review.

Chapter 213-420 requires that a major source file a Title V permit application 90 days prior to the expiration date of the facility's preconstruction permit but no later than 180 days after commencing operation. FDEP can also require an earlier submittal date in the preconstruction permit.

4.2.5 Rule 62, Chapter 296, F.A.C. Stationary Sources – Emissions Standards

Chapter 296 of Rule 62 provides emission standards for several pollutants and a variety of emission sources. This chapter includes emission limitations for specific facility categories and also establishes Reasonably Available Control Technology (RACT) for sources of NO_X, VOCs, and PM_{10}. Emission limits and work practice standards codified in 296.320 and 296.401 to 290.418 apply to all sources statewide. RACT requirements contained in 296.500, 296.600, and 296.700 apply to areas of the state that are designated as a nonattainment or maintenance area for ozone, lead, or particulate matter. The requirements of 296.500, 296.600, and 296.700 will not apply to the project.

Sections of Chapter 296 that will apply to the project are as follows:

- 320 – General Pollutant Emission Limiting Standards;
- 405 – Fossil Fuel Steam Generators with greater than 250 MMBtu/hr heat input;
- 406 – Fossil Fuel Steam Generators with less than 250 MMBtu/hr heat input; and
- 410 – Carbonaceous Fuel Burning Equipment.

Chapter 296.320, General Pollutant Emission Limiting Standards.

This chapter establishes emissions limitations and work practice standards for various process operations and emission units. This regulation is divided in four subparts: (1) volatile organic compounds or organic solvent emissions, (2) odor, (3) open burning, and (4) particulate emission limiting standards. The project will be subject to each of these subparts as follows.

Volatile Organic Compounds or Organic Solvent Emissions [62-296.320(1)]. This regulation prohibits any storage, processing, pumping, loading, unloading or handling of VOCs or organic solvents without the use of known and existing vapor emission control devices or systems that are required by the FDEP. The project will comply with this requirement by meeting NSPS and BACT requirements for VOC emissions sources at the facility including liquid/solid separation, propagation, fermentation, distillation, product and denaturant storage tanks, product loadout, stillage loadout, anaerobic digestion, biomass boiler, peaking boiler, emergency engines, and fugitive equipment leaks.

Objectionable Odor Prohibited [62-296.320(2)]. This regulation prohibits the discharge of air emissions that cause or contribute to an objectionable odor. The project will comply with this requirement by implementing BACT on the VOC emission sources that produce odorous emissions.

Permitted Open Burning [62-296.320(3)]. This regulation allows open burning in accordance with 62.256.700 and when the FDEP determines that open burning is the only available method of disposal available and authorizes the burning by issuing an air permit. Rule 62-256 prohibits open burning of vegetative debris and untreated wood with the exception of yard waste, tree cutting debris, land clearing debris, storm generated debris, insect or disease infested vegetation, and debris for recreational or ceremonial activities. In addition, 62.256.700(7) regulates the open burning of specific agricultural related materials including polyethylene agricultural plastic; damaged, nonsalvageable, untreated wood pallets; and packing material that cannot feasibly be recycled. The project will comply with the open burning requirements of 62-296.320 and 62-256.

General Particulate Emission Limiting Standards [62-296.320(4)]. This regulation limits particulate matter emissions from emission units that are not subject to a particulate matter or opacity emission limits elsewhere in Chapter 296. Processes subject to this regulation include feedstock receiving, the product loadout flare, the lime storage and handling system, the biogas flare, and the cooling tower. Regulation 296.320(4) limits particulate emissions in pounds per hour based on the process rate in tons per hour.

Chapter 296.340/296.341. Regional Haze/Best Available Retrofit Technology

These chapters establish regional haze applicability, determination of Best Available Retrofit Technology (BART) eligible sources, and the methodology for determining source specific BART. The boilers are exempt from BART applicability in accordance with 62-296.340(5)(a) as these units are located greater than 100 kilometers from all Class 1 areas and the sum of potential SO_2, NO_x, PM_{10}, and $PM_{2.5}$ emissions from these units is less than 1,000 tons per year.

Chapter 296.405. Fossil Fuel Steam Generators with greater than 250 MMBtu/hr Heat Input, New and Existing Emission Units

This chapter establishes emission standards for new and existing units that would be subject to permitting requirements pursuant to Regulation 62-210.300(3), F.A.C. and those units that would meet the criteria for an insignificant activity under Regulation 62-213.430(6)(b). Chapter 296.405 applies to the biomass boiler when natural gas is combusted. New sources subject to this regulation must meet visible emissions as well as emissions standards for NO_X, SO_2 and particulate matter specified in NSPS Subpart Da:

- 0.2 lb/MMBtu NO_X
- 0.15 lb/MMBtu SO_2
- 0.015 lb/MMBtu PM
- Visible emissions < 20%

Chapter 296.406. Fossil Fuel Steam Generators with less than 250 MMBtu/hr Heat Input, New and Existing Emission Units

This chapter establishes emission standards for new and existing units that would be subject to permitting requirements pursuant to Regulation 62-210.300(3), F.A.C. and those units that would meet the criteria for an insignificant activity under Regulation 62-213.430(6)(b). Chapter 296.406 applies to the natural gas-fired peaking boiler. Emission limits for PM and SO_2 prescribed by this chapter must meet BACT. A top down BACT analysis for the peaking boiler is provided in Section 5.

Visible emission requirements that will apply to the boilers while firing natural gas are as follows:

- 20 percent opacity, except for one six minute period per hour during which the opacity shall not exceed 27 percent, or one two minute period per hour during which the opacity shall not exceed 40 percent.

The facility will only be allowed one of the two 20 percent exception options in its preconstruction and operating permits.

Chapter 296.410. Carbonaceous Fuel Burning Equipment

This chapter establishes particulate and visible emissions standards for new and existing fuel burning equipment fired with carbonaceous fuel as defined in 62-210.200. Carbonaceous fuel is defined as "solid materials composed primarily of vegetative matter such as tree bark, wood waste, or bagasse." For burners with a heat input capacity greater than 30 MMBtu/hr (i.e., the biomass boiler and peaking boiler), particulate matter emissions are limited to 0.2 lb/MMBtu heat input of carbonaceous fuel and 0.1 lb/MMBtu heat input of fossil fuel. Particulate emissions from the biomass boiler will be well below these limits.

Visible emissions for the biomass boiler are limited to 30 percent opacity, except for one two minute period per hour where visible emissions may have a smoke density of 40 percent. Test methods for particulate matter and visible emissions shall be conducted using FDEP Methods 5 and 9, respectively (62-297).

4.2.6 Rule 62, Chapter 297, F.A.C. Stationary Sources – Emissions Monitoring

This regulation documents the test methods to be used to demonstrate compliance with applicable emission limits established in preconstruction permits and Chapter 296 of Rule 62. This regulation also specifies the requirements for stack test ports, test reports, and alternate procedures. USEPA test methods are incorporated by reference in 62-204.800.

4.3 Non-Applicable Regulations

4.3.1 Nonattainment New Source Review

NNSR permitting requirements will not apply to the construction of the proposed facility because it will be located within Highlands County, which is designated as attainment for all criteria pollutants [62-204.340, 62-212.500, F.A.C.].

4.4 Summary of Requirements

Table 4-4 contains a summary of the applicable requirements and the compliance methods for emission sources at the proposed facility.

Table 4-4. Summary of Applicable Requirements and Compliance Methods

Emission Source	Applicable Requirement	Compliance Method (Control)
Facility	62-210, F.A.C.	Apply for preconstruction permit
	62-210, F.A.C.	Submit annual Operating Report
	62-212, F.A.C.	Obtain PSD preconstruction permit apply BACT
	62-213, F.A.C.	Apply for Title V Operating Permit 90 days prior to expiration of construction permit and no later than 180 days after commencing operation
	62-296.320(2), F.A.C.	Capture and control odor causing emissions
	62-296.320(3), F.A.C.	Comply with open burning requirements in Chapters 256 and 296
Liquid/Solid Separation	62-296.320(1), F.A.C.	Control VOC emissions as required
Propagation / Fermentation	62-296.320(1), F.A.C.	Control VOC emissions as required
Distillation	62-296.320(1), F.A.C.	Control VOC emissions as required
Product Shift Tank No. 1	62-296.320(1), F.A.C. 40 CFR 60 Subpart Kb	Control VOC emissions as required Fixed roof, RTO
Product Shift Tank No. 2	62-296.320(1), F.A.C. 40 CFR 60 Subpart Kb	Control VOC emissions as required Fixed roof, RTO
Product Shift Tank No. 3	62-296.320(1), F.A.C. 40 CFR 60 Subpart Kb	Control VOC emissions as required Fixed roof, RTO
Product Storage Tank	62-296.320(1), F.A.C. 40 CFR 60 Subpart Kb	Control VOC emissions as required Internal floating roof; RTO during loading/unloading

Table 4-4. Summary of Applicable Requirements and Compliance Methods (Continued)

Emission Source	Applicable Requirement	Compliance Method (Control)

Emission Source	**Applicable Requirement**	**Compliance Method (Control)**
Denaturant Storage Tank	62-296.320(1), F.A.C.	Control VOC emissions as required Internal floating roof (BACT)
Product Loadout	62-296.320(1), F.A.C.	Control VOC emissions as required
Storage Silos	62-296.320(4), F.A.C.	Process weight rate limit for PM, fabric filter
Stillage Loadout	62-296.320(1), F.A.C.	Control VOC emissions as required
Biogas Backup Flare	62-296.320(1), F.A.C. 40 CFR 60 Subpart A	Control emissions as required
Biomass Boiler	40 CFR 60 Db 62-296.320(1), F.A.C. 62-296.405, F.A.C. 62,296.410, F.A.C	Comply with Subpart Db SO_2, NO_x and PM limits Control VOC emissions as required 20 percent opacity, except for one six minute period per hour where opacity <= 27%, or one two minute period per hour where opacity <= 40% PM emissions <=0.2 lb/MMBtu for biomass and 0.1 lb/MMBtu for fossil fuel. Opacity ,= 30% except one two *minute period* per hour where *opacity* <=40%
Peaking Boiler	62-296.320(1), F.A.C. 62-296.406, F.A.C. 40 CFR 60 Subpart Dc	Control VOC emissions as required Meet BACT for SO_2 and PM 20% Opacity
Emergency Generators	62-296.320(1), F.A.C. 40 CFR 60 Subpart IIII 40 CFR 63 Subpart ZZZZ	Control VOC emissions as required Install certified engines, limit fuel sulfur content
Fire Pump	40 CFR 60 Subpart IIII 40 CFR 63 Subpart ZZZZ	Install certified engines, limit fuel sulfur content
Fugitive Equipment Leaks	62-296.320(1), F.A.C. 40 CFR 60 Subpart VVa	Control VOC emissions as required Leak detection and repair (LDAR) program for VOCs

5.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

This section documents the top-down BACT analysis for the proposed Highlands Ethanol project in accordance with guidance presented in USEPA's *Draft New Source Review Workshop Manual* (USEPA Draft, 1990b) and regulations contained in Title 62, Chapter 212, Section 400 of the Florida Administrative Code (62-212.400 F.A.C.).

The determination of BACT involves assessing the feasibility of applying emission control alternatives to an emission unit taking into account technological, economic, energy, and secondary environmental impacts. The BACT evaluation process starts with the characterization of the "base" level of emission control proposed for the source. That is, establishing the inherent design and operating features of the emission unit and its pollutant emission rates as it is proposed to be installed. Each BACT alternative is then evaluated in terms of additional control provided beyond the existing base case.

Section 5.1 presents the applicability of BACT by pollutant and emission source. Section 5.2 presents an overview of the "top-down" BACT assessment procedure used in this analysis. Section 5.3 presents control technology determinations for all emission sources of each pollutant subject to BACT review. Section 5.4 summarizes the proposed BACT emission limits.

5.1 BACT Applicability

The following presents the pollutants and emission sources subject to BACT review.

5.1.1 Pollutants Subject to BACT

Pollutants that are subject to PSD review are subject to the BACT requirements. BACT is defined as an emission limitation based on the maximum degree of reduction, on a case-by-case basis, taking into account energy, environmental, and economic impacts. As discussed in Section 4, the major source threshold for the Highlands Ethanol facility is 250 tons per year for criteria pollutants, and 100,000 tons per year for GHGs as CO_2e. Once a facility is considered a major source for one criteria pollutant, the lower significance thresholds apply for the other criteria pollutants. Therefore, the facility is subject to PSD review, and hence BACT, for each pollutant with potential to emit (PTE) greater than the major source threshold, or for pollutants with PTE greater than significance thresholds if one pollutant is greater than the major source threshold. The total maximum estimated PTE for each criteria pollutant to be emitted from the proposed facility was compared to the respective PSD major source and significance thresholds for each pollutant to determine PSD applicability. As was discussed in Section 4.1.1 and summarized in Table 4-1, the project will exceed the major source threshold for $CO2_e$. In addition, the project will exceed the PSD significance thresholds of 40 tpy for VOCs, SO_2, and NO_X; 100 tpy for CO; 15 tpy for PM_{10}; and 10 tpy for $PM_{2.5}$. Therefore, the project will be subject to PSD and BACT for these criteria pollutants.

5.1.2 Emission Sources Subject to BACT

For a facility subject to PSD and BACT, each emission unit that emits a regulated pollutant for which total facility emissions exceed PSD applicability or significant emission thresholds is subject to the control technology review. Table 5-1 contains a listing of the emission sources that will emit the pollutants subject to BACT. The pollutants emitted, and thus pollutants for which BACT will be required for each source, are indicated in the columns to the right of the emission source description. Point sources are listed first, followed by fugitive sources. Detailed emission calculations by emission source are presented in Appendix B. However, for the purposes of this BACT analysis, the many small sources and the few large sources of criteria pollutant emissions have been logically grouped to avoid redundancy in the analysis by addressing numerous similar, related sources as groups.

Table 5-1: Emission Sources Subject to BACT

	Pollutant Emitted Subject to BACT Review						
Sources	**VOC**	**NO_X**	**CO**	**SO_2**	**PM_{10}**	**$PM_{2.5}$**	**GHG**
Point Sources							
Liquid/Solid Separation	•						
Fermentation/Distillation/Propagation	•						•
Product/Denaturant Storage	•						
Product Loadout	•						
Miscellaneous Storage Silos					•	•	
Anaerobic Digestion / Backup Flare	•			•			•
Cooling Tower	•				•	•	
Steam Production	•	•	•	•	•	•	•
Emergency Engines	•	•	•	•	•	•	•
Fugitive Sources							
Stillage Loadout	•						
Equipment Leaks	•						
Roadway Emissions					•	•	

5.2 BACT Methodology

The following describes the "top-down" BACT evaluation methodology adopted by the USEPA and presented in the USEPA's *Draft New Source Review Workshop Manual* (USEPA Draft, 1990b). The method is the standard procedure accepted by the USEPA and state and local regulatory agencies, including the FDEP, for determining BACT for sources subject to PSD permitting.

The "top down" method for determining BACT requires that emission control technologies be ranked in descending order of control effectiveness and that the most effective technology that is achievable, given economic, energy and environmental impacts, be established as BACT. The steps involved in this evaluation are as follows:

- Step 1: Identify available control alternatives;
- Step 2: Eliminate technically infeasible options;
- Step 3: Rank remaining options by control effectiveness;
- Step 4: Evaluate energy, environmental, and economic impacts of remaining options; and
- Step 5: Select BACT and document results.

The first step in determining BACT is the review of available control options. Each option is evaluated from the standpoint of technical feasibility for application to the subject source. All of the technically feasible options are then ranked in descending order of control efficiency. Consistent with USEPA and FDEP policy, the BACT analysis then proceeds in the "top-down" format. In the top-down BACT analysis, the most effective control options that are feasible for implementation are evaluated on the basis of economic, energy, and secondary environmental impacts. If the "top" alternative is economically feasible and does not have detrimental energy or environmental impacts, then the "top" alternative is selected as BACT.

If the most stringent technology is determined to be "not achievable" based on technical considerations, or economic, energy, or environmental impacts, then the next most stringent alternative is evaluated in the same fashion. The analysis proceeds until a technology cannot be eliminated from consideration based on the economic, energy, and secondary environmental impacts. This technology, which could be the inherent equipment design, is then determined to represent BACT for the subject source. If all of the technically feasible control technologies are shown to be economically infeasible, then BACT may be set at no control for the specific source in question.

If there is only a single feasible option, or if the "top" alternative is selected, then no further analysis is required. If two or more technically feasible options are identified, the next three steps are applied to identify and compare the economic, energy, and environmental impacts of the options. Technical considerations and site-specific sensitive issues will often play a role in BACT determinations. If the most stringent technology is rejected as BACT, the next most stringent technology is evaluated, and so on.

5.2.1 Step 1: Identify Available Control Alternatives

The first step is identification of available technically feasible control technology options, including consideration of transferable and innovative control measures that may not have previously been applied to the source type under analysis. Any control technology that has previously been determined to represent BACT for a similar source type should be included in the BACT analysis. Technologies that are deemed to meet Lowest Achievable Emission Rate

(LAER) also need to be considered in the BACT analysis. Technically feasible control alternatives that previously have been determined to be LAER usually represent the top level of control in the BACT analysis. In addition to demonstrated controls for the source being evaluated, available control alternatives identified should also include controls for similar source categories and exhaust gas streams through technology transfer. The minimum requirement for a BACT proposal is an option that meets federal NSPS limits or other minimum state or local requirements that would prevail in the absence of BACT decision-making, such as RACT or other FDEP emission standards. After elimination of technically infeasible control technologies, the remaining options are to be ranked by control effectiveness.

To identify options for each class of equipment, various sources of information were reviewed to determine appropriate emission control technologies to be considered in the BACT analysis. These sources included:

- USEPA's RACT/BACT/LAER Clearinghouse (RBLC), which is available on-line through USEPA's Technology Transfer Network (TTN) website (USEPA, 2012) ;
- Federal, state and local NSR permits and associated inspection and performance test reports;
- Literature provided by control technology vendors;
- Environmental engineers and consultants;
- Technical journals, reports and newsletters;
- USEPA's NSR bulletin board; and
- Industrial Trade Associations and Organizations.

5.2.2 Step 2: Evaluate Technical Feasibility of Control Alternatives

The second step identifies the technical feasibility of the control alternatives identified in Step 1 with respect to the specific emission unit in question. Control alternatives that have been demonstrated (i.e., installed and successfully operated) on the same source type as the unit under review are generally deemed technically feasible. Stack emissions data from a known reference method or certified CEMS are an acceptable level of quality for confirming the feasibility of meeting a BACT emission limit.

Control alternatives that have not been demonstrated on the same type of emission unit under review must be commercially available to be considered in the BACT analysis. A technical evaluation is then made on the applicability of the alternative to the source in question. The technical feasibility evaluation is based on the following:

- Physical and chemical characteristics of the gas stream;
- Similarities and differences between the proposed source and other sources on which the technique has been demonstrated; and

- Unique technical difficulties associated with applying the technique (e.g., size of the unit, location of the proposed site, expected operating problems, availability of required utilities).

Assessing the technical feasibility of emission control alternatives is discussed in USEPA's draft "New Source Review Workshop Manual" previously referenced. Using terminology from this manual, if a control technology has been "demonstrated" successfully for the type of emission source under review, then it would normally be considered technically feasible. For an undemonstrated technology, technical feasibility is determined by "availability" and "applicability." An available technology is one that is commercially available, meaning that it has advanced through the following steps:

- Concept stage;
- Research and patenting;
- Bench scale or laboratory testing;
- Pilot scale testing;
- Licensing and commercial demonstration; and
- Commercial sales.

The term applicability entails the following concepts (as quoted from USEPA's draft "New Source Review Workshop Manual," pages B.18-B-19):

> *"Technical judgment on the part of the applicant and the review authority is to be exercised in determining whether a control alternative is applicable to the source type under consideration. In general, a commercially available control option will be presumed applicable if it has been or is soon to be deployed (e.g., is specified in a permit) on the same or similar source type. Absent a showing of this type, technical feasibility would be based on examination of the physical and chemical characteristics of the pollutant-bearing gas stream and comparison to the gas stream characteristics of the source types to which the technology had been applied previously. Deployment of the control technology on an existing source with similar gas stream characteristics is generally sufficient basis for concluding technical feasibility barring a demonstration to the contrary."*

If a control alternative is determined to be technically infeasible for application to the subject source, then supporting information demonstrating the technical infeasibility must be presented. The documentation should demonstrate based on physical, chemical, and engineering principles that technical difficulties would preclude the successful application of the control alternative on the specific emission unit. Control alternatives that are demonstrated to be technically infeasible are eliminated from further consideration in the BACT evaluation.

5.2.3 *Step 3: Rank Technically Feasible Control Alternatives*

In Step 3, technically feasible control alternatives (i.e., those that were deemed technically feasible in Step 2) are ranked in order of overall control effectiveness for the pollutant under review. The most effective control alternative is evaluated first as BACT. If the proposed control technology for the new emission unit is the top level of control and determined to be BACT, then cost data and related energy and environmental impacts for other emission control alternatives do not need to be evaluated. However, if alternative control options are considered that are not top level control options, then the BACT evaluation must review economic, energy and secondary environmental impacts.

5.2.4 *Step 4: Evaluate Economic, Energy and Secondary Environmental Impacts*

In Step 4, if the BACT proposal is not the top level of control from the technically feasible alternatives, the applicant must demonstrate why the top level technology does not represent BACT for the project. This demonstration is based on the economic, energy, or secondary environmental impacts of that technology and the analysis then considers the next most stringent control technology. The analysis continues until a control alternative cannot be eliminated from consideration based on economic, energy, or secondary environmental impacts. The following describes the procedures for quantifying economic, energy, and secondary environmental impacts.

5.2.4.1 Economic Impacts

Economic impacts are calculated when necessary by quantifying the total capital investment, annual operating costs, and pollutant removal cost-effectiveness for each alternative under consideration. In general, the cost data used in this analysis are accurate to within ±30 percent.

The total capital investment is comprised of basic equipment costs and direct and indirect installation costs. Direct installation costs include costs for foundations and supports, erecting and handling the equipment, electrical work, piping, insulation and painting. Indirect installation costs include engineering costs, construction and field expenses, contractor fees, royalty/license fees, process modeling, start-up and performance test costs, and contingencies.

Annual operating costs include direct costs and indirect costs. Direct annual costs include costs for raw materials, utilities (steam, electricity, fuel, and water), waste treatment and disposal, maintenance materials, replacement parts, and operating, supervisory, and maintenance labor. Indirect annual costs include administrative charges, property taxes, insurance, and capital recovery. The capital recovery cost is the annualized cost of the total capital investment (i.e., capital investment amortized over the expected life of the control equipment to give a uniform annual payment necessary to repay the investment).

The cost effectiveness of the control alternative is calculated by dividing its total annual operating cost by the amount of emissions that the control alternative removes. Cost effectiveness is the measure by which regulatory agencies judge the economic feasibility of applying the control alternative under review.

The cost/economic impacts analyses provided in this BACT assessment are based primarily on budgetary-level capital and operating cost assessments estimated using the methodology in the USEPA's Office of Air Quality Planning and Standards (OAQPS) *Air Pollution Control Cost Manual, Sixth Edition* (EPA 452/B-02-001) (USEPA, 2002b). Some costs estimated from data in this manual were based on equipment cost data obtained in earlier years. These data were escalated, where necessary, to be representative of current costs by applying the appropriate cost escalation indices from the Marshal & Swift Equipment Cost Index (*Chemical Engineering*, October 2008). In some cases equipment cost data were based on budgetary estimates or quotations obtained directly from a control equipment vendor for a BACT assessment for another facility and scaled to the appropriate size required for the Highlands Ethanol plant using the engineering "Six-Tenth's Rule" for scaling of cost estimates, which accounts for economies of scale realized when increasing equipment size (Peters et al., 2002). In select cases, vendor budget estimates were available specifically for the project. The costing method employed is described in each case.

5.2.4.2 Energy Impacts

The energy requirements of the control alternative are quantified when necessary to determine whether the use of that alternative results in any significant or unusual positive or negative energy impacts. Only direct energy impacts are considered. Indirect energy impacts, such as energy to produce raw materials for construction or operation of control equipment, are not considered.

5.2.4.3 Secondary Environmental Impacts

The analysis of secondary environmental impacts is conducted by quantifying the solid, liquid, and gaseous discharges from the control alternative under consideration. Secondary environmental impacts include wastewater streams that could have an impact on water quality and land use, solid and hazardous wastes such as spent catalysts, impacts on visible emissions such as cooling tower vapor, and additional air emissions (including air toxics, GHGs, and pollutants other than the one under review). In addition, significant differences in noise levels, radiant heat or dissipated static electrical energy may also be considered.

5.2.5 Step 5: Determine BACT

The most effective emission control alternative that cannot be eliminated from consideration based on economic, energy or secondary environmental impacts is determined to be BACT.

5.3 BACT Evaluation for the Highlands Ethanol Project

The following sections provide the BACT assessment for the Highlands Ethanol facility for each regulated pollutant subject to BACT review. Within each section, a separate assessment is provided for each emission source that emits the BACT pollutant as detailed in Table 5-1. For each pollutant/process combination, the analysis follows the top down procedure outlined in Section 5.2 above.

It is important to recognize that Highlands Ethanol's cellulosic ethanol production process is a proprietary process and the Highlands Ethanol facility will be the first commercial production-scale facility to use this process in the production of fuel grade ethanol. Most recently permitted ethanol production facilities are corn-based ethanol facilities. As a result, there is not a direct correlation between the specific process operations identified in the RBLC Clearinghouse and existing permits for corn ethanol facilities and the proposed Highlands Ethanol facility. Nevertheless, many of the production processes used in corn-based ethanol production are analogous and emission control determinations for these processes may be transferable. Other supporting project operations such as boilers, engines, cooling towers, etc. are not unique to Highlands Ethanol's process and documentation of prior determinations for these supporting processes is more straightforward.

To identify potential BACT options for each process/pollutant combination, AMEC compiled an extensive database of relevant prior BACT/permit data. BACT data were first obtained through a review of the RBLC Clearinghouse for process types that have direct or transferable applications to the various processes at the proposed Highlands Ethanol facility. The following RBLC processes were reviewed:

- Alcohol production (including alcohol beverage, alcohol fuel, and other alcohol production);
- Biomass boilers with heat input capacities greater than 250 MMBtu/hr;
- Biomass boilers with heat input capacities between 100-250 MMBtu/hr;
- Cooling towers;
- Internal combustion engines;
- Natural gas boilers with heat input capacities between 10-250 MMBtu/hr;

In addition, AMEC identified a promulgated state regulation in Indiana that requires VOC emission controls for ethanol production facilities, which is considered in determining BACT. Fuel ethanol production plants constructed or modified in Indiana after April 1, 2007 are subject to 326 Indiana Administrative Code (IAC) 8-5-6 (Fuel Grade Ethanol Production at Dry Mills) if the plant uses dry milling and has combined potential VOC emissions of 25 tons or more per year from fermentation, distillation, and dehydration; Distillers dry grain and solubles (DDGS) dryer or dryers; and, ethanol load-out operations. Plants subject to the requirements of 326 IAC 8-5-6 are required to control VOC emissions by installing one of the following control devices:

- A thermal oxidizer with an overall control efficiency not less than 98% or resulting in a VOC concentration of not more than 10 ppm;
- A wet scrubber with an overall control efficiency not less than 98% or resulting in a VOC concentration of not more than 20 ppm; or
- An enclosed flare with an overall control efficiency of not less than 98%.

To augment the information obtained from the RBLC Clearinghouse and state regulations, AMEC also conducted a thorough search of air permits for facilities likely to have analogous processes within the State of Florida and in other states within USEPA Region 4. Our search included recently permitted facilities, or facilities whose permit applications are under review by the regulatory agency. Ethanol production facilities (both fuel alcohol and beverage alcohol), biodiesel production facilities (which have some relevant emission units), and facilities with biomass boilers, cooling towers, or storage tanks/loading racks were included to identify technically feasible technologies. Biomass, as referred to in the following analysis, includes stillage, biosolids and biogas. AMEC identified the following permits for inclusion in our analysis in addition to the RBLC Clearinghouse data:

Florida

- U.S. Sugar Corporation – Clewiston Sugar Mill & Refinery (biomass boiler);
- Bartow Ethanol of Florida L.C. (ethanol production);
- United States EnviroFuels, LLC – Port Sutton Ethanol Facility (ethanol production);
- United States EnviroFuels, LLC – Port Manatee Ethanol Facility (ethanol production);
- Progress Energy Florida, Inc. – Anclote Power Plant (cooling tower);
- Progress Energy Florida, Inc. – Crystal River Power Plant (cooling tower);
- Murphy Oil USA, Inc (biodiesel production).
- Southeast Renewable Fuels (ethanol production);
- INEOS New Planet BioEnergy (ethanol production); and
- Highlands EnviroFuels, LLC (ethanol production).

Georgia

- Greenway Renewable Power, LLC (biomass boiler);
- Earth Resources, Inc. – Plant Carl (biomass boiler);
- The Procter & Gamble Paper Products Company (biomass boiler);
- Southwest Georgia Ethanol, LLC (ethanol production);
- Wind Gap Farms (biomass boiler);

- Yellow Pine Energy Company, LLC (biomass boiler); and
- North Star Jefferson Renewable Energy Facility (biomass boiler).

Mississippi

- Three Rivers Biofuels, LLC (biodiesel production);
- Tri States Petroleum Products LLC (biodiesel production);
- North Mississippi Biodiesel, Inc. (biodiesel production);
- Mound Bayou Refiner Inc. (biodiesel production);
- CFC Transportation, Inc. (biodiesel production);
- Southern Ethanol Company, LLC – Rosedale (ethanol production);
- Southern Ethanol Company, LLC – Amory (ethanol production);
- Delta Ethanol, LLC (ethanol production); and
- Elevance Renewable Sciences (biodiesel production).

Alabama

- Athens Biodiesel, LLC (biodiesel production);
- Alabama Biodiesel Corporation (biodiesel production); and
- Dunhill Entities, L.P.(loading terminal for biodiesel, gasoline, and ethanol).

Kentucky

- Bluegrass Bioenergy, LLC (ethanol production);
- Buffalo Trace Distillery Inc. (ethanol production);
- Commonwealth Agri-Energy, LLC (ethanol production);
- Constellation Spirits Inc. (ethanol production);
- Countrymark Cooperative, LLP (storage tanks and loading racks);
- The Four Rivers BioEnergy Company, Inc. (biodiesel production);
- Four Roses Distillery, LLC (ethanol production);
- Heaven Hill Distilleries, Inc. (ethanol production); and
- Kentucky 5 Star Energy, LLC (ethanol production).

North Carolina

- Suez Energy BioPower, Inc. – North Cove (biomass boiler).

Finally, based on industry knowledge, AMEC is also aware of two very recently permitted facilities outside of Region 4 that have sources analogous to the proposed facility: the Corn Plus facility in Winnebago, Faribault County, Minnesota, and the Nacogdoches Power facility in Nacogdoches County, Texas. The Corn Plus facility is an ethanol production facility that utilizes a fluidized bed biomass boiler similar to the boiler design proposed for the Highlands Ethanol facility. The primary difference is that Corn Plus combusts corn syrup and Highlands Ethanol will combust stillage cake, biosolids and biogas. The Nacogdoches Power facility also incorporates a fluidized bed biomass boiler fired with wood waste. Given the similarities of these facilities to the proposed project, AMEC included data from both the Corn Plus and Nacogdoches Power permits in the database as well.

The BACT review database used in this analysis contains over one-thousand records of prior permit decisions potentially relevant to the various emission processes at Highlands Ethanol, and for brevity and consistency, is referred to as the "permit database" in the remainder of this analysis. We believe that this database is representative of the level of control that currently exists in the industry for ethanol production facilities such as that proposed by Highlands Ethanol.

For each process identified in the database, AMEC determined which corresponding process, if any, was relevant to the proposed Highlands Ethanol processes. AMEC was then able to sort the database for each Highlands Ethanol process to obtain a subset of prior BACT and permit records relating to that process. This information was used to determine the available control technologies and corresponding levels of control to be considered in the BACT analysis.

5.3.1 Volatile Organic Compounds

As detailed in Table 5-1, the specific sources of VOC emissions at the Highlands Ethanol facility include:

- Liquid/Solid Separation;
- Fermentation/Distillation/Propagation;
- Product/Denaturant Storage;
- Product Loadout;
- Anaerobic Digestion;
- Cooling Tower;
- Steam Production;
- Emergency Engines;
- Stillage Loadout; and
- Fugitive Equipment Leaks.

The BACT evaluation for each of these sources of VOC emissions is presented in the following sections.

5.3.1.1 Liquid/Solid Separation

Liquid/solid separation is used to separate the liquid hemicellulosic stream from the solid cellulosic stream in preparation for fermentation. The stream entering liquid/solid separation from hydrolysis has trace levels of organics that are soluble in water. Representative of these organics are acetic acid and furfural. While soluble in water, a small fraction of the trace levels of organics are expected to evaporate in the process.

Available Control Alternatives

Liquid/solid separation is unique to Highlands Ethanol's proprietary acid hydrolysis process and there are no currently permitted facilities in the permit database that utilize such a process in ethanol production. However, the VOCs emitted from the process are soluble in water and primarily include acetic acid, furfural, and hydroxymethylfurfural. The water solubility of the constituents is analogous to the water solubility of organic compounds emitted in the fermentation and distillation processes. The fermentation process is also used in corn ethanol production and is included in the permit database compiled for this BACT analysis. Therefore, AMEC used the permit database records for fermentation to represent the currently available control alternatives and the expected BACT level of control for the liquid/solid separation process.

The permit database records relating to fermentation are presented in Appendix E, Table E-1. There are 31 facilities in the database relating to fermentation. Four (4) facilities have no control. Three (3) facilities use a combination of wet scrubbing and regenerative thermal oxidation. Twenty six (26) facilities use wet scrubbing. Based on this information, the available control alternatives for this process include wet scrubbing and thermal oxidation.

Ranking of Technically Feasible Controls

Based on the permit database, the current level of BACT control in the industry for the fermentation process, which has been determined to be analogous to liquid/solid separation, ranges from 95% to 99%. Because the pollutants are water soluble, wet scrubbing and thermal oxidation can provide equivalent levels of control. Highlands Ethanol is proposing to control VOC emissions from the liquid/solid separation process with a regenerative thermal oxidizer (RTO), which represents the top level of control. Therefore, an analysis of economic, energy, and environmental impacts is not required.

Determination of BACT

Highlands Ethanol proposes to control VOC emissions from the liquid/solid separation process with an RTO to satisfy BACT. The current level of BACT control in the industry ranges from 95 to 99 percent as shown in Table E-1. In addition, as discussed in Section 5.3, Indiana has mandated a control level of 98 percent for ethanol production facilities constructed after April 1, 2007. Five (5) facilities for which control level data are available are permitted at a level of 95 percent control, two (2) facilities are permitted at 97 percent control, six (6) facilities are permitted at 98 percent control, and only three (3) facilities are permitted at greater than 98 percent control. Specific control efficiencies are not specified for ten (10) of the facilities and four (4) are listed with no control.

Highlands Ethanol has determined that 99 percent control is achievable with the RTO. This is better than the level of control for the Highlands EnviroFuels (HEF), LLC facility recently approved by the FDEP. It is also equivalent to or better than the control level required for new facilities in Indiana and all of the identified facilities in the database. Therefore, BACT for VOC emissions from liquid/solid separation is an RTO achieving 99 percent control. The RTO is also being proposed as BACT for a number of other process areas at the facility, and a discussion of the proposed VOC BACT emission limits for the RTO are provided later in this section.

5.3.1.2 Fermentation/Distillation/Propagation

Fermentation is the biological process that occurs when microorganisms convert sugars to produce ethanol, carbon dioxide (CO_2), and water. Distillation processes are used to separate and concentrate ethanol from the fermented mixture. Propagation is the biological process used to grow the proprietary enzyme and microorganisms for fermentation. Ethanol will be the primary VOC that is emitted from these processes, although trace VOCs such as acetaldehyde and ethyl acetate will also be emitted.

Available Control Alternatives

The permit database records relating to fermentation are presented in Table E-1, while those relating to distillation are presented in Table E-2. There are 31 facilities in the database relating to fermentation. Four (4) facilities have no control. Three (3) facilities use a combination of wet scrubbing and regenerative thermal oxidation. Twenty six (26) facilities use wet scrubbing. Based on this information, the available control alternatives for fermentation include wet scrubbing and thermal oxidation.

Given the water soluble nature and relatively low concentrations of the organics in the fermentation vent stream, the most often applied control option is a wet scrubber, as evidenced by the fact that 74 percent of the identified facilities use this technology.

There are 18 facilities in the database relating to distillation operations (Table E-2). Three facilities have no control. Two facilities use thermal oxidation, most likely because at these facilities the distillation vent stream is combined with the DDGS dryer exhaust, which is a high VOC process exhaust that does not exist in the proposed facility. One facility uses a combination of wet scrubbing and regenerative thermal oxidation. Eleven (11) facilities use wet scrubbing. Based on this information, the available control alternatives for distillation include wet scrubbing and thermal oxidation.

Ranking of Technically Feasible Controls

Based on the permit database, the current level of control in the industry for the fermentation and distillation processes ranges from 95% to 99% using either technology. Because the pollutants are water soluble, wet scrubbing and thermal oxidation can provide equivalent levels of control. Highlands Ethanol is proposing to use a wet scrubber to recover the ethanol followed by an RTO to control remaining VOC emissions, which represents the top level of control. Therefore, an analysis of economic, energy, and environmental impacts is not required.

Determination of BACT

Highlands Ethanol proposes to control VOC emissions from the fermentation and distillation processes with an RTO to satisfy BACT. Highlands Ethanol proposes to control VOC emissions from the fermentation and distillation processes with an RTO to satisfy BACT. The current level of BACT control in the industry ranges from 95 to 99 percent as shown in Tables E-1 and E-2. In addition, as discussed in Section 5.3, Indiana has mandated a control level of 98 percent for ethanol production facilities constructed after April 1, 2007.

Highlands Ethanol has determined that 99 percent control is achievable with the RTO. This is better than the level of control for the Highlands EnviroFuels (HEF), LLC, facility recently approved by the FDEP. It is also equivalent to or better than the control level required for new facilities in Indiana and all of the identified facilities in the database. Therefore, BACT for VOC emissions from fermentation, distillation and propagation is an RTO achieving 99 percent control. The RTO is also being proposed as BACT for a number of other process areas at the facility, and a discussion of the proposed VOC BACT emission limits for the RTO are provided later in this section.

5.3.1.3 Product and Denaturant Storage Tanks

The facility includes three (3) product shift tanks and one E95 storage tank. The facility also includes one gasoline (denaturant) storage tank. The product shift tanks will be fixed roof tanks and will have submerged fill pipes; these tanks will be vented to the ethanol absorber and subsequently the RTO. Gasoline is used as a denaturant to render the ethanol undrinkable. The denaturant and E95 tank will each be designed with an internal floating roof to minimize VOC emissions.

Available Control Alternatives

The permit database records relating to volatile organic storage tanks are presented in Appendix E, Table E-3. There are 22 facilities in the database relating to storage tanks. Four facilities have no identified control on storage tanks. Three facilities utilize submerged fill pipes for VOC control. Thirteen facilities use internal floating roofs for VOC control. One facility utilizes submerged fill pipes in conjunction with internal floating roofs, and one facility utilizes submerged fill pipes and vents the tanks to a condenser.

Based on the information in the database, the available control options for storage tanks include internal floating roofs, venting to a control device, and submerged pipe filling. In addition, fixed roof tanks can be equipped with a pressure/vacuum conservation vent, which allows the tanks to operate at a slight internal pressure and prevents the release of vapors to the atmosphere during small changes in temperature, pressure, or liquid level (USEPA, 1996b).

All of these control technologies are technically feasible for application to the storage tanks at Highlands Ethanol.

<u>*Ranking of Technically Feasible Controls*</u>

The permit database does not contain any information relating to the level of control provided by the control options in use. However, estimates are available from USEPA. An internal floating roof and seals installed in a fixed roof tank can be used to minimize evaporation of product from the tank, with a control efficiency from 60 to 99 percent, depending on the type of roof and seals installed and the type of liquid stored (USEPA, 1997b). Vapor recovery systems to collect emissions from storage tanks and vent to a control device can have control efficiencies as high as 90 to 98 percent (USEPA, 1997b). For the top-down approach, internal floating roofs and venting the tanks to a control device are considered to provide an equivalent level of control and are the top control available. While not quantifiable, submerged filling and vapor conservation vents would not provide as high a level of control as internal floating roofs or venting the tanks to a control device.

Highlands Ethanol plans to install internal floating roofs to control VOC emissions from the E95 and denaturant storage tanks, which represents the top level of control for these two tanks. The three product shift tanks will be vented to the RTO.

<u>*Determination of BACT*</u>

Highlands Ethanol plans to install internal floating roofs on the E95 and denaturant storage tanks, which is the top level of control and represents BACT. For the product shift tanks, the tanks will be vented to the RTO, which is the top level of control and represents BACT.

5.3.1.4 Product Loadout

Product will be loaded onto tank trucks at a rate of 600 gallons per minute using submerged fill. Vapors displaced from the trucks will be exhausted to the RTO, which will provide 99% control efficiency for VOC emissions during the loading of product (ethanol) into trucks. The trucks are assumed not to be in dedicated ethanol service (i.e., some trucks will have returned from delivering gasoline).

Available Control Alternatives

The permit database records relating to product loadout are presented in Appendix E, Table E-4. There are 23 facilities in the database relating to product loadout. One facility has no control on product loadout. One facility uses an RTO. The remaining 21 facilities utilize a flare to reduce VOC emissions from product loadout. Based on this information, the available control alternatives for this process include thermal oxidation via either a flare or RTO.

Ranking of Technically Feasible Controls

Based on the permit database, the current level of control in the industry for product loadout ranges from 97 percent to 99 percent. The technologies in use provide an equivalent level of control and therefore either a flare or RTO represents the top level of control. Highlands Ethanol is proposing to use an RTO to control VOC emissions, which is the top level of control. Therefore, an analysis of economic, energy, and environmental impacts is not required.

Determination of BACT

Highlands Ethanol plans to employ an RTO to control VOC emissions from this process, which is the top level of control, and therefore represents BACT. The current level of BACT control in the industry ranges from 97 to 99 percent as shown in Table E-4. One facility for which control level data are available is permitted at a level of 97 percent control, eight facilities are permitted at 98 percent control, and two facilities are permitted at 99 percent control. Highlands Ethanol has determined that 99 percent control is achievable. This is better than the level of control for the Highlands EnviroFuels (HEF), LLC facility recently approved by the FDEP as well as the control level required for new facilities in Indiana. Therefore, BACT for VOC emissions from product loadout is an RTO achieving 99 percent control.

5.3.1.5 Anaerobic Digestion

Anaerobic digestion is used to produce biogas from the organics in the thin stillage from the ethanol production processes. Anaerobic digestion produces a biogas that contains flammable levels of methane (CH_4) that requires safe disposal methods to be adopted. Highlands Ethanol proposes to combust the biogas in the biomass boiler for the added benefit of energy recovery. During times when the biomass boiler is shut down, the biogas will be combusted with a flare having a rated capacity of 100 MMBtu/hr. Trace levels of organics in the biogas will also be combusted.

Available Control Alternatives

The permit database records relating to wastewater treatment are presented in Appendix E, Table E-5. There are four (4) facilities in the database relating to wastewater treatment. Two facilities have no control on wastewater treatment and two facilities control anaerobic digesters with a flare, with the highest level of VOC control listed at 98%. Based on this information, the available control alternatives for this process include flares. Given the high control level possible and the relatively low cost, the most logical BACT technology is burning the biogas in a boiler or a flare as evidenced by the permit data.

Ranking of Technically Feasible Controls

Based on the permit database, the highest level of control in the industry for wastewater treatment is 98 percent. To control VOC emissions from wastewater treatment, Highlands Ethanol is proposing to burn the biogas in the biomass boiler and use a flare as a backup to handle surges in biogas production or to handle full biogas production during periods when the biomass boiler is not available. This is the top level of control and therefore an analysis of economic, energy, and environmental impacts is not required.

Determination of BACT

Highlands Ethanol plans to combust the biogas that is generated by anaerobic digestion; the combustion will occur primarily in the biomass boiler with a flare used for backup purposes. The current top level of BACT control in the industry is 98 percent as shown in Table E-5. Highlands Ethanol has determined that 98 percent control, which is equivalent to the one facility for which control data were available as well as the control level required for new facilities in Indiana, is achievable. Therefore, BACT for VOC emissions from anaerobic digestion is the biomass boiler with a backup flare achieving 98 percent control, which is the top level of control.

5.3.1.6 Cooling Tower

VOC emissions can occur from cooling towers used in chemical plants, where the circulating water is used to cool down hydrocarbon process streams. While the process heat exchangers will be designed to prevent contact of the cooling water with the process streams, leaks in the process heat exchangers can occur. The VOCs that could potentially enter the cooling water would ultimately be stripped out by the cooling tower's air flow into the atmosphere.

The most practical method of controlling VOC emissions is to promptly repair any leaking components. Highlands Ethanol proposes to collect a sample of cooling water on a weekly basis and analyze it for VOCs. This will enable the early detection of leaking heat exchangers, thereby minimizing VOC emissions. Therefore, BACT for process heat exchanger leaks is establishment of a weekly monitoring program.

5.3.1.7 Steam Production, Biomass Boiler

The project is proposing one fluidized bed biomass boiler with a rated capacity of 270 MMBtu/hr that will burn stillage cake, biosolids and biogas as primary fuels with natural gas for backup/supporting fuel. VOCs are formed through incomplete combustion of fuels. The rate of VOC formation is enhanced by low combustion temperatures and near- or sub-stoichiometric quantities of oxygen in the combustion zone. The boiler will implement combustion controls as BACT to minimize VOC emissions.

Available Control Alternatives

The methods for reduction or control of VOC emissions from boilers include:

- Good combustion practice; and
- VOC oxidation catalysts.

Good combustion practice, also known as burner optimization, is usually the first method used to limit formation of VOC (as well as CO and NO_X). Optimization is achieved by modifying boiler-operating conditions, including excess air control, boiler fine tuning and balancing the fuel and air flow to the combustion zone. Unfortunately, the conditions (high excess air) that favor reduced VOC formation also generally result in the increase of NO_X formation. However, current boiler design is capable of minimizing the formation of both VOC and NO_x.

VOC oxidation catalysts can be used to control VOC emissions from boilers. The VOC catalyst promotes the oxidation of VOC to CO_2 and water as the emission stream passes through the catalyst bed. These catalysts are similar or identical to the catalysts used to oxidize CO in emissions from combustion sources. The catalyst is usually made of a precious metal such as platinum, palladium, or rhodium. Other formulations, such as metal oxides for emission streams containing chlorinated compounds, are also used. The oxidation process takes place spontaneously, without the requirement for introducing reactants. The performance of these oxidation catalyst systems is a function of several variables, including temperature, pressure drop, incoming VOC concentration, the types of VOCs in the exhaust, the presence of PM in the flue gas, condensables and certain elements that may foul or deactivate (poison) the catalysts.

The permit database records relating to VOC emissions from biomass boilers are presented in Appendix E, Table E-6. It is important to recognize that Highlands Ethanol proposes to install a fluidized bed biomass boiler and fluidized bed design has implications for the emission controls that are feasible and/or effective. There are four identified facilities in the permit database utilizing the fluidized bed biomass boiler design. The Public Service Company of New Hampshire's (PSNH) Schiller Station operates fluidized bed boilers capable of firing biomass (wood) in addition to coal. The Corn Plus facility discussed in Section 5.3 has a fluidized bed biomass boiler combusting corn syrup. The Nacogdoches Power facility proposed a bubbling fluidized bed boiler burning wood chips and sawdust. The Yellow Pine Energy facility in Georgia has proposed fluidized bed biomass boilers burning wood waste. The Yellow Pine Energy, PSNH, Corn Plus, and Nacogdoches Power facilities all propose or utilize good combustion controls for VOCs.

Oxidation catalyst technology has never been applied to a fluidized bed biomass boiler. Particulate matter emissions from a fluidized bed biomass boiler are significantly higher than from a standard natural gas or distillate oil fired boiler, which is the typical application for an oxidation catalyst. Given the particulate matter loading from the boiler, it is not feasible to install an oxidation catalyst in the location where the temperature is conducive to catalyst operation upstream of the fabric filter. The only way that this technology would be technically feasible would be to install it downstream of the fabric filter. However, due to the cooler flue gas temperature downstream of the fabric filter, this would require installation of a duct burner downstream of the fabric filter and upstream of the oxidation catalyst. A significant amount of fossil fuel would be combusted in the duct burner to reheat the flue gas to the catalyst activation temperature. Good combustion practices are inherent in the design and efficient operation of the fluidized bed boiler.

Ranking of Technically Feasible Controls

Oxidation catalysts are typically considered the top level of control. However, the oxidation catalyst technology has never been applied to a fluidized bed biomass boiler. Particulate matter emissions from a fluidized bed biomass boiler are significantly higher than from a standard natural gas or distillate oil fired boiler, which is the application typical for an oxidation catalyst. Given the particulate matter loading from the boiler, it is not practical to install the oxidation catalyst in the location where the temperature is conducive to catalyst operation upstream of the fabric filter. Therefore, an oxidation catalyst on a fluidized bed biomass boiler is not technically feasible due to the operating temperature requirements and the need to place the catalyst downstream of the particulate controls to avoid plugging of the catalyst. To reheat the flue gas to the required temperature for an oxidation catalyst, over 99,272,000 cubic feet of natural gas per year would be fired in the duct burner, which is a significant energy impact. Firing natural gas in a duct burner would increase emissions of NO_X, SO_2, CO and PM. In addition, a significant amount of GHG emissions (CO_2) would be generated. Estimated emissions from firing the required amount of natural gas in a duct burner are calculated using natural gas combustion emission factors from Section 1.4 of USEPA's AP-42 (USEPA, 1998) as follows:

- VOC 0.3 tpy;
- NO_X 5.0 tpy;
- SO_2 0.03 tpy;
- CO 4.2 tpy;
- PM 0.4 tpy; and
- CO_2 5,956 tpy.

In addition to these issues, other constituents in the flue gas would cause fouling and deactivation of the catalyst bed. The VOC control efficiency from good combustion practices is not readily quantifiable, but combustion parameters such as air to fuel ratio can be monitored to assure optimal combustion conditions for minimizing air emissions. Given these significant energy and environmental impacts, an oxidation catalyst is not considered BACT for controlling VOCs from the biomass boiler. Therefore, good combustion practices represents BACT for the biomass boiler.

Determination of BACT

The top level of control, an oxidation catalyst, was determined to not represent BACT based on its technical feasibility issues as well as energy and secondary environmental impacts. Therefore, Highlands Ethanol proposes to utilize good combustion practices to control VOC emissions from the biomass boiler as BACT.

The proposed VOC BACT emission limit is 0.005 lb/MMBtu on a 24-hour average basis, which as shown in Appendix E, Table E-6, is equivalent to the lowest permitted VOC emission rate identified for fluidized bed biomass boilers at PSNH's Schiller Station in New Hampshire.

5.3.1.8 Steam Production, Peaking Boiler

The project will include a boiler to produce steam during peak demand from the production process areas. The peaking boiler will have a maximum heat input capacity of 95 MMBtu/hr fired solely with natural gas. The boiler will operate at all times during production and will cycle up and down dependent upon process demand. When the biomass boiler is down the peaking boiler can also provide auxiliary steam to the operations.

As discussed in Section 5.3.1.7 above, available VOC control technologies include oxidation catalysts and good combustion practices. The permit database records relating to VOC emissions from natural gas-fired and distillate oil-fired backup and auxiliary boilers are presented in Appendix E, Table E-7. There are 17 facilities in the database relating to such boilers. Eight facilities have no control for VOCs, eight facilities utilize good combustion practices to control VOCs, and one facility utilizes an oxidation catalyst for control of VOCs.

Based upon previously permitted facilities, BACT for VOC emissions from the peaking boiler is good combustion practices. The proposed VOC BACT emission limit is 0.0014 lb/MMBtu while firing natural gas. These proposed emission rates are equivalent to the lowest emission rate shown in Table E-7.

5.3.1.9 Emergency Engines

As discussed in Section 4.0, the fire pump engine and emergency generators will be subject to the NSPS for Stationary Compression Ignition Internal Combustion Engines (40 CFR 60, Subpart IIII). As such, the engines will be required to meet specific emission standards based on engine size, model year, and end use. Use of these engines for testing and maintenance will be limited to 100 hours per year. In addition, they will also be required to use diesel fuel that meets the requirements of 40 CFR 80. This means that the fuel used in these engines must have a maximum sulfur content of 15 ppmw (0.0015 percent) for non-road diesel fuel, which is consistent with the characteristics of ULSD.

As with the other combustion sources, good combustion practice and VOC oxidation catalysts are available control alternatives. The permit database records relating to VOC emissions from emergency diesel engines are presented in Appendix E, Table E-8. There are 16 entries in the database relating to emergency engines (fire pumps or emergency generators). Five of the entries list no control for VOCs; the other 11 entries list engine design or good combustion practices, some in conjunction with low sulfur fuel. None of the entries list add-on controls.

While the oxidation catalyst technology is technically feasible for application to internal combustion engines, it would not be cost effective given the high cost of add-on controls coupled with the extremely low emissions and very limited operating hours.

Good combustion practices are inherent in the design and efficient operation of the units. In addition, in accordance with 40 CFR 60, Subpart IIII, Highlands Ethanol will be required to utilize ULSD in these units and operate them no more 100 hours per year for maintenance and testing. Therefore BACT for these units is good combustion practices, use of ULSD, and operation for maintenance and testing purposes for no more than 100 hours per year. The proposed VOC BACT emission limits are as follows:

- Emergency Generators – 0.64 g/kW·hr; and
- Fire Pump – 0.3 g/hp·hr.

5.3.1.10 Stillage Loadout Fugitive Emissions

Stillage cake will be removed from final distillation and dehydration, sent to dewatering to remove some of the water fraction, and conveyed to the biomass boiler for use as fuel. The stillage will not otherwise be dried. Stillage will be generated at an approximate rate of 32 wet tons per hour and will consist primarily of lignin fibers and secondarily of unhydrolyzed cellulose fibers with moisture content in the range of 50 to 65 percent. Handling will be performed entirely within a closed system except for the conveyor. Based on the consistency and moisture content of the material, PM emissions are expected to be negligible. VOC emissions will occur from the evaporation of trace organics dissolved in the water fraction and therefore maintenance of the material at ambient temperature will reduce the potential for fugitive VOC emissions.

The only control option for this process would be to capture the emissions and vent them to an add-on control device such as a wet scrubber or thermal oxidizer. However, the potential uncontrolled VOC emissions from the process are calculated to be only 2.8 tons per year, which is very low compared to the other VOC emitting sources at the facility. Based on this low emission rate, capturing and controlling these emissions with an add-on control device would clearly not be cost effective. Therefore, BACT is proposed to be maintaining the stillage cake at ambient temperature.

5.3.1.11 Fugitive Equipment Leaks

The permit database records relating to VOC emissions from fugitive equipment leaks are presented in Appendix E, Table E-9. There are 24 facilities in the database relating to equipment leaks. Two of the facilities have no control and two employ best management practices. The other 20 facilities have established leak detection and repair (LDAR) programs for control of VOCs from fugitive equipment leaks. Because of the fugitive nature of this emission source and the sheer numbers of components (pumps, valves, flanges, etc.) in VOC service in an ethanol production facility, it would not be practical or cost effective to capture and control these emissions.

The most practical method of controlling VOC emissions is to promptly repair any leaking components, as evidenced by the database records for this emission source. Highlands Ethanol will be subject to 40 CFR 60, Subpart VVa, the NSPS for VOC Equipment Leaks in the Synthetic Organic Chemical Manufacturing Industry (for projects that commence construction or modifications after November 7, 2006), which requires an LDAR program. Therefore, BACT for equipment leaks is establishment of an LDAR program in compliance with 40 CFR 60, Subpart VVa.

5.3.2 Particulate Matter

As detailed in Table 5-1, the specific sources of PM_{10} and $PM_{2.5}$ emissions at the Highlands Ethanol facility include:

- Miscellaneous Storage Silos;
- Cooling Tower;
- Steam Production;
- Emergency Engines; and
- Fugitive dust from roads.

For many of the project's particulate matter sources, it is estimated that the particulate matter is nearly all $PM_{2.5}$. Consequently for these sources, the BACT limits for PM_{10} and $PM_{2.5}$ will be the same. For those sources with available information regarding the particle size of the emissions, separate BACT limits for PM_{10} and $PM_{2.5}$ are provided. The evaluation of BACT for each of these sources of particulate matter emissions is presented in the following sections.

5.3.2.1 Miscellaneous Storage Silos

The miscellaneous storage silos include the following miscellaneous chemical storage silos and day bins:

- Powdered Cellulose Storage Silo;

- Wheat Bran Storage Silo;
- Ammonium Sulfate Storage Silo;
- Potassium Phosphate Storage Silo;
- Bulk Urea Storage Silo;
- Discrete Wheat Bran Transfers Day Bin;
- Discrete Urea Transfers Day Bin;
- Ash Storage Silo;
- Sand Storage Silo;
- Limestone Storage Silo; and
- Hydrated Lime Storage Silo.

Permit database records relating to $PM_{2.5}/PM_{10}$ emissions from lime handling presented in Table E-10 are representative of dry chemical storage and handling for other materials as well.

Fabric filters are widely accepted to represent the top level of control for particulate matter emission sources. Highlands Ethanol intends to install fabric filters (i.e., bin vent filters) on the miscellaneous storage silos. In addition, transfer points will be enclosed. Because Highlands Ethanol is installing the top level of control, this represents BACT and no further analysis is required.

The emission rates shown in Table E-10 range from 0.022 gr/dscf to 0.0005 gr/dscf. However, the operation associated with the lowest emission rate (0.0005 gr/dscf) at Nucor Corporation in Arkansas is a pelletized lime handling operation, which has lower dust generation potential and is therefore not analogous to Highlands Ethanol's operations. The next lowest emission rate shown in Table E-10 is 0.005 gr/dscf, which is met by five of the 29 operations. Therefore, Highlands Ethanol is proposing a $PM_{2.5}/PM_{10}$ BACT emission limit of 0.005 gr/dscf for the miscellaneous storage silos.

5.3.2.2 Cooling Tower

The permit database records relating to particulate matter emissions from cooling towers are presented in Appendix E, Table E-11. There are 38 cooling tower entries in the database. Six of these cooling towers are either not controlled or the control is not specified. Two are controlled by best management practices. The remaining 30 are controlled by drift eliminators.

Drift eliminators integral to the cooling tower design are the only practical method of control for this source. The permit database shows that the level of drift elimination ranges from 0.001 percent to 0.0005 percent. There are ten facilities with cooling towers meeting 0.0005 percent drift eliminators, three in Arizona (one at Dome Valley Energy Partners and two at Allegheny Energy – La Paz) and two in Florida (at Progress Energy – Crystal River and Progress Energy –

Anclote). Highlands Ethanol plans to install a cooling tower with a 0.0005% drift eliminator, which is better than the two recently permitted ethanol facilities in Florida, Southeast Renewable Fuels (SRF), LLC and Highlands EnviroFuels (HEF), LLC, and represents the top level of control for a renewable fuels facility.

Because Highlands Ethanol is installing the top level of control, this represents BACT and no further analysis is required. The proposed PM_{10} BACT emission limit is cooling tower drift limited to 0.0005 percent of the water recirculation rate.

5.3.2.3 Steam Production, Biomass Boiler

The biomass boiler will be subject to the NSPS for Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60, Subpart Db) as the boiler's maximum firing rate will be 270 MMBtu/hr, greater than the applicability threshold of 100 MMBtu/hr. Therefore filterable PM emissions are limited to 0.030 lb/MMBtu per NSPS Subpart Db.

The permit database records relating to $PM_{2.5}/PM_{10}$ emissions from biomass boilers are presented in Appendix E, Table E-12. There are 36 biomass boiler entries in the database. Seventeen of these biomass boilers are controlled with electrostatic precipitators (ESPs) or a combination of cyclones and ESPs. Ten are controlled with wet scrubbers or a combination of cyclones and wet scrubbers. Nine are controlled by fabric filters.

Technically feasible particulate matter control technologies include fabric filters, ESPs, cyclones and wet scrubbers; typically cyclones are applied in series with another form of control technology. However, from a top-down perspective, the most effective types of particulate matter control equipment being successfully applied to biomass boilers are fabric filters and ESPs. Fabric filters have surpassed ESPs as the preferred particulate control device because they provide better control for finer particulate matter.

Highlands Ethanol will install fabric filters on the biomass boiler, which represents the top level of BACT control and no further analysis is required. The emission rates shown in Table E-12 range from 0.0125 lb/MMBtu to 0.8 lb/MMBtu. Highlands Ethanol is proposing a $PM_{2.5}/PM_{10}$ BACT emission limit of 0.01 lb/MMBtu (filterable, based on Method 5), which is more stringent than any of the units listed in the permit database.

5.3.2.4 Steam Production, Peaking Boiler

The peaking boiler will be subject to the NSPS for Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60, Subpart Dc) because the boiler's maximum firing rate will be 95 MMBtu/hr, which is within the applicability threshold of 10-100 MMBtu/hr. However, there are no PM limits for gas fired boilers under this NSPS.

The permit database records relating to PM_{10} emissions from natural gas-fired boilers are presented in Appendix E, Table E-13. In all cases, the control technology is either no control or use of clean fuels combined with good combustion practices. As discussed in Section 5.3.2.3 above, proven add-on particulate matter control technologies include fabric filters, electrostatic precipitators (ESP), cyclones and wet scrubbers. However, given the fact that the peaking boiler will utilize natural gas as the sole fuel, add-on controls would not be cost effective.

BACT for particulate matter emissions from the peaking boiler will be the use of natural gas as the sole fuel and good combustion practices. The proposed PM_{10} BACT emission limit is 0.004 lb/MMBtu (filterable based on Method 5). This proposed emission rate is equivalent to the most recent determination shown in Table E-13.

5.3.2.5 Emergency Engines

As discussed in Section 4.0, the fire pump engine and emergency generator engines will be subject to NSPS Subpart IIII (Stationary Compression Ignition Internal Combustion Engines). As such, the engines will be required to meet specific emission standards based on engine size, model year, and end use. Use of these engines for testing and maintenance will be limited to 100 hours per year. In addition, they will also be required to use diesel fuel that meets the requirements of 40 CFR 80. This means that the fuel used in these engines must have a maximum sulfur content of 15 ppmw (0.0015 percent) for non-road diesel fuel, which is consistent with the characteristics of ULSD.

The permit database records relating to $PM_{2.5}/PM_{10}$ emissions from emergency diesel engines are presented in Appendix E, Table E-14. There are 20 entries in the database relating to emergency engines (fire pumps or emergency generators). Six of the entries list no control for $PM_{2.5}/PM_{10}$. One entry limits the engine to 200 hours per year. The other 13 entries list engine design or good combustion practices, some in conjunction with low sulfur fuel. None of the entries list add-on controls.

While add-on controls are technically feasible for application to compression-ignition internal combustion engines, it would not be cost effective given the high cost of add-on controls coupled with the extremely low emissions and very limited operating hours of these engines.

Good combustion practices are inherent in the design and efficient operation of the units. In addition, in accordance with 40 CFR 60, Subpart IIII, Highlands Ethanol will be required to utilize ULSD in these units and operate them no more 100 hours per year for maintenance and testing. Therefore BACT for these units is good combustion practices, use of ULSD, and operation for maintenance and testing purposes for no more than 100 hours per year. The proposed $PM_{2.5}/PM_{10}$ BACT emission limits are as follows:

- Emergency Generator – 0.2 g/kW·hr; and
- Fire Pump – 0.15 g/hp·hr.

5.3.2.6 *Fugitive Dust from Roads*

Approximately 60 trucks per day will be used to deliver feedstock directly to the facility and an additional 127 vehicles per day all of which will drive on the plant roads. The only practical measures to control fugitive dust from roads are paving the roads or employing other dust control measures such as wetting, maintaining low vehicle speeds and/or utilizing dust suppressant agents. All roads located at the plant will be paved, which is BACT for this source.

5.3.3 Nitrogen Oxides

Nitrogen oxides (NO_X) are formed as a result of the combustion process through either the oxidation of nitrogen in the fuel (fuel NO_X) or fixation of atmospheric nitrogen (thermal NO_X). As such, NO_X control is primarily accomplished through either the combustion process or post combustion controls.

As detailed in Table 5-1, the specific sources of NO_X emissions at the Highlands Ethanol facility include:

- Steam Production; and
- Emergency Engines.

5.3.3.1 *Steam Production, Biomass Boiler*

<u>Available Control Alternatives</u>

The biomass boiler will be subject to the NSPS for Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60, Subpart Db) as the maximum firing rate will be 270 MMBtu/hr, above the applicability threshold of 100 MMBtu/hr. Therefore NO_X emissions are limited to 0.30 lb/MMBtu for biomass firing per NSPS Subpart Db.

Emission reduction techniques for NO_X encompass both combustion controls and post-combustion controls. In standard solid fuel boiler design, combustion controls include low NO_X burners, flue gas recirculation, and staged combustion/low excess air. However, these techniques are not applicable to the fluidized bed boiler design proposed for the Highlands Ethanol project. Combustion in a fluidized bed unit results in inherently low NO_X emissions compared to other solid-fuel boiler designs by limiting peak combustion temperatures, which results in emission levels similar to a traditional boiler design employing combustion controls. Therefore, the remainder of this analysis considers possible post-combustion NO_X control for the biomass boiler.

The permit database records relating to NO_X emissions from biomass boilers are presented in Appendix E, Table E-15. There are 31 biomass boiler entries in the database. Two of these biomass boilers are controlled with Selective Catalytic Reduction (SCR). Sixteen of the biomass boilers are controlled with Selective Noncatalytic Reduction (SNCR). The remaining

13 biomass boilers are controlled with good combustion design and operation. Therefore, add-on NO_X control technologies evaluated include SCR and SNCR.

SCR uses a combination of reducing reagent and a catalyst placed in the flue gas stream to promote the NO_X reduction reaction. In a full-scale SCR system, the flue gas is ducted through a separate reactor that contains a catalyst. With SCR, ammonia (NH_3), which is used as the reducing agent, is injected into the flue gas upstream of a catalyst reactor that is placed in a location where the gas temperature is between 550°F and 750°F (USEPA, 2002b). The ammonia reacts with NO_X on the catalyst to form nitrogen gas and water. The catalyst is installed in the reactor in layers. Catalysts can be installed with a specified number of catalyst layers with provisions for adding future layers if necessary. While SCR systems have the potential for high NO_X removal, there are inherent operating concerns associated with their use such as plugging or poisoning of the catalyst, high dependence on proper flue gas temperature for NO_X reduction, and some emissions of unreacted ammonia ("ammonia slip").

SNCR uses injection of a NO_X reducing reagent, either anhydrous ammonia (NH_3), aqueous ammonium (NH_4^+), or urea ($NH_2C(O)H_2$), into the flue gas downstream from the combustion zone. The reducing reagent is injected into the flue gas where the exhaust temperature is between 1,600°F and 2,100°F. The high gas temperatures support high chemical reaction rates so that a catalyst is not required. The reagent reduces NO_X to nitrogen and water. SNCR systems often have multiple injection levels to account for shifting of the optimal reaction temperature window (1,600°F - 2,100°F) as the boiler load changes. This arrangement ensures maximum NO_X reduction over varying boiler loads and as the furnace heat exchange characteristics vary. With SNCR, placement of the reagent injection probes is important. If reagent is injected at a point where the temperature is greater than 2,100°F, ammonia or urea will react with oxygen to form additional NO_X. At gas temperatures below 1,600°F, excessive/unreacted ammonia passes through the ductwork and is discharged out the stack as ammonia slip.

SCR has been successfully applied at biomass, coal, oil and natural gas fired boiler facilities in the United States. In some applications, the SCR system can be located within the heat exchanger section upstream of the other air pollution control systems, termed hot-side application. However, this type of application is not feasible for a fluidized bed biomass boiler because of the particulate matter loading prior to the fabric filter. The particulate loading damages the SCR system through erosion, thermal sintering and fly ash deposition. As detailed in a 2005 study for the International Energy Agency on biomass impacts on SCR performance, high levels of alkali aerosols are present in the flue gas from biomass combustion. These alkali aerosols in high concentrations, calcium and potassium in particular, have been shown to irreversibly poison the SCR catalyst and dramatically reduce its performance as documented in this study. Placement of an SCR system after other air pollution control equipment, termed cold side application, is the only technically feasible method of incorporating SCR into the fluidized bed boiler system. Cold side applications require flue gas reheat (i.e., fossil fuel is burned to reheat the flue gas) to raise the gas temperature from approximately 270°F to 650°F, the optimum temperature range for effective NO_X reduction across the catalyst bed. Reheating the gas stream also involves heat recovery that adds capital and operating expenses.

There is a significant amount of experience with SNCR systems in biomass boilers, including fluidized bed biomass boilers, as documented in Table E-15. Therefore, the SNCR technology is technically feasible for implementation on the Highlands Ethanol biomass boiler.

Ranking of Technically Feasible Controls

With respect to the expected level of NO_X control using an SCR system, there are a number of variables that affect system performance, including presence of catalyst fouling contaminants in the gas stream, system operating temperature to optimize catalyst effectiveness, flue gas temperature to prevent condensation of acid gases, and formation of undesirable air contaminants such as ammonium bisulfite and ammonium chloride. NO_X emission reductions ranging from 50 to 90 percent are typical. The two SCR systems shown in Table E-15 have NO_X control efficiencies of 80 percent. SCR represents the top level of control.

NO_X emission reductions with SNCR typically range from 40 to 60 percent. As shown in Table E-15, control efficiencies of the SNCR systems installed on biomass boilers as reported in the permit database range from 48 to 65 percent. This represents the next most stringent level of control.

The only other available control option is good combustion control, which would provide the lowest level of control possible. However, the actual NO_X reduction with this control option is not quantifiable.

Economic, Energy, and Environmental Impacts

As discussed above the top level of control is SCR. The following presents the economic, energy, and secondary environmental impacts associated with installing an SCR system on the biomass boiler at the proposed Highlands Ethanol facility.

Economic Impacts

The analysis of applying SCR to the biomass boiler to control NO_X emissions is provided in Tables 5-2 and 5-3. The cost is derived from a 2005 cost quotation from Riley Power to provide SCR on a 288 MMBtu/hr municipal solid waste boiler. SCR costs are a function of the exhaust gas flow rate. The exhaust gas flow rate of the boiler from the Riley cost quote is 74,188 scfm. The proposed biomass boiler will have an exhaust gas flow rate of 74,264 scfm. The basic equipment cost was scaled to correspond to the size of the Highlands Ethanol biomass boiler using the engineering "six-tenths" rule of economies of scale (Peters et al., 2002) as follows:

$$\text{Cost 2} = \text{Cost 1} \times (\text{Size 2}/\text{Size 1})^{0.6}$$

Costs were then escalated to 2011 dollars using Marshal & Swift Equipment Cost Indices (*Chemical Engineering*, 2008) from third quarter 2005 and fourth quarter 2011. The remainder of the cost information was developed using the cost estimation algorithms provided in the USEPA Office Air Quality Planning and Standards (OAQPS) Air Pollution Control Cost Manual (USEPA, 2002b). As described above, to be technically viable an SCR system needs to be placed on the cold side of the air pollution control train. As such, our cost estimates are based on locating the SCR unit downstream of the fabric filter and upstream of the induced draft fan, which would require flue gas reheating with a duct burner. Supporting calculations for the cost estimation are presented in Appendix E.

As presented in Table 5-2 the total capital investment cost for an SCR system is estimated to be approximately $16,200,000. Table 5-3 presents the estimated annual operating cost of approximately $3,700,000. Based on these costs the cost effectiveness value associated with using SCR would be $23,500 per ton of NO_X removed. This value is not considered to be cost effective. The high economic impact of applying SCR to the biomass boiler would eliminate the control technology from further consider as BACT.

Energy Impacts

The annual energy impacts resulting from using an SCR system would be the use of over 99,272,000 additional cubic feet of natural gas to re-heat the flue gas and 778,000 kWh per year of electricity to overcome the increased pressure drop across the catalyst reactor. The energy impact from natural gas consumption would be 629,500 cubic feet of natural gas per ton of NO_X controlled. The impact associated with electricity consumption would be 4,933 kWh per ton of NO_X controlled. These values represent significant energy impacts and would be considered excessive given the level of NO_X emissions controlled. These energy impacts, aside from the high economic impact, eliminate SCR from further consideration as BACT.

Environmental Impacts

The environmental impacts associated with using SCR are not inconsequential. These impacts result primarily from the combustion of additional fossil fuel to reheat the flue gas. Firing natural gas in a duct burner would not only increase NO_X emissions, the pollutant intended to be controlled by the SCR system, but would also increase CO, VOC, SO_2, and PM emissions. In addition, a significant amount of greenhouse gas emissions (CO_2) would be generated. Estimated emissions from firing the required amount of natural gas were calculated using natural gas combustion emission factors from Section 1.4 of USEPA's AP-42 (USEPA, 1998) as follows:

- VOC 0.3 tpy;
- NO_X 5.0 tpy;
- SO_2 0.03 tpy;

- CO 4.2 tpy;
- PM 0.4 tpy; and
- CO_2 5,596 tpy.

The increase in emissions represents a significant environmental impact. Additionally, an SCR system would generate a solid waste stream in the form of spent catalyst that would also have a negative environmental impact.

Table 5-2

Economic Analysis of SCR for Biomass Boilers - Capital Costs

Source Parameters		
Combustion source		Fluidized Bed Biomass Boiler
Heat Input (MMBtu/hr)		270
SCR location		Tail-end after baghouse
Uncontrolled NOx Emission Rate (tpy)		197.1
Uncontrolled NOx concentration (lb/MMBtu)		0.167
SCR NOx Control Efficiency		80%
Heat recovery		60%
Operating schedule (hr/yr)		8,760
Actual flow rate (acfm)		107,598
Standard Flow rate (scfm)		74,264
Standard Flow Rate for Boiler from Riley Power Cost Qote (scfm)		74,188
Inlet temperature (°F)		305
SCR temperature ((°F)		650
Ammonia Slip (assumed) (ppm)		2
Cost escalation factor (3rd Qtr 2005 - 4th Qtr 2011)		1.267
Item	**Factor**	**Cost**
Equipment Costs		
Complete System SCR Equipment Cost	Based on Cost Quote from Riley Power(1)	$6,500,000
Auxiliary Equipment	All is included in Riler Power quote	$0
Cost Escalation to 2011 Dollars	Reference (2)	$1,700,000
Purchased Equipment Cost		$8,200,000
Sales Taxes	0.03 x Purchased Equipment Cost (3)	$246,000
Freight	0.05 x Purchased Equipment Cost (3)	$410,000
Total Equipment Cost		$8,856,000
Direct Installation Costs		
Foundation	0.08 x Total Equipment Cost (3)	$708,500
Erection and Handling	0.14 x Total Equipment Cost (3)	$1,239,800
Electrical	0.04 x Total Equipment Cost (3)	$354,200
Piping	0.02 x Total Equipment Cost (3)	$177,100
Insulation	0.01 x Total Equipment Cost (3)	$88,600
Painting	0.01 x Total Equipment Cost (3)	$88,600
Total Direct Installation Costs		$2,656,800
Direct Capital Cost	Total Equipment Cost + Direct Installation Costs	$11,512,800
Indirect Installation Costs		
General Facilities	0.05 x Direct Capital Cost (3)	$575,600
Engineering and Home Office Fees	0.1 x Direct Capital Cost (3)	$1,151,300
Process Contingency	0.05 x Direct Capital Cost (3)	$575,600
Total Indirect Installation Costs		$2,302,500
Total Direct Capital and Indirect Installed Costs		$13,815,300
Project Contingencies	0.15 of Total Direct and Indirect (3)	$2,072,300
Total Plant Costs		$15,887,600
Preproduction costs	0.02 of Total Plant Costs (3)	$317,800
Inventory Capital	Initial ammonia charge (assumes 1 week supply) (3)	$4,400
Total Capital Investment (TCI)		$16,209,800

Reference Sources:

(1) 2005 cost quote from Riley Power for a 288 MMBtu/hr boiler with a flow rate of 74,188 scfm scaled to proposed boiler of 400 MMBtu with a flow rate of 110,020 scfm using engineering "Six-Tenth's Rule"

Highlands Ethanol Cost = Quoted Cost ($6,500,000) x (110,020/74,198)^0.6 = $8,200,000

(2) Marshal & Swift Equipment Cost Index: 3rd Qtr 2005 = 1260.9; 4th Qtr 2011 = 1597.7; ratio = 1597.7/1260.9 = 1.267

(3) U.S. EPA 2002. EPA Air Pollution Control Cost Manual, 6th Ed., Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, EPA/452/B-02-001, January, 2002

Table 5-3				
Economic Analysis of SCR for Biomass Boilers - Annual Costs				
Source Parameters				
Combustion source				Fluidized Bed Biomass Boiler
Heat Input (MMBtu/hr)				270
SCR location				Tail-end after baghouse
Uncontrolled NOx Emission Rate (tpy)				197.1
Uncontrolled NOx concentration (lb/MMBtu)				0.17
SCR NOx Control Efficiency				80%
Heat recovery				60%
Operating schedule (hr/yr)				8,760
Actual flow rate (acfm)				107,598
Standard Flow rate (scfm)				74,264
Inltet temperature (°F)				305
SCR temperature ((°F)				650
Ammonia Slip (assumed) (ppm)				2
Cost escalation factor (3rd Qtr 2005 - 2nd Qtr 2008)				1.267
Cost Item	**Cost Factor**	**Unit Cost**		**Total Cost**
Direct Annual Costs				
Maintenance	OAQPS Section 4, Chapter 2 SCR Costing (1)	0.015 of TCI		$243,100
Replacement Parts				
Catalyst Volume	OAQPS Section 4, Chapter 2 SCR Costing (1)	1216	cu. ft.	
Estimated Catalyst Area	OAQPS Section 4, Chapter 2 SCR Costing (1)	112	sq. ft.	
Estimated Number of Catalyst Layers	OAQPS Section 4, Chapter 2 SCR Costing (1)	3		
Catalyst Life	Two year catalyst life (2)	2	yrs	
Catalyst Cost	Reference (2), escalated to 2008	$167	/cu. ft.	
Catalyst Replacement Cost				$101,700
Reagent Comsumption (19% aqueous ammonia)	OAQPS Section 4, Chapter 2 SCR Costing (1)	92	lb/hr	
Aqueous ammonia costs	19.2% aqueous ammonia delivered (4)	$575.00	/ton	$231,800
Utilities				
BTU Reheat Requirement	Heat Balance	99,272	MMBtu/yr	
Heat Contribution of Waste Stream	Assume zero	0	MMBtu/yr	
Net BTU Reheat Requirement		99,272	MMBtu/yr	
Natural Gas Requirement	1,000 Btu/cu.ft (natural gas)	99,272,000	cu. ft./yr	
Natural Gas Cost	$13.19/1,000 cu. Ft (5)	$8.71	/1000 cu ft	$864,700
Electricity Requirement	OAQPS Section 4, Chapter 2 SCR Costing (1)	778,000	kWhr/yr	
Electricity Cost	$0.10/kWhr (5)	$0.10	/kWhr	$81,300
Indirect Annual Cost				
Administrative Charges	2% TCI (1)	NA		$324,200
Property Taxes	1% TCI (1)	NA		$162,100
Insurance	1% TCI (1)	NA		$162,100
Equipment Life	NA	20	yrs	
Interest Rate	NA	7%		
Capital Recovery Factor	NA	0.094		
Capital Recovery	CRF x TCI			$1,530,100
Total Annual Cost				$3,701,100
Uncontrolled NOx Emission Rate (tpy)				197.1
NOx Controlled (tpy)				157.7
NOx Emitted (tpy)				39.4
Cost Effectiveness ($/ton controlled)				**$23,500**
Reference Sources:				
(1) U.S. EPA 2002. EPA Air Pollution Control Cost Manual, 6th Ed., Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, EPA/452/B-02-001, January, 2002				
(2) Communication with Rich Abrams of Babcock Power Environmental Inc. on January 11, 2005, supplier of SCR systems.				
(3) Communication with John Bowman of Babcock Power Environmental Inc. on August 22, 2008, supplier of SCR systems.				
(4) Ammonia pricing information from ICIS.com 11/25/08				
(5) Local energy costs for Florida from the U.S. Energy Information Administration (Industrial 3-year average 2009-2011)				

Determination of BACT

Given the excessive economic, energy, and environmental impacts associated with application of SCR, it was eliminated from consideration as BACT. The next most stringent control technology available is SNCR. Because the top level of control was eliminated as BACT, the next most stringent level of control, SNCR, has been determined to be BACT. Therefore, Highlands Ethanol proposes to install SNCR to control NO_X emissions from the biomass boiler.

The NO_X emission limits associated with the SNCR systems in the permit database shown in Table E-15 range from 0.075 lb/MMBtu to 0.25 lb/MMBtu. The original permit for the project was issued at 0.075 lb/MMBtu based upon the lowest permitted emission rate for the PSNH Schiller Station wood fired boiler. However, the PSNH boiler fires clean wood and this emission rate has never been demonstrated for a biomass boiler firing stillage, biosolids and biogas from an ethanol renewable fuels facility. The Southeast Renewable Fuels project was approved by the FDEP with an emission rate of 0.08 lb/MMBtu on a 30-day rolling average for a fluidized bed boiler in December 2010. This is the lowest NO_X emission rate approved for a biomass boiler firing biomass from an ethanol renewable fuels facility and it is for the same boiler technology, fluidized bed, which will be employed by the Highlands Ethanol project. Therefore, the proposed NO_X BACT emission rate is 0.08 lb/MMBtu on a 30-day rolling average basis, which is equivalent to the lowest permitted emission rate for a similar boiler technology. Additionally, the proposed NO_X BACT emission rate of 0.08 lb/MMBtu is equivalent to that specified by Congress in Section 1703(d) of the Energy Policy Act of 2005 for renewable fuels projects qualifying for financing from the US Department of Energy.

5.3.3.2 Steam Production, Peaking Boiler

Available Control Alternatives

The peaking boiler will be subject to the NSPS for Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60, Subpart Db) because the boiler's maximum firing rate will be between 10-100 MMBtu/hr. However, NSPS Subpart Dc does not impose NO_X limits on subject boilers.

As discussed in Section 5.3.3.1, emission reduction techniques for NO_X encompass both combustion controls and post-combustion controls. Unlike the biomass boiler, which has a unique design, the peaking boiler will be a standard package boiler design. Consequently, combustion controls are an available option and Highlands Ethanol proposes to install a peaking boiler with low NO_X burners and flue gas recirculation (FGR), which is the highest level of combustion control available.

The permit database records relating to NO_X emissions from backup and auxiliary boilers are presented in Appendix E, Table E-16. There are fifteen entries in the database that were listed in permit records as natural gas fired boilers rated less than 100 MMBtu/hr. Four of these boilers do not have their control type listed. The remainder are controlled with low NO_X burners, four in conjunction with FGR, four with ultra low NOx burners.

Proven add-on NO_X control technologies include SCR and SNCR. However, given the fact that the peaking boiler will utilize clean fuels and will have low emissions, add-on controls would not be cost effective. Therefore, the base level of control for the peaking boiler, low NO_X burners with FGR, is determined to be BACT.

The emission rates in the permit database for natural gas fired boilers rated less than 100 MMBtu/hr, as shown in Table E-16, range from 0.011 lb/MMBtu to 0.05 lb/MMBtu for natural gas firing. The proposed NO_X BACT emission limit is 0.035 lb/MMBtu, which is consistent with the previously approved larger backup boiler for the project and less than the three most recent PSD BACT determinations in the RBLC.

5.3.3.3 Emergency Engines

As discussed in Section 4.0, the fire pump engine and emergency generators will be subject to the NSPS for Stationary Compression Ignition Internal Combustion Engines (40 CFR 60, Subpart IIII). As such, the engines will be required to meet specific emission standards based on engine size, model year, and end use. Use of these engines for testing and maintenance will be limited to 100 hours per year. In addition, they will also be required to use diesel fuel that meets the requirements of 40 CFR 80. This means that the fuel used in these engines must have a maximum sulfur content of 15 ppmw (0.0015 percent) for non-road diesel fuel, which is consistent with the characteristics of ULSD.

The permit database records relating to NO_X emissions from emergency diesel engines are presented in Appendix E, Table E-17. There are 21 entries in the database relating to NO_X emissions from emergency engines (fire pumps or generators). Five of the entries list no control for NO_X. The others entries list good combustion practices and low sulfur fuel. Three entries list engine ignition timing retard, some in combination with good combustion practices and/or low sulfur fuel. None of the entries list add-on controls.

While add-on controls would be technically feasible for application to internal combustion engines, it would not be cost effective given the high cost of add-on controls coupled with the extremely low emissions and very limited operating hours.

Highlands Ethanol proposes to utilize ULSD in these units. These units will be new units and will be required to meet the NSPS for internal combustion engines (40 CFR 60, Subpart IIII) as well. Therefore BACT for NO_X emissions from these units is good combustion practices, use of ULSD, and operation for no more than 100 hours per year for maintenance and testing. The proposed NO_X BACT emission limits are as follows:

- Emergency Generator – 5.76 g/kW·hr; and
- Fire Pump – 2.7 g/hp·hr.

5.3.4 Sulfur Dioxide

Sulfur dioxide (SO_2) emissions result from the oxidation of sulfur bearing compounds in the fuel. SO_2 emissions can be controlled by pre-combustion, combustion or post-combustion controls.

As detailed in Table 5-1, the specific sources of SO_2 emissions at the Highlands Ethanol facility include:

- Steam Production;
- Biomass Backup Flare; and
- Emergency Engines.

5.3.4.1 Steam Production, Biomass Boiler

Available Control Alternatives

Control strategies for SO_2 emissions include pre-combustion controls, combustion zone controls, and post-combustion controls. Pre-combustion control strategies involve the use of low sulfur fuels and fuel sulfur scrubbing. Combustion zone control is achieved by sorbent (e.g., limestone) injection into the fluidized bed. Post-combustion controls comprise wet or dry flue gas scrubbing processes (e.g., spray dryer absorbers).

The permit database records relating to SO_2 emissions from biomass boilers are presented in Appendix E, Table E-18. There are 17 biomass boiler entries in the database relating to SO_2 emissions. Four of these boilers have no control. Three are controlled with dry scrubbers (spray dryer absorbers) and four are controlled with lime or sodium bicarbonate injection. Two list either spray dryer absorber or sodium bicarbonate injection. One lists inherent scrubbing from calcium in the fuel. The remaining three have fuel sulfur limitations.

With sorbent injection, dry sorbent is injected into the fluidized bed to react with acid gases in the flue gas. The reacted calcium salts and unused dry sorbent are then captured in the downstream particulate matter control device. Dry sorbents used are typically limestone or hydrated lime.

Wet scrubbers for acid gas control use an alkaline liquid, typically either caustic soda solution or lime slurry to scrub the flue gases. In larger systems, the use of lime slurry is common for economic reasons. Lime slurry systems react with SO_2 and other acid gases to form calcium based salts which require clarifying, thickening, and vacuum filtering to avoid a concentration build-up of precipitated salts in the system. Sodium-based systems produce a liquid waste with highly soluble sodium-based salts which may require the use of large, carefully contained, holding pond(s) or wastewater treatment plants.

With spray dryer absorbers (also referred to as dry scrubbers, spray dryers, or semi-dry scrubbers), flue gases from the boiler are introduced into an absorbing chamber where the gases are contacted by atomized lime slurry. To form the lime slurry, lime is hydrated by slaking with water. The slurry and any additional cooling water which may be required are pumped to nozzles or a rotary atomizer inside the scrubber's absorbing chamber. Acid gases are absorbed by the slurry mixture and the alkaline component reacts with the gases to form salts. Evaporation of the water produces a finely divided particle of mixed salt and unreacted alkali and results in the flue gas having a lower temperature. A portion of the dry powder drops to the bottom of the scrubber vessel while the flue gases, containing the remaining powder with reacted acid gas salts and the particulates generated during combustion, are delivered to the particulate collection device (e.g., fabric filter) for removal.

Technically Feasible Controls

The boiler is designed to burn stillage cake, biosolids and biogas as its primary fuels. The sulfur content of the stillage cake, biosolids and biogas will be a function of the raw materials that are input to the process (energy cane and energy grasses) and the hydrolysis process which uses sulfuric acid. The sulfur content of these fuels will be variable and cannot be controlled. Therefore, use of low sulfur fuel is not technically feasible. The available SO_2 emissions control methods that are technically feasible are combustion zone controls (limestone injection), post-combustion controls (wet scrubber or spray dryer absorber) and pre-combustion removal of the sulfur in the biogas.

Spray dryer absorbers or wet scrubbers are typically understood to provide the highest level of SO_2 control possible in boiler applications. With the fluidized bed design, however, limestone injection can provide SO_2 controls equivalent to that of spray dryer absorbers or wet scrubbers. Therefore, all three technologies are considered equivalent in this application and represent the top level of control. Because the top level of control will be selected, an analysis of the economic, energy and environmental impacts of other emission reduction technologies is not required. The top controls are sufficient to control sulfur emissions to BACT levels for stillage, biosolids and biogas combustion, and therefore pre-combustion control of sulfur in biogas, which would not reduce sulfur in the stillage or biosolids, would be redundant and not cost effective. Therefore, only the combustion zone and post-combustion technologies discussed above are further considered.

Determination of BACT

Highlands Ethanol plans to utilize limestone injection for the biomass boiler, which is the top level of control, and therefore represents BACT. The SO_2 emission rates in the permit database for biomass boilers, as shown in Table E-18, range from 0.02 lb/MMBtu to 1.54 lb/MMBtu. For this project, the hydrolysis process results in additional sulfur in the fuel and therefore, slightly higher SO_2 emissions. Taking this into account, Highlands Ethanol proposes an SO_2 BACT emission limit of 0.06 lb/MMBtu based on a 30-day rolling average. This limit is consistent with the level of control for the Highlands EnviroFuels (HEF), LLC and Southeast Renewable Fuels, LLC facilities that were recently approved by the FDEP. Because of the potential for variability in short-term levels of sulfur in the fuels, Highlands Ethanol further proposes SO_2 BACT emission limits of 0.12 lb/MMBtu (24-hour rolling average) and 0.14 lb/MMBtu (3-hour block average).

AMEC notes that a dry scrubber will also be installed, primarily for the control of HCl emissions. This design is consistent with that currently permitted for the previously proposed biomass boilers and as such the BACT emission limits shown above for SO_2 are consistent with the existing permit limits. With respect to HCl emissions, the existing permit required the use of CEMS to demonstrate compliance with the HCl emission limits. Because the currently proposed biomass boiler capacity is less than that in the existing permit, potential HCl emissions are now less than that currently permitted. As such, Highlands Ethanol is requesting that the requirement for HCl CEMS be eliminated.

Instead, Highlands Ethanol proposes to use the SO_2 CEMS as a surrogate to demonstrate compliance with the HCl emission limit for the biomass boiler. This proposal is consistent with EPA's recently proposed revision to the Portland Cement NESHAP (Subpart LLL) published in the Federal Register on July 18, 2012. In the revision to the Portland Cement NESHAP, EPA has proposed that facilities equipped with either a wet or dry scrubber to control SO_2 emissions to use an SO_2 CEMS for HCl compliance monitoring. As noted in the preamble to the July 18, 2012, proposed rule revision, "*pilot-scale tests by the EPA at its Multipollutant Control Research Facility support the use of the more easily measured SO_2 as a surrogate for HCl where either wet or dry scrubbers are used*".

In accordance with the proposed July 18, 2012 rule revision, the facility will conduct an initial performance test for HCl and establish an SO_2 operating limit equal to the highest 1-hour average recorded during the HCl performance test. This highest measured 1-hour average SO_2 concentration recorded during the HCl performance test would then serve as the surrogate HCl limit. Deviation from the established SO_2 surrogate limit would trigger a requirement to retest for HCl to re-verify compliance.

5.3.4.2 Steam Production, Peaking Boiler

The most stringent level of control for SO_2 emissions is the firing of natural gas as the sole fuel. Natural gas will be the sole fuel fired in the peaking boiler and will have a SO_2 BACT emission limit of 0.0056 lb/MMBtu, based on FDEP's presumed sulfur content of natural gas of 0.02 gr/scf.

5.3.4.3 Biogas Backup Flare

<u>Available Control Alternatives</u>

During periods when the biomass boiler is unavailable and/or the biogas flow rate exceeds the biomass boiler capacity, the biogas will be combusted in a backup flare. Control strategies for SO_2 emissions from a flare are limited to biogas desulfurization, which can be achieved through a wide range of technologies. The recently permitted Okeechobee Landfill Gas to Energy

Project in Okeechobee, Florida, was required to install either a LO-CAT® or Paques/THIOPAQ® gas desulfuring system to remove sulfur prior to being combusted either in combustion turbines or flares. Alternative control technology includes a standard packed bed wet scrubber with chemical addition for sulfur removal. The Okeechobee Landfill Gas to Energy Project is the only project of comparable size and sulfur content to the biogas produced by the Highlands Ethanol project that was identified and therefore serves as the sole reference for SO_2 BACT for the flare.

Technically Feasible Controls

The application of biogas desulfurization prior to combustion in the backup flare is technically feasible and constitutes the top level of control. The Okeechobee Landfill Gas to Energy Project required a minimum sulfur removal efficiency of 98%, which constitutes the highest level of control. Highlands Ethanol is proposing to install a packed bed wet scrubber with chemical addition for sulfur removal, which is equivalent to the top level of control. Therefore, an analysis of economic, energy, and environmental impacts is not required.

Determination of BACT

Highlands Ethanol has determined that 98 percent sulfur removal is achievable with a packed bed wet scrubber with chemical addition. This is equivalent to the level of control for the Okeechobee Landfill Gas to Energy Project recently approved by the FDEP and presumed to satisfy BACT. Therefore, BACT for SO_2 emissions for the biogas backup flare is 98 percent sulfur removal via a packed bed wet scrubber with chemical addition.

5.3.4.4 Emergency Engines

As discussed in Section 4.0, the fire pump engine and emergency generators will be subject to the NSPS for Stationary Compression Ignition Internal Combustion Engines (40 CFR 60, Subpart IIII). As such, the engines will be required to meet specific emission standards based on engine size, model year, and end use. Use of these engines for testing and maintenance will be limited to 100 hours per year. In addition, they will also be required to use diesel fuel that meets the requirements of 40 CFR 80. This means that the fuel used in these engines must have a maximum sulfur content of 15 ppmw (0.0015 percent) for non-road diesel fuel, which is consistent with the characteristics of ULSD.

SO_2 emissions are a function of the sulfur content in the fuel rather than any other combustion variables. The only practical control technique available for emergency engines that will operate no more than 100 hours per year for testing and maintenance is the use of low sulfur fuels. The permit database records relating to SO_2 emissions from emergency engines are presented in Appendix E, Table E-19. In all cases, the control technology is either no control or use of low sulfur fuels.

Highlands Ethanol proposes to utilize ULSD in these units. These units will be new units and will be required to meet the NSPS for internal combustion engines (40 CFR 60, Subpart IIII) as well. Therefore BACT for SO_2 emissions from these units is good combustion practices, use of ULSD, and operation for no more than 100 hours per year for maintenance and testing.

5.3.5 Carbon Monoxide

Carbon monoxide (CO) is produced by the incomplete oxidation of the fuel. CO emissions can be controlled by combustion or post-combustion controls.

As detailed in Table 5-1, the specific sources of CO emissions at the Highlands Ethanol facility include:

- Steam Production; and
- Emergency Engines.

5.3.5.1 Steam Production, Biomass Boiler

Available Control Alternatives

The following methods for reduction or control of CO emissions from boilers were identified:

- Good combustion practice; and
- CO oxidation catalysts.

Good combustion practice, also known as burner optimization, is usually the first method used to control formation of CO (as well as VOC and NO_X) and was discussed in Section 5.3.1.8. CO oxidation catalysts promote the oxidation of CO to CO_2 and water as the emission stream passes through the catalyst bed. These catalysts are similar or identical to the catalysts used to oxidize VOCs in emissions from stationary sources as discussed in Section 5.3.1.8.

The permit database records relating to CO emissions from biomass boilers are presented in Appendix E, Table E-20. Four of the boilers listed in the database have no controls. Three are controlled by oxidation catalysts and the remainder are controlled by good combustion practices.

Technically Feasible Controls

Oxidation catalysts are typically considered the top level of control. However, oxidation catalyst technology has never been applied to a fluidized bed biomass boiler. Particulate matter emissions from a fluidized bed biomass boiler are significantly higher than from a standard natural gas or distillate oil fired boiler, which is the application typical for an oxidation catalyst. Given the particulate matter loading from the boiler, it is not practical to install the oxidation catalyst in the location where the temperature is conducive to catalyst operation upstream of the fabric filter. In addition to these impacts, other constituents in the flue gas would cause fouling and deactivation of the catalyst bed.

Therefore, an oxidation catalyst on a fluidized bed biomass boiler is not technically feasible due to the operating temperature requirements and the need to place the catalyst downstream of the particulate controls to avoid plugging of the catalyst. To reheat the flue gas to the required temperature for an oxidation catalyst, 99,272,000 cubic feet of natural gas per year would be fired in the duct burner, which is a significant energy impact. Firing natural gas in a duct burner would not only increase CO emissions, the pollutant intended to be controlled by the oxidation catalyst, but would also increase NO_X, SO_2, VOC, and PM emissions. In addition, a significant amount of GHG emissions (CO_2) would be generated. Estimated emissions from firing the required amount of natural gas are calculated using natural gas combustion emission factors from Section 1.4 of USEPA's AP-42 (USEPA, 1998) as follows:

- VOC 0.3 tpy;
- NO_X 5.0 tpy;
- SO_2 0.03 tpy;
- CO 4.2 tpy;
- PM 0.4 tpy; and
- CO_2 5,956 tpy.

The CO control efficiency from good combustion practices is not readily quantifiable, but combustion parameters, such as air to fuel ratio can be monitored to assure optimal combustion conditions for minimizing air emissions. Given these significant energy, and environmental impacts, an oxidation catalyst would not be considered BACT for controlling CO from the biomass boiler. Therefore, good combustion practices represents BACT for the Highlands Ethanol Project.

Determination of BACT

The top level of control, an oxidation catalyst, was determined to not represent BACT as it is technically infeasible and would cause excessive energy and environmental impacts. Therefore, Highlands Ethanol plans to utilize good combustion practices to control CO emissions from the biomass boiler, which is the next most stringent level of control, and therefore represents BACT.

The proposed CO BACT emission limit is 0.1 lb/MMBtu (30-day rolling), which is the lowest emission limit shown in Table E-20. This limit is consistent with the level of control for the Southeast Renewable Fuels, LLC facility that was recently approved by the FDEP.

5.3.5.2 Steam Production, Peaking Boiler

The permit database records relating to CO emissions from natural gas-fired boilers are presented in Appendix E, Table E-21. There are 11 facilities in the database relating to natural gas-fired boilers rated between 10-100 MMBtu/hr. Eight do not have a control method listed for CO, and three facilities utilize good combustion practices to control CO.

Given the fact that the peaking boiler will utilize clean fuels and have low emissions, add-on controls would not be cost effective. Therefore, BACT for CO emissions from the backup boiler is good combustion practices.

The CO emission rates in the permit database for natural gas-fired boilers rated between 10-100 MMBtu/hr, as shown in Table E-21, range from 0.02 lb/MMBtu to 0.08 lb/MMBtu. Highlands Ethanol proposes a CO BACT emission limit of 0.037 lb/MMBtu for natural gas firing. This proposed emission rate is consistent with the previously approved larger backup boiler for the project and well below the BACT emission level recently approved by the FDEP for the FPL West County Energy Center auxiliary boiler.

5.3.5.3 Emergency Engines

As discussed in Section 4.0, the fire pump engine and emergency generators will be subject to the NSPS for Stationary Compression Ignition Internal Combustion Engines (40 CFR 60, Subpart IIII). As such, the engines will be required to meet specific emission standards based on engine size, model year, and end use. Use of these engines for testing and maintenance will be limited to 100 hours per year. In addition, they will also be required to use diesel fuel that meets the requirements of 40 CFR 80. This means that the fuel used in these engines must have a maximum sulfur content of 15 ppmw (0.0015 percent) for non-road diesel fuel, which is consistent with the characteristics of ULSD.

As with the other combustion sources, good combustion practice and CO oxidation catalysts are available control alternatives. The permit database records relating to CO emissions from emergency diesel engines are presented in Appendix E, Table E-22. There are 22 entries in the database relating to emergency engines (fire pumps or generators). Six of the entries list no control for CO and the other entries list engine design or good combustion practices, some in conjunction with low sulfur fuel and limiting operating hours. None of the entries list add-on controls.

While the oxidation catalyst technology is technically feasible for application to internal combustion engines, it would not be cost effective given the high cost of add-on controls coupled with the low emissions and very limited operating hours.

Good combustion practices are inherent in the design and efficient operation of the unit. In addition, Highlands Ethanol proposes to utilize ULSD in these units. Therefore BACT for these units is good combustion practices, use of ULSD, and operation for no more than 100 hours per year for testing and maintenance. The proposed CO BACT emission limits are as follows:

- Emergency Generator – 3.5 g/kW·hr; and
- Fire Pump – 2.6 g/hp·hr.

5.3.6 Greenhouse Gases (GHGs)

GHGs are emitted from the project through combustion and fermentation. The vast majority of the GHGs are comprised of CO_2 with other GHGs (N_2O, CH_4, etc.) emitted in much smaller amounts. As detailed in Table 5-1, the specific sources of GHG emissions at the Highlands Ethanol facility include:

- Fermentation;
- Steam Production;
- Biogas Backup Flare; and
- Emergency Engines.

A GHG BACT analysis must be performed using the "top down" procedures applied for criteria pollutant emissions. Per EPA's 2012 GHG BACT guidance, "top-down" GHG BACT analysis must address carbon capture and storage/sequestration (CCS) for each GHG BACT subject source, as the EPA has determined that CCS is an "available" technology. However, in EPA's *Guidance for Determining Best Available Control Technology for Reducing Carbon Dioxide Emissions from Bioenergy Production* (USEPA 2011b), they note that "*since the use of add-on controls to reduce GHG emissions is not as well advanced as it is for most combustion derived pollutants, in many instances energy efficient measures may serve as the foundation for a BACT analysis for GHGs*". Furthermore, although EPA has deemed CCS an "available" technology, this technology has never been commercially implemented. At this time, there are no commercial carbon sequestration facilities in Florida or the southeast US and therefore, if carbon capture were implemented for the project there would be no place to store it. Accordingly, CCS was determined to be not commercially available and therefore not considered further in this GHG BACT analysis.

Provided in Table E-23 is a summary of all GHG (as CO_2 equivalent) BACT determinations identified in the RBLC as well as the BACT requirements for the Abengoa Bioenergy Biomass of Kansas, LLC project that was issued its final permit on September 16, 2011. As summarized in this table, all identified projects subject to GHG BACT have implemented energy efficiency measures and good combustion practices to satisfy BACT.

5.3.6.1 Fermentation

During the fermentation process, sugars are converted to ethanol and CO_2, which is an inherent part of the Highlands Ethanol project. There are no process modifications or alternatives that can reduce the generation of CO_2 during fermentation other than the maintenance of healthy micro organism colonies in the fermentation vessels that are more efficient at producing ethanol, thereby reducing CO_2 production. Therefore, the technically feasible control technologies available for the direct emissions of CO_2 from fermentation are good fermentation practices and CCS, but as described above, CCS is not yet commercially available.

Secondary GHG emissions can be reduced through energy efficiency measures, water recycling, and beneficial use of co-products. The primary co-products will be stillage cake, biosolids and biogas, which will be fired in the biomass boiler to recover this energy in the form of process steam and electricity. Efficient operation of the biomass boiler and production of process steam and electricity will reduce the need for supplemental fossil fuel requirements and limit overall GHG emissions.

The reduction of primary GHG emissions through the use of good fermentation practices and the reduction of secondary GHG emissions through the application of energy efficiency measures, water recycling and beneficial use of co-products were determined to be BACT for the fermentation process.

5.3.6.2 Steam Production, Biomass Boiler

The biomass boiler will primarily burn biomass in the form of stillage cake, biosolids and biogas as well natural gas as backup/support fuel. The boiler will supply baseload process steam to the facility and up to 7.6 MW of power. Good combustion practices will be used to satisfy BACT requirements for CO and VOC emissions. Stillage cake, biosolids and biogas are biogenic fuels and are low-carbon to carbon neutral fuels. Natural gas will be fired as a supplement to these fuels when necessary to meet process demands; natural gas is the lowest carbon emitting fossil fuel. In EPA's March 2011 guidance, they note that when a proposed facility "*can demonstrate that utilizing a particular type of biogenic fuel is fundamental to the primary purpose of the project, then at the first step of the top-down process, permitting authorities can rely on that to determine that use of another fuel would redefine the proposed source*". The firing of stillage cake, biosolids and biogas is fundamental to the primary purpose of the Highlands Ethanol project. EPA's March 2011 guidance also states that "*permitting authorities might determine in the GHG component of the BACT analysis…that such utilization of biogenic fuels is inherently BACT for GHGs.*"

In accordance with EPA's guidance, BACT for the biomass boiler is the firing of stillage cake, biosolids and biogas as the primary fuels with supplementation via natural gas. The boiler will be operated as a cogeneration unit, providing both steam and electricity to the process, which is the most efficient form of thermal energy use. The boiler will meet BACT for good combustion practices for CO and VOCs, which also satisfies GHG BACT for several recently approved projects as summarized in Table E-23.

5.3.6.3 Steam Production, Peaking Boiler

The peaking boiler will operate only to provide process steam needs that cannot be met by the biomass boiler or auxiliary steam when the biomass boiler is down. The necessity of the peaking boiler is driven by the predicted swings in steam demand during operations and to a lesser extent the lack of sufficient biogenic fuel to operate the production process at all times and therefore, this boiler is inherently necessary for the project. Biogenic fuel (either biogas or biomass) cannot be recovered at a higher rate for a variety of reasons. From a technical perspective, the biomass fuel partially represents feedstock that was not, but could have been, converted into ethanol. Future advances in conversion efficiency are expected to increase ethanol production, which will necessarily reduce the amount of recoverable biomass fuel produced. Further, Highlands Ethanol has determined that it is not economically feasible to recover additional biogenic fuel. To minimize GHG emissions from this boiler, natural gas will be the sole fuel fired. Natural gas is the lowest GHG emitting fossil fuel available.

As summarized in Table E-23, the highest level of control is the use of low GHG emitting fuels, efficient combustion and energy efficiency. To satisfy GHG BACT, the peaking boiler will be fired solely with natural gas, will operate to provide peak steam loads and auxiliary steam and will implement good combustion practices as noted previously to meet CO and VOC BACT requirements.

5.3.6.4 Biogas Backup Flare

During periods when the biomass boiler is unavailable and/or the biogas flow rate exceeds the biomass boiler capacity, the biogas will be burned in the backup flare. Biogas is a biogenic fuel and as noted in Section 5.3.6.2, biogenic fuels can be determined to be inherently BACT per EPA guidance. Operation of the backup flare will be limited only to those periods when the biomass boiler is down, there is surplus biogas, or the process is down and steam from the biomass boiler is not required. The firing of biogenic fuel and limiting operation is BACT for the backup flare.

5.3.6.5 Emergency Engines

The emergency generator and fire pump diesel engines will only operate for readiness testing and during emergencies. BACT for these engines is limited operation, no more than 100 hours per year for testing and maintenance, and good combustion practices. This is consistent with the BACT findings summarized in Table E-23.

5.3.7 Summary of BACT Determinations

A summary of BACT determinations, including the control alternative determined to be BACT and the proposed BACT emission limits for each pollutant and emission source subject to PSD review is presented in Table 5-4.

Table 5-4. Summary of BACT Determinations

Pollutant	Emission Source	BACT Control Alternative	Proposed BACT Emission Limits
VOC	Liquid/Solid Separation	RTO	99% control
	Fermentation/Distillation/ Propagation	RTO	99% control
	E95 & Denaturant Storage	Internal Floating Roof Tanks	
	Product Shift Tanks	RTO	99% control
	Product Loadout	RTO	99% control
	Anaerobic Digestion	Flare	98% control
	Cooling Tower	Monitor Cooling Water for VOCs	
	Biomass Boiler	Good Combustion Practices	0.005 lb/MMBtu (24 hour average)
	Peaking Boiler	Good Combustion Practices	0.0014 lb/MMBtu
	Fire Pump Engine	Good Combustion Practices Use of ULSD Limit Operation to 100 non-emergency hours/year	0.3 g/hp·hr
	Emergency Generators	Good Combustion Practices Use of ULSD Limit Operation to 100 non-emergency hours/year	0.64 g/kW·hr
	Stillage Loadout	Best Management Practices	
	Fugitive Equipment Leaks	LDAR Program	

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Table 5-4. Summary of BACT Determinations (continued)

Pollutant	Emission Source	BACT Control Alternative	Proposed BACT Emission Limits
$PM_{2.5}/PM_{10}$	Misc. Storage Silos	Fabric Filter	0.005 gr/dscf
	Cooling Tower	Drift Eliminator	0.0005% Drift Loss
	Biomass Boiler	Fabric Filter	0.01 lb/MMBtu (filterable)
	Peaking Boiler	Natural Gas Firing	0.0022 lb/MMBtu (filterable)
	Fire Pump Engine	Good Combustion Practices Use of ULSD Limit Operation to 100 non-emergency hours/year	0.15 g/hp·hr (filterable)
	Emergency Generators	Good Combustion Practices Use of ULSD Limit Operation to 100 non-emergency hours/year	0.2 g/kW·hr (filterable)
NO_X	Biomass Boiler	SNCR	0.08 lb/MMBtu (30-day rolling)
	Peaking Boiler	Low-NOx Burners with FGR	0.035 lb/MMBtu
	Fire Pump Engine	Good Combustion Practices Use of ULSD Limit Operation to 100 non-emergency hours/year	2.7 g/hp·hr
	Emergency Generators	Good Combustion Practices Use of ULSD Limit Operation to 100 non-emergency hours/year	5.76 g/kW·hr

Table 5-4. Summary of BACT Determinations (continued)

Pollutant	Emission Source	BACT Control Alternative	Proposed BACT Emission Limits
SO_2	Biomass Boiler	Limestone Injection	0.06 lb/MMBtu (30-day rolling) 0.12 lb/MMBtu (24-hour rolling) 0.14 lb/MMBtu (3-hour block)
	Peaking Boiler	Natural Gas	0.0056 lb/MMBtu
	Biogas Backup Flare	H_2S Scrubber	
	Emergency Generators Fire Pump Engine	Good Combustion Practices Use of ULSD Limit Operation to 100 non-emergency hours/year	0.0015% sulfur content
CO	Biomass Boiler	Good Combustion Practices	0.1 lb/MMBtu (30-day rolling)
	Peaking Boiler	Good Combustion Practices	0.037 lb/MMBtu
	Fire Pump Engine	Good Combustion Practices Use of ULSD Limit Operation to 100 non-emergency hours/year	2.6 g/hp·hr
	Emergency Generators	Good Combustion Practices Use of ULSD Limit Operation to 100 non-emergency hours/year	3.5 g/kW·hr

6.0 AMBIENT AIR QUALITY IMPACT ANALYSIS

The ambient air quality analysis addresses several PSD requirements. These include:

- a significant impact analysis (SIA) for the project itself,
- an interactive source analysis that demonstrates compliance with NAAQS and PSD increments and includes emissions from the project as well as other facilities in the vicinity of the significant impact area of the project,
- an assessment of pre-construction monitoring requirements,
- an assessment of Class I area modeling requirements, and
- an additional impacts analysis that addresses community growth impacts on air quality, project impacts on local soils and vegetation, and visibility impairment resulting from the project.

6.1 Significant Impact Analysis

The purpose of the SIA is to assess the need for interactive source modeling. For the SIA, a criteria pollutant emission inventory is prepared and a Good Engineering Practice (GEP) stack height analysis is performed to identify emissions, stack parameters, and building downwash parameters for input to the dispersion model. A receptor grid and meteorological data are also prepared for input to the dispersion model. Ambient concentrations resulting from the proposed facility configuration are then predicted by the dispersion model and compared to SILs prescribed by the USEPA and FDEP. If the predicted concentrations are less than the SILs, then compliance with NAAQS and ambient increment standards is demonstrated and no additional modeling is required. Conversely, if the predicted concentrations are greater than the SILs, then an interactive source analysis is required to demonstrate compliance with the NAAQS and ambient increment standards. The SIA is pollutant-specific. For example, if predicted CO concentrations are less than the SILs and predicted SO_2 concentrations are greater than the SILs, then an interactive source analysis is not required for CO but is required for SO_2.

6.1.1 Site Location

The site location is described in Section 2.1 of this application and presented in Figure 2-1. A site plan is presented in Appendix C.

6.1.2 SIA Emission Inventory

Potential emissions for the project are presented in Section 3 of this application. In addition to the potential emissions listed there, USEPA modeling guidelines require evaluation of various operating loads for the proposed boilers. Load conditions are evaluated because model-predicted concentrations from reduced load conditions can be greater than from full load conditions. This results from reduced plume rise due to reduced exhaust flow. The load conditions evaluated are full load, 75% load, and 50% load.

Table 6-1 presents the stack and exhaust parameters modeled for the project's point sources. Included are the three load conditions for the boilers. Coordinates for each stack were identified by mapping the site plan to rectified aerial photographs of the site. Universal Transverse Mercator (UTM) coordinates of each stack are projected to UTM Zone 17 and the 1983 North American Datum (NAD83). Figure 6-1 shows the stack locations on the plot plan.

Table 6-2 presents the emissions modeled for the project's point sources. Included are the three load conditions for the boilers. Short-term emission rates are modeled for all pollutants for comparison to annual SILs, which provides for a conservative assessment of annual significant impacts.

6.1.3 Good Engineering Practice Stack Height Analysis

A GEP stack height analysis was conducted to evaluate whether the plumes emitted from the stacks are subjected to building wake effects. If a stack is sufficiently close to a large building, the plume can be entrained in the building's wake. The winds in the wake of the building cause the plume's rise to be diminished, which results in increased ground level ambient concentrations.

There are two definitions of GEP stack height: formula GEP stack height; and regulatory GEP stack height. The USEPA requires building downwash effects to be evaluated when a stack is less than formula GEP stack height (see Equation 6-1 below). Regulatory GEP stack height is either 65 meters or formula GEP stack height, whichever is greater. Sources are not allowed to take credit for ambient air concentrations that result from stacks that are higher than regulatory GEP stack height.

An analysis of the stack heights with respect to GEP was conducted in accordance with the USEPA's guideline for air quality impact modeling. The USEPA's Building Profile Input Program for PRIME (BPIPPRM, version 04274; USEPA, 2004a) was used to compute the formula GEP stack heights and to generate wind direction specific building profiles for sequential modeling. Formula GEP stack height is defined as:

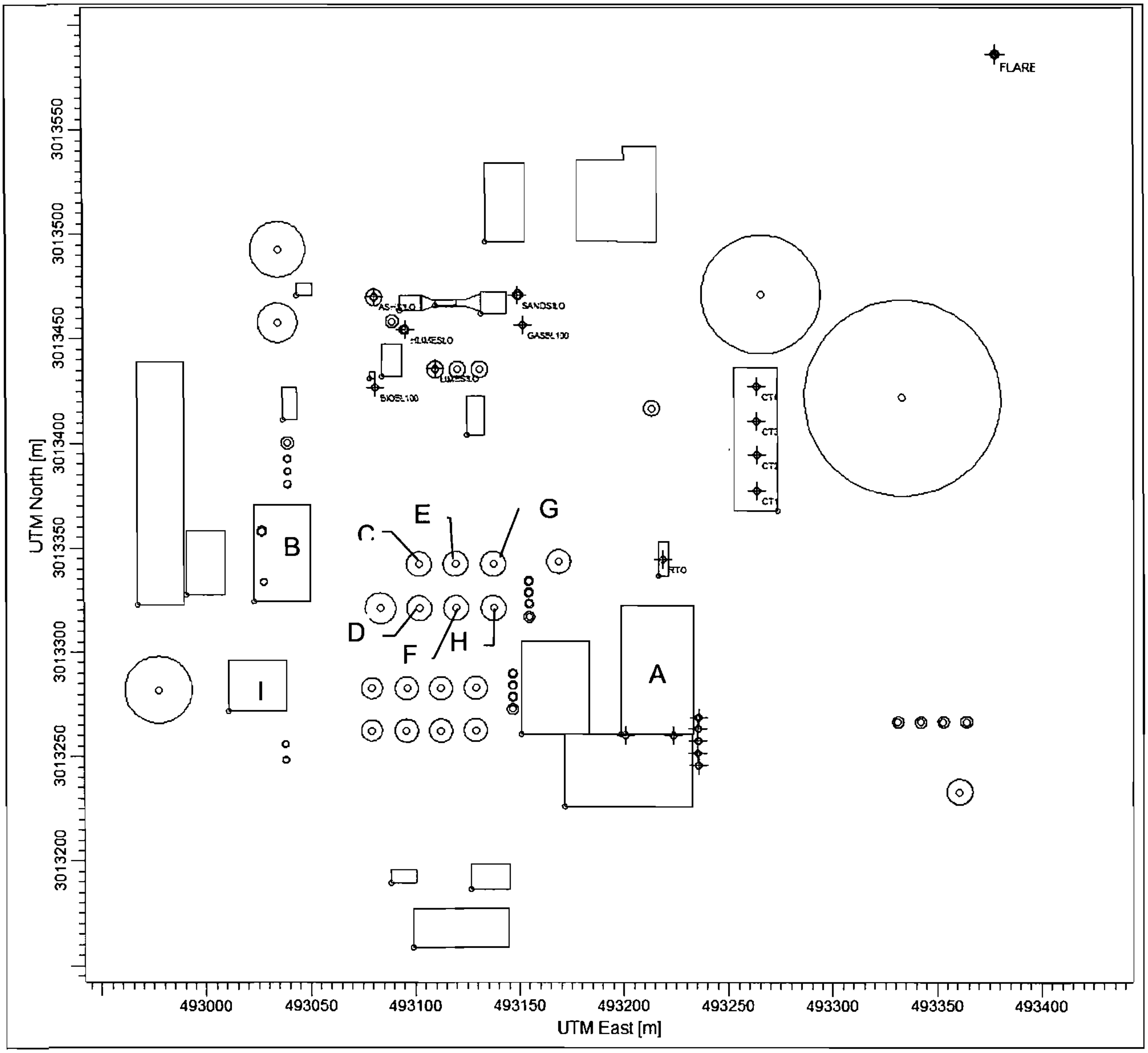
$$H_{GEP} = H_B + 1.5L_B \tag{6-1}$$

where:

H_{GEP} = formula GEP stack height,
H_B = the building's height above stack base, and
L_B = the lesser of the building's height or maximum projected width.

Table 6-1. Stack and Exhaust Parameters

Stack (Load)	UTM Easting (m)	UTM Northing (m)	Base Elevation (m)	Stack Height (m)	Exit Diameter (m)	Exhaust Flow (acms)	Exhaust Temp. (ºK)	Exit Velocity (m/s)
Bio. Boiler (100%)	493,081.6	3,013,426.8	9.24	39.6	2.13	35.4	352.6	9.9
Bio. Boiler (75%)	493,081.6	3,013,426.8	9.24	39.6	2.13	26.6	352.6	7.4
Bio. Boiler (50%)	493,081.6	3,013,426.8	9.24	39.6	2.13	17.7	352.6	5.0
Peak. Boiler (100%)	493,152.2	3,013,456.5	9.24	10.0	1.22	14.0	450	12.0
Peak. Boiler (75%)	493,152.2	3,013,456.5	9.24	10.0	1.22	10.5	450	9.0
Peak. Boiler (50%)	493,152.2	3,013,456.5	9.24	10.0	1.22	7.0	450	6.0
RTO	493,219.1	3,013,344.4	9.24	10.0	0.91	9.4	305	14.4
Flare	493,377.9	3,013,586.2	9.44	3.05	1.2	21.3	1273	20.0
CT Cell No. 1	493,263.6	3,013,377.7	9.24	16.5	10.0	691.5	308	8.8
CT Cell No. 2	493,263.5	3,013,394.3	9.24	16.5	10.0	691.5	308	8.8
CT Cell No. 3	493,263.5	3,013,410.9	9.24	16.5	10.0	691.5	308	8.8
CT Cell No. 4	493,263.6	3,013,427.3	9.24	16.5	10.0	691.5	308	8.8
Lime Silo	493,110.1	3,013,435.8	9.24	10.4	0.46	1.2	298	7.2
Ash Silo	493,080.9	3,013,470.2	9.25	10.4	0.46	1.2	297	7.2
Hydrated Lime Silo	493,095.6	3,013,454.3	9.24	10.4	0.46	1.2	300	7.2
Sand Silo	493,149.6	3,013,471.1	9.26	10.4	0.46	1.2	300	7.2
Cellulose Silo	493,235.8	3,013,257.6	9.14	14.6	0.31	1.2	300	16.2
Wheat Bran Silo	493,235.8	3,013,263.2	9.14	14.6	0.31	1.2	300	16.2
Ammonium Sulf. Silo	493,235.8	3,013,251.6	9.14	12.2	0.31	1.2	300	16.2
Potassium Phos. Silo	493,235.8	3,013,245.8	9.14	14.6	0.31	1.2	300	16.2
Urea Process Silo	493,235.8	3,013,268.9	9.14	12.2	0.31	1.2	300	16.2
Wheat Bran Transfer	493,200.9	3,013,260.3	9.14	11.0	0.15	0.31	294	16.8
Urea Transfer	493,233.6	3,013,260.3	9.14	11.0	0.15	0.31	294	16.8



Note: Structures are labeled with letter codes that refer to Table 6-3. Only those structures that contributed to downwash are labeled. All others are listed on the site plan provided in Appendix C. Stacks and vents are marked in Red.

Figure 6-1
Site Plan and BPIPPRM Cross-Reference

Table 6-2. Modeled Emission Rates [a]

Stack (Load)	SO_2 (g/s)	PM_{10} (g/s)	$PM_{2.5}$ (g/s)	NO_2 (g/s)	CO (g/s)
Bio. Boiler (100%)	4.76	1.70	1.70	3.40	6.80
Bio. Boiler (75%)	3.57	1.28	1.28	2.55	5.10
Bio. Boiler (50%)	2.38	0.85	0.85	1.70	3.40
Peak. Boiler (100%)	0.067	0.048	0.048	0.419	0.443
Peak. Boiler (75%)	0.050	0.036	0.036	0.314	0.332
Peak. Boiler (50%)	0.034	0.024	0.024	0.210	0.221
RTO	0.00212	0.000832	0.000832	0.0132	0.0140
Flare	1.260	0.0308	0.0308	0.8568	4.6619
CT Cell No. 1	--	0.00723	0.00723	--	--
CT Cell No. 2	--	0.00723	0.00723	--	--
CT Cell No. 3	--	0.00723	0.00723	--	--
CT Cell No. 4	--	0.00723	0.00723	--	--
Ash Silo	--	0.0135	0.0135	--	--
Sand Silo	--	0.0135	0.0135	--	--
Limestone Silo	--	0.0135	0.0135	--	--
Hydrated Lime Silo	--	0.0135	0.0135	--	--
Cellulose Silo	--	0.0134	0.0134	--	--
Ammonium Sulfate Silo	--	0.0134	0.0134	--	--
Potassium Phosphate Silo	--	0.0134	0.0134	--	--
Bulk Urea Silo	--	0.0134	0.0134	--	--
Wheat Bran	--	0.0134	0.0134	--	--
Wheat Bran Transfers	--	0.0036	0.0036	--	--
Urea Transfers	--	0.0036	0.0036	--	--
Paved Road Fugitive (total)	--	0.01250	0.00163	--	--
Ethanol Loadout Loop	--	0.00154	0.00020	--	--
Small Delivery Loop	--	0.00052	0.00007	--	--
Large Delivery Loop	--	0.00474	0.00062	--	--
Bagasse Delivery		0.00108	0.00014		
Parking Lot	--	0.00462	0.00060	--	--

[a] All emission rates based on proposed BACT emission limits. See Appendix B.

BPIPPRM requires a digitized blueprint of the facility's buildings and stacks. The position and height of buildings relative to the stack positions must be evaluated in the GEP analysis. The building positions were obtained from a site plan of the proposed project. Coordinates for each building tier corner were identified by overlaying the site plan onto rectified aerial photographs of the site. Roof heights for the project were obtained from preliminary designs of the facility structures.

The layout of the facility is displayed in Figure 6-1. The project stack locations are also identified in this figure. The building heights shown in Figure 6-1 are referenced to the base elevation assigned from National Elevation Dataset (NED) elevation data processed through the AERMAP program. The associated BPIPPRM building-tier identifications are provided in Table 6-3.

Table 6-4 provides the results of the analysis. Presented for each stack are:

- the structure(s) that defines formula GEP for the stack (controlling structure),
- the height of the controlling structure,
- the projected width of the controlling structure,
- structure shape (i.e., squat or tall),
- formula GEP stack height,
- regulatory GEP stack height, and
- the actual stack height.

The stack heights are less than the calculated formula GEP height. Therefore, building wake effects will be evaluated for all of the stacks in all modeling runs. Because the actual stack heights are less than both formula and regulatory GEP heights, the actual stack heights are modeled. BPIPPRM input and output files are provided on CDROM per the nomenclature described in Appendix F.

6.1.4 Modeling Protocol

This section provides the modeling protocol including model selection, receptor grid design, and meteorological data.

6.1.4.1 Model Selection

AERMOD (version 12060; USEPA, 2004b) was selected to predict ambient concentrations in simple, complex, and intermediate terrain. AERMOD is the recommended sequential model in USEPA's Guideline on Air Quality Models (40 CFR 51, Appendix W). The regulatory default option was used except for the beta option for the two horizontal vents from the wheat and urea transfer operations.

Table 6-3. BPIPPRM Building-Tier/Site Plan Cross Reference [a]

BPIPPRM Bldg-Tier No.	Site Plan Building Tier(s)	Tier Height (m)	BPIPPRM Bldg-Tier No.	Site Plan Building Tier(s)	Tier Height (m)
1	A	27.43	52	F	30.33
6	B	42.67	82	G	30.33
43	C	30.33	85	H	30.33
46	D	30.33	151	I	41.76
49	E	30.33			

[a] Letter codes refer to building tiers shown in blue on Figure 6-1.

Table 6-4. BPIPPRM Results

Stack	Controlling Bldg-Tier	Bldg-Tier Height (m)	Bldg-Tier Projected Width (m)	Bldg-Tier Shape	Formula GEP Stack Height (m)	Regulatory GEP Stack Height (m)	Actual Stack Height (m)
Biomass Boiler	6,151	41.76	41.86	Squat	104.3	104.3	39.62
Peaking Boiler	6,151	41.76	44.13	Squat	104.3	104.3	10.0
RTO	85,52,82	30.33	31.26	Squat	75.72	75.72	10.0
Flare	None	NA	NA	NA	65.0	NA	3.05
CT Cell No. 1	85,52,82	30.33	30.36	Squat	75.72	75.72	16.49
CT Cell No. 2	85,52,82	30.33	30.33	Squat	75.72	75.72	16.49
CT Cell No. 3	85,52,82	30.33	30.33	Squat	75.72	75.72	16.49
CT Cell No. 4	49,43,52,82	30.33	38.76	Squat	75.72	75.72	16.49
Ash Silo	43,46,49	30.33	31.39	Squat	75.71	75.71	10.36
Hydrated Lime Silo	6,151	41.76	41.22	Squat	103.49	103.49	10.36
Sand Silo	6,151	41.76	43.31	Squat	104.28	104.28	10.36
Limestone Silo	6,151	41.76	41.86	Squat	104.3	104.3	10.36
Cellulose Silo	46,43,52	30.33	30.35	Squat	75.82	75.82	14.63
Ammonium Sulf. Silo	43,46,49	30.33	37.96	Squat	75.82	75.82	12.19
Potassium Phos. Silo	43,46,49	30.33	38.30	Squat	75.82	75.82	14.63
Urea Process Silo	82,49,85	30.33	30.33	Squat	75.82	75.82	12.19
Wheat Bran Silo	46,43,52	30.33	30.35	Squat	75.82	75.82	14.63
Wheat Bran Transfer	43,46,49	30.33	38.53	Squat	75.82	75.82	10.97
Urea Transfer	46,43,52	41.76	41.22	Squat	103.49	103.49	10.36

This option commands AERMOD to:

- use the elevated terrain algorithms requiring input of terrain height data for receptors and emission sources,
- use stack tip downwash (building downwash automatically overrides),
- use the calms processing routines,
- use buoyancy-induced dispersion, and
- use the missing meteorological data processing routines.

Additionally, model options were set to use rural dispersion coefficients.

6.1.4.2 Urban Land Use Assessment

Dispersion coefficients for air quality modeling were selected based on the land use classification technique suggested by Auer (Auer, 1978), which is the preferred method of the USEPA. The classification determination involves assessing land use by Auer's categories within a 3-kilometer radius of the proposed site. Urban dispersion coefficients should be selected if greater than 50 percent of the area consists of urban land use types; otherwise, rural coefficients apply.

Land use categories for areas within the 3-kilometer radius of the facility were identified from US Geological Survey (USGS) maps and observation. Figure 6-2 shows the 3-kilometer radius centered on the biomass boiler stack. The area within 3-kilometers of the facility is primarily rural. Therefore, rural dispersion coefficients were selected for the air quality modeling.

6.1.4.3 Receptors

A total of 2,545 receptors were placed along the facility fenceline and in seven nested Cartesian grids. Receptor spacing is as follows for each of the seven grids:

- inner grid = 50 meters (out to 500 meters from the property boundary),
- second grid = 100 meters (out to 1 kilometer),
- third grid = 200 meters (out to 2 kilometer),
- fourth grid = 400 meters (out to 4 kilometers),
- fifth grid = 800 meters (out to 8 kilometers),
- sixth grid = 1,600 meters (out to 16 kilometers), and
- outer grid = 3,200 meters (out to 32 kilometers).

Fence line receptor spacing is no more than 25 meters.

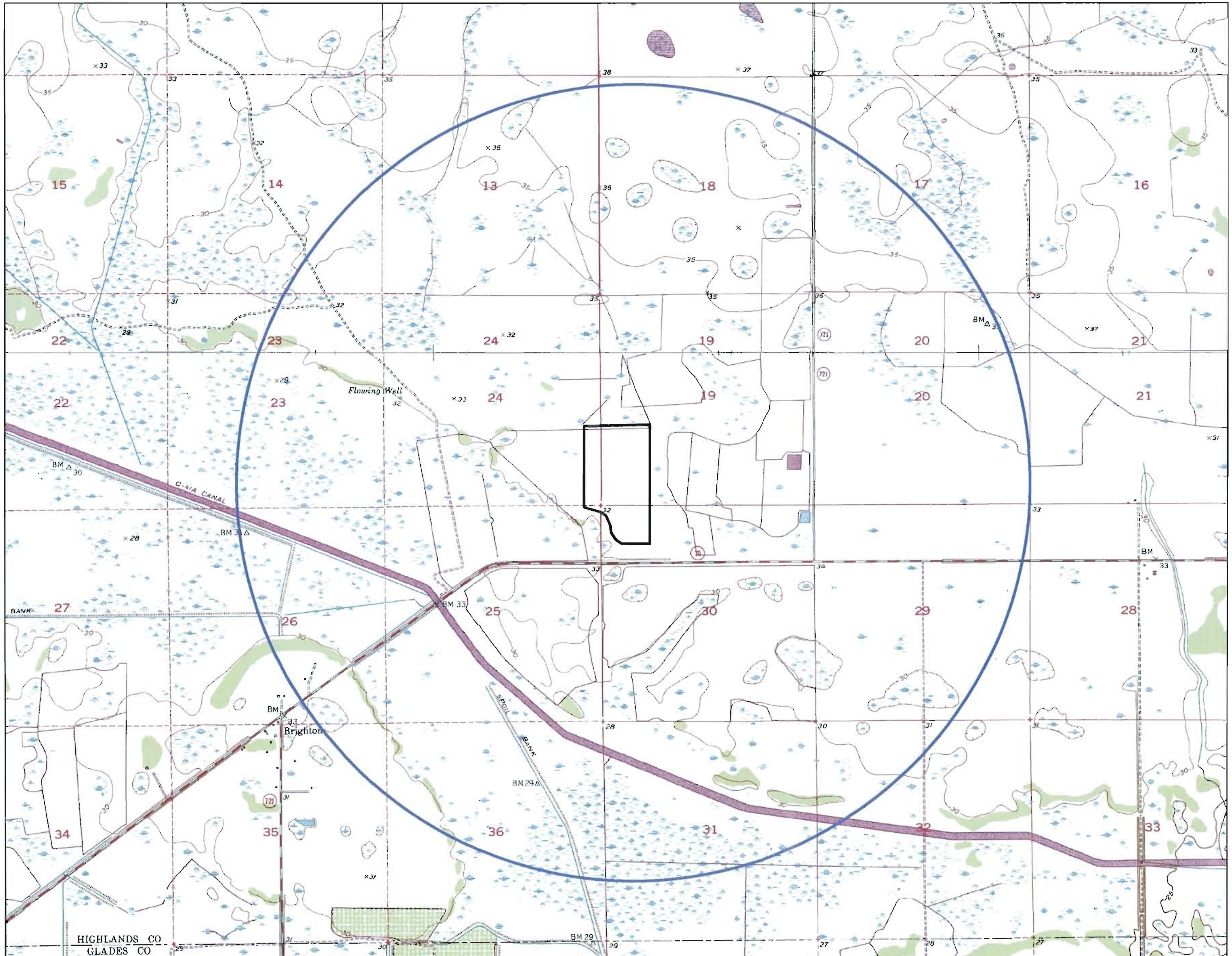
The grid has a total coverage of 64 kilometers by 64 kilometers, covering portions of Highlands, Glades, Okeechobee, Martin, and Palm Beach Counties. Figure 6-3 presents the entire modeling domain on a map of the area. Figure 6-4 presents the receptors within 10 km of the facility. Figure 6-5 presents a detailed view of the receptors within 1 km of the facility.

Receptor elevations were assigned by using USEPA's AERMAP (version 11103; USEPA, 2004c) software tool, which is designed to extract elevations from USGS NED files. AERMAP is the terrain preprocessor for AERMOD and uses the following procedure to assign elevations to a receptor:

- For each receptor, the program searches through the NED data index files to determine the two profiles (longitudes or eastings) that straddle this receptor.
- For each of these two profiles, the program then searches through the nodes in the index file to determine which two rows (latitudes or northings) straddle the receptor.
- The program then calculates the coordinates of these four points and determines the NED direct access file and the record numbers that correspond to these points.
- It reads the elevations for these four points from the appropriate direct access file.
- A 2-dimensional distance-weighted interpolation is used to determine the elevation at the receptor location based on the elevations at the four nodes determined above.

When 1 degree NED data are used, the receptor or source location may fall outside the range of the profiles in the NED file. Elevations for these receptors or sources located near the edges of a NED file are assigned values based on the nodes that are closest to the receptor or source location.

1 degree (30 meter) NED data were used as inputs to AERMAP. The 1 degree NED data are produced from digitized map contours or from manual or automated scanning of aerial photographs. A single 1 degree NED data file covering the modeling domain was downloaded from the USGS seamless server and used for this analysis. The 1 degree NED data file consists of a regular array of elevations referenced horizontally in the latitude/longitude system, with a uniform horizontal spacing of 1 degree or roughly 30 meters. AERMAP input and output files are provided on CDROM per the nomenclature described in Appendix F.



LEGEND

Property Boundary

3 km Radius From Boiler Stacks

Urban Land Use

LOCATION MAP

NOTES & SOURCES

Map Projection: NAD 83, UTM Zone 17N, Meters
Basemap data from US Geologic Survey 7-1/2 minute
Topographic Map Source: FL Land Boundary Information System

TITLE

Highlands Ethanol
Urban Land Use Evaluation

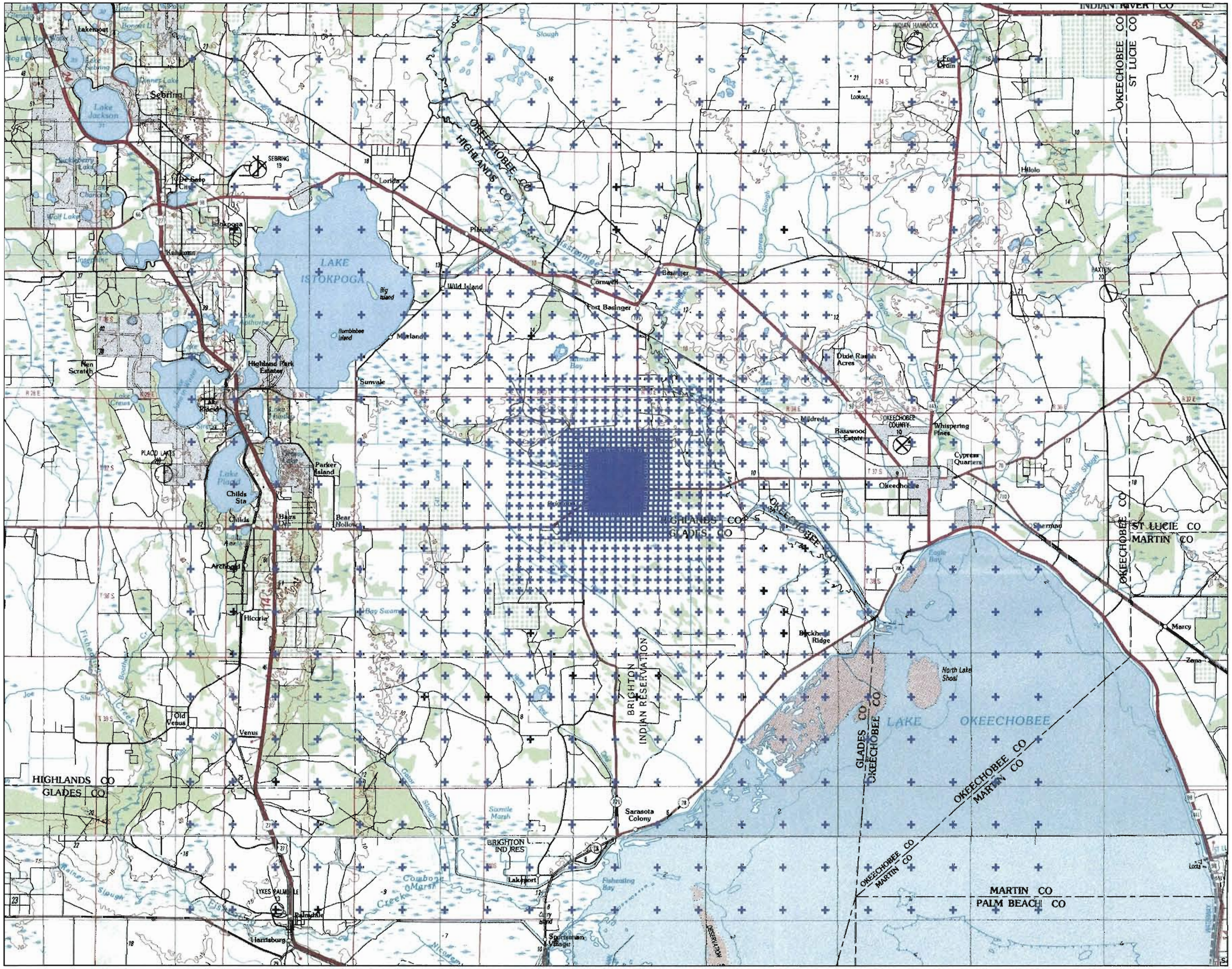
0 1 Kilometers

amec

AMEC Environment & Infrastructure
Portland, Maine

FIGURE

6-2



LEGEND

Property Boundary

Receptor

LOCATION MAP

NOTES & SOURCES

Map Projection: NAD 83, UTM Zone 17N, Meters
Basemap data from US Geologic Survey 1°× 2° Series
Topographic Map Source: FL Land Boundary Information System

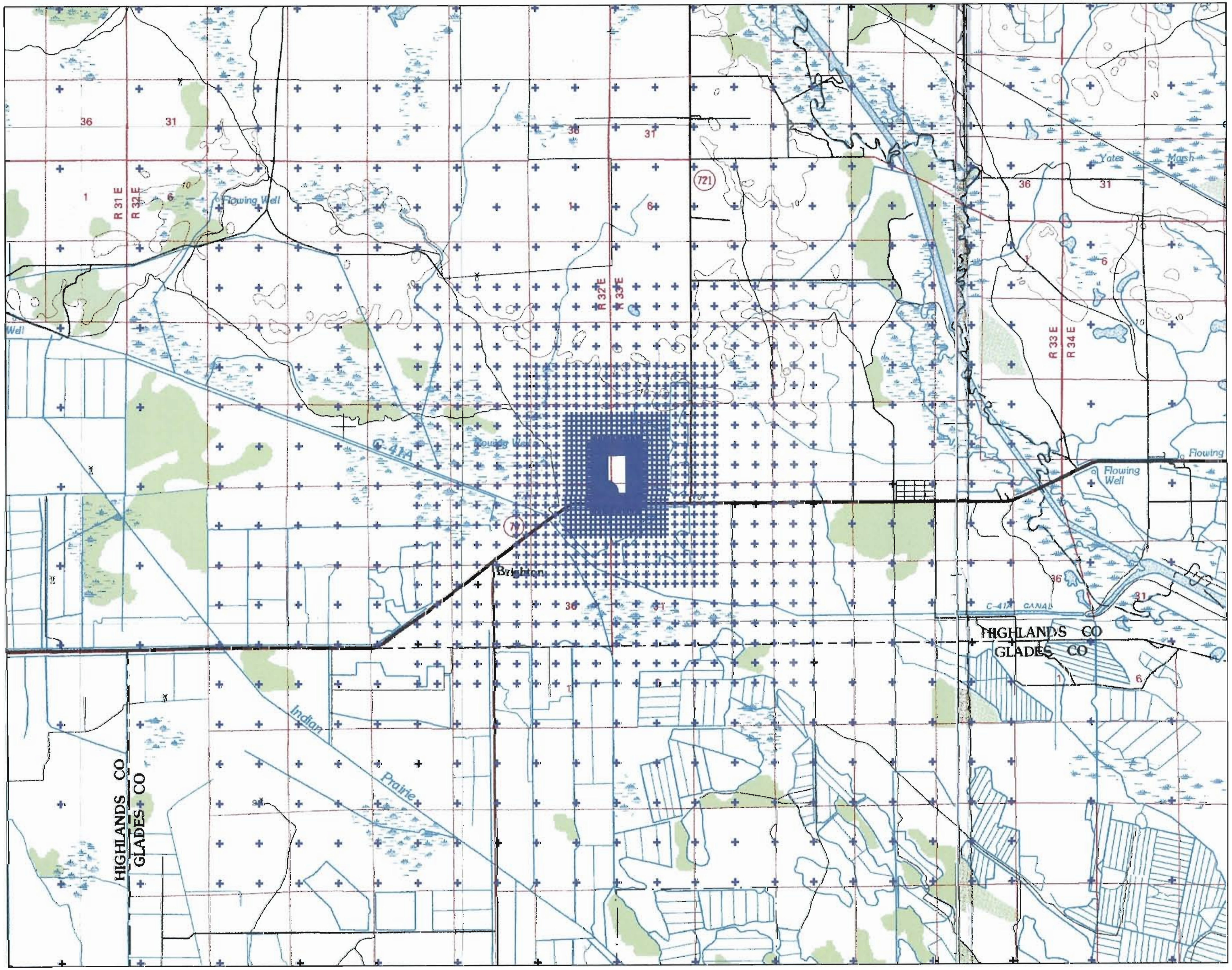
TITLE

Highlands Ethanol
Receptors - Modeling Domain

0 10 Kilometers

amec
AMEC Environment & Infrastructure
Portland, Maine

FIGURE
6-3



LEGEND

Property Boundary

Receptor

LOCATION MAP

NOTES & SOURCES

Map Projection: NAD 83, UTM Zone 17N, Meters
Basemap data from US Geologic Survey 0.5°×1.0° Series
Topographic Map Source: FL Land Boundary Information System

TITLE

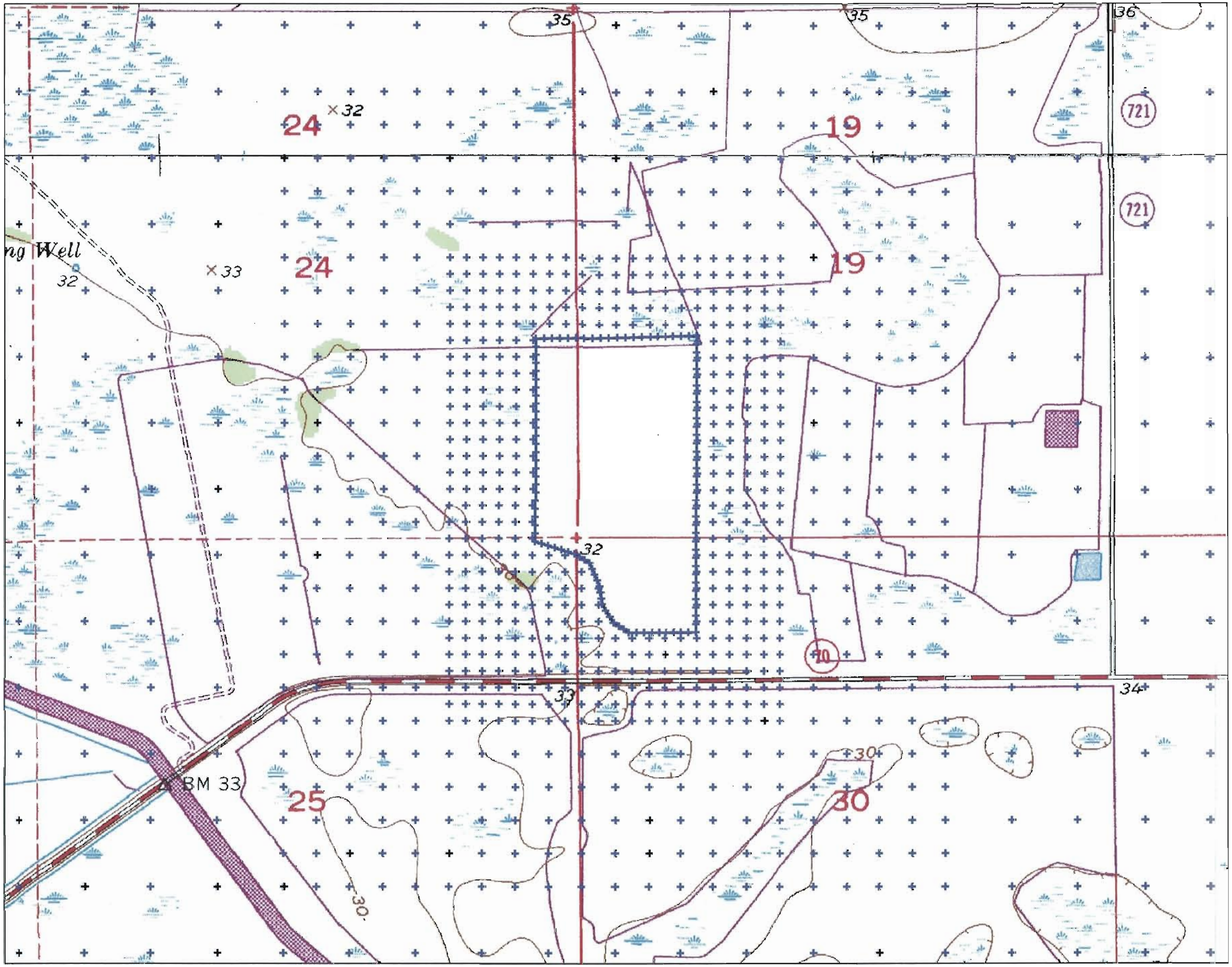
Highlands Ethanol
Receptors Within 10 km of Project

0 2 Kilometers

amec

AMEC Environment & Infrastructure
Portland, Maine

FIGURE
6-4



LEGEND

Property Boundary

Receptor

LOCATION MAP

NOTES & SOURCES

Map Projection: NAD 83, UTM Zone 17N, Meters
Basemap data from US Geologic Survey 7-1/2 minute
Topographic Map Source: FL Land Boundary Information System

TITLE

Highlands Ethanol
Receptors Within 1 km of Project

0 0.5 Kilometers

amec

AMEC Environment & Infrastructure
Portland, Maine

FIGURE
6-5

6.1.4.4 Meteorological Data

USEPA recommends that AERMOD be run with a minimum of 5 years of National Weather Service (NWS) data or 1 year of on-site meteorological data. A wind rose for the 2006 to 2010 data is provided in Figure 6-6. The five-year composite wind rose demonstrates that prevailing winds are primarily from easterly and westerly directions.

6.1.5 Load Analysis Modeling Results

The results of the load analysis for the boilers are presented in Table 6-5. The results show that the maximum concentrations are predicted for the "100% load" operating scenario for all pollutants and averaging periods except the following:

- The 24-hour SO_2 maximum significant impact concentration occurred at 75% load.
- The annual $PM_{2.5}$ maximum significant impact occurred at 75% loading.
- The 24-hour and annual PM_{10} maximum significant impact occurred at 75% loading.

The highest concentrations for each averaging period are used in the SIA for all pollutants. AERMOD input and output files are provided on CDROM per the nomenclature described in Appendix F.

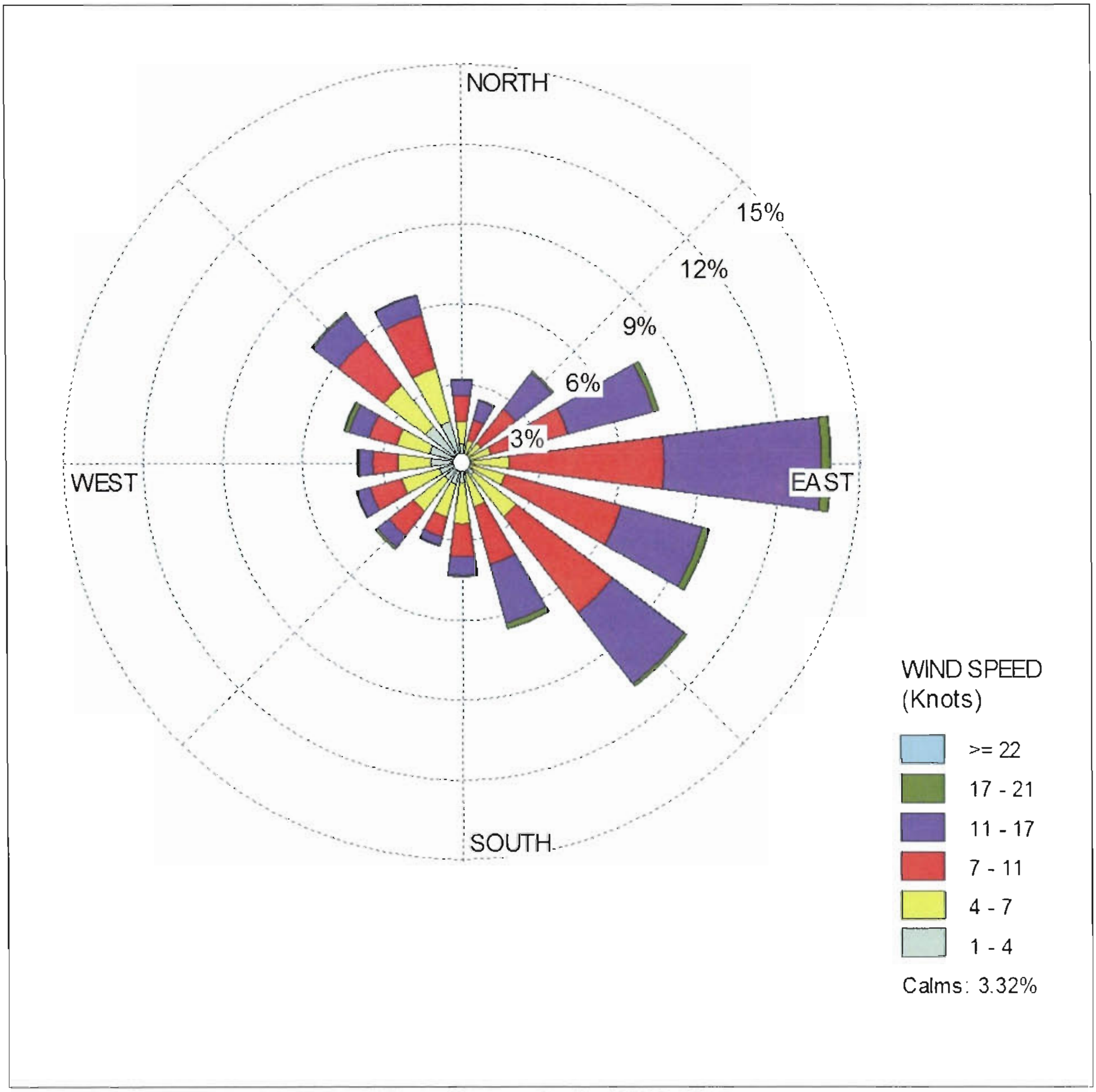
6.1.6 SIA Modeling Results

The predicted concentrations were compared to SILs established by the USEPA for SO_2, PM_{10}, $PM_{2.5}$, NO_2, CO, and Pb. The predicted concentrations include emissions from all proposed project emission sources. The boiler operating loads identified in Table 6-5 that resulted in the highest predicted concentrations were used in the significant impact analysis. The significant impact analysis results are presented in Table 6-6. The highest predicted concentrations are presented rather than the highest second high (HSH) concentrations as is appropriate for comparison to SILs. If the modeling results for a particular pollutant are less than the corresponding SILs, then no further analysis for that pollutant is required.

Predicted maximum concentrations for CO and Pb for all averaging periods are less than SILs. Thus, the project is predicted to comply with the ambient air quality standards and increments for these pollutants and averaging periods. No interactive source modeling is required for these pollutants.

Predicted maximum concentrations for SO_2, PM_{10}, $PM_{2.5}$, and NO_2 are greater than SILs. Consequently, interactive modeling is required for these pollutants. The significant impact areas for each were identified and are as follows:

- SO_2 8.4 km,
- PM_{10} 1.1 km,
- $PM_{2.5}$ 3.0 km, and
- NO_2 5.5 km.



5-Year Composite for 2006-2010

Figure 6-6
Wind Rose for West Palm Beach NWS Meteorological Data

Table 6-5. Facility Load Analysis Modeling Results

Pollutant	Averaging Period	Maximum Predicted Concentration (µg/m³)[a] 100% Load	75% Load	50% Load	Maximum Load Case
SO_2	1-hour	55.9	54.7	53.9	100%
	3-hour	106.4	106.4	106.3	100%
	24-hour	43.0	43.0	43.0	75%
	Annual	2.76	2.67	2.51	100%
$PM_{2.5}$	24-hour	9.55	9.49	9.14	100%
	Annual	1.51	1.51	1.51	75%
PM_{10}	24-hour	13.6	13.7	13.3	75%
	Annual	1.67	1.67	1.67	75%
NO_2	1-hour	61.6	54.3	44.6	100%
	Annual	3.13	2.95	2.71	100%
CO	1-hour	416.4	416.3	416.2	100%
	8-hour	243.3	243.3	243.2	100%
Pb	3-month[b]	0.0021	0.0020	0.0017	100%

[a] µg/m³ = micrograms per cubic meter

[b] based on a one month average, a conservative assumption

Table 6-6. Significant Impact Analysis Modeling Results

Pollutant (Load)	Averaging Period	Year	Date (Hr)	Receptor UTM Coordinates (km)	AERMOD Predicted Conc. (µg/m³)	Significant Impact Levels (µg/m³)
SO_2	1-hour			493.28, 3013.61	55.9	7.9[b]
	3-hour	2008	08/19(06)	493.35, 3013.65	106.4	25
	24-hour	2009	11/09(24)	493.28, 3013.61	43.0	5
	Annual			492.75, 3013.65	2.76	1
$PM_{2.5}$	24-hour			493.40, 3013.15	9.55	1.2
	Annual			492.91, 3013.53	1.51	0.3
PM_{10}	24-hour	2008	12/31	493.40, 3013.15	13.7	5
	Annual			492.91, 3013.53	1.67	1
NO_2	1-hour			493.55, 3113.45	61.6	7.6[b]
	Annual			492.91, 3013.53	3.13	1
CO	1-hour	2008	08/19(05)	493.35,3013.65	416.4	2,000
	8-hour	2008	08/19(08)	493.35, 3013.65	243.3	500
Pb	3-month	2007	05/31	492.65, 3013.30	0.0029	0.1

[a] based on a one month average, a conservative assumption

[b] interim levels set by EPA

Distances are referenced to the centroid of the boiler stacks. FDEP was contacted to obtain interactive source data. The interactive source analysis is presented in Section 6.2.

AERMOD input and output files are provided on CDROM per the nomenclature described in Appendix F.

6.2 Interactive Source Analysis

The purpose of the interactive source analysis is to demonstrate that emissions from the proposed project, combined with other sources in the vicinity while accounting for existing background ambient air quality, will result in ambient air quality that remains in compliance with NAAQS and ambient increment standards. For the interactive source analysis, background ambient air quality concentrations are identified from measurements collected in the vicinity, and an emissions inventory is obtained from FDEP for other emission sources that have the potential to impact the project's significant impact area. Dispersion modeling is performed with the interactive source inventory and predicted concentrations are compared to NAAQS and ambient increment standards. Based on the results of the SIA, the interactive source analysis is performed for SO_2, PM_{10}, $PM_{2.5}$, and NO_2.

6.2.1 Background Air Quality

Based on review of available data and discussions with FDEP, ambient monitors located in Palm Beach, Polk, and Highlands Counties were selected for the determination of background ambient air quality concentrations to be used in the NAAQS assessment. Table 6-7 provides identification and location information for the monitoring sites. The UTM coordinates of each site are projected to UTM Zone 17 and the 1983 North American Datum (NAD83).

Table 6-7. Background Air Quality Monitoring Sites

Monitor	USEPA AIRS ID	Address	UTM Coordinates (m)	Distance (km)	Direction
Archbold Station	12-055-0003	123 Main Drive	466263, 3007230	28	WSW
Belle Glade	12-099-0008	38145 State Rd. 80	533509, 2955937	70	SE
Lantana	12-099-0020	1199 Lantana Rd	593520, 2941340	124	SE
Del Ray Beach	12-099-2005	225 S Congress Ave	590447, 2926642	130	SE
Riviera Beach	12-099-3004	1050 15th St. W	492469, 2962073	138	SE

Table 6-8 summarizes the monitoring data for SO_2, PM_{10}, $PM_{2.5}$, and NO_2 collected in 2008, 2009, and 2010. As shown in Table 6-8, all measured concentrations for these pollutants are less than their respective NAAQS. The short-term concentrations represent the second-highest measurement recorded by the monitor during each year. As such, these data provide a conservative representation of background air quality in the region.

Table 6-8. Regional Ambient Air Quality Data [a]

Monitor Location	Pollutant	Averaging Period	Concentration ($\mu g/m^3$) [a] 2008	2009	2010	NAAQS ($\mu g/m^3$)
Riviera Beach	SO_2	1-hour [b]	10.5	14.1	19.7	196.5
		3-hour	10.5	13.1	18.3	1,300
Delray Beach	PM_{10}	24-hour	60	47	40	150
Belle Glade	$PM_{2.5}$	24-hour [c]	16.2	14.0	16.7	35
		Annual	6.2	6.1	6.0	15
Lantana	NO_2	1-hour [d]	--	45.2	58.3	188
		Annual	--	9.4	9.4	100

[a] Ambient monitoring data obtained from FDEP 2010 Monitoring Report and 1 hour data from EPA Datamart.
[b] 99th percentile of the highest daily 1-hour averaged values
[c] 98th percentile of the 24-hour values
[d] 98th percentile of the 1-hour averaged values
-- Monitor not in operation for full year

To provide a conservative analysis of the project's compliance with NAAQS, the maximum measured values presented in Table 6-8 were selected to represent background air quality in the modeling analysis. A summary of the selected background air quality concentrations is provided in Table 6-9.

Table 6-9. Background Air Quality for Dispersion Modeling

Pollutant	Averaging Period	Background Air Quality ($\mu g/m^3$)
SO_2	1-hour [a]	14.7
	3-hour	14.0
PM_{10}	24-hour	49.0
$PM_{2.5}$	24-hour [b]	15.6
	Annual	6.1
NO_2	1-hour [c]	51.8
	Annual	9.4

[a] based on 3 year 99th percentile of the highest daily 1-hour concentration
[b] based on 3 year 98th percentile of the 24-hour concentrations
[c] based on the 3 year 98th percentile of the 1-hour concentrations

6.2.2 Interactive Source Emissions Inventory and Modeling Results

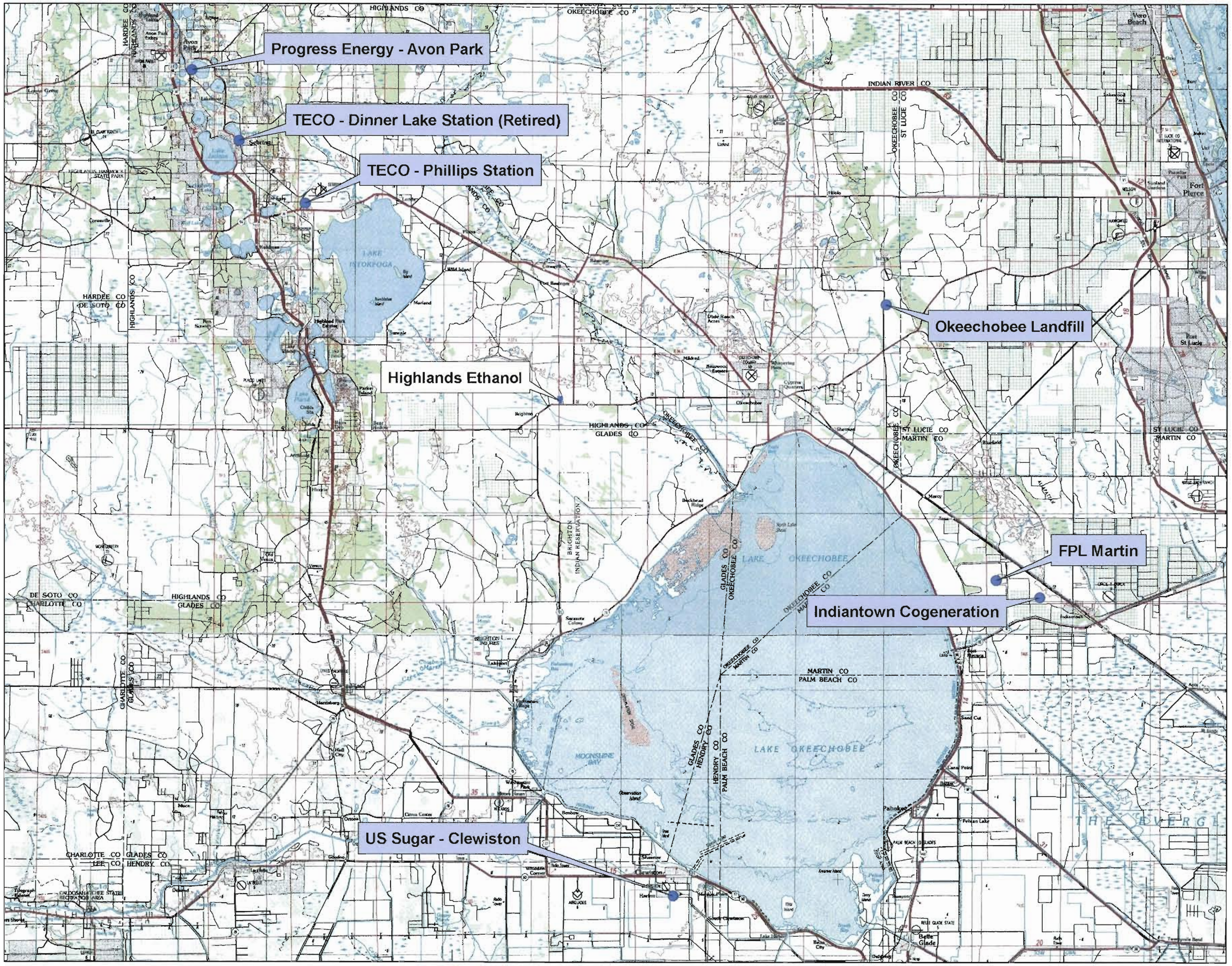
Highlands Ethanol requested FDEP to supply an inventory of other interactive sources to include in the dispersion modeling analysis. FDEP subsequently identified 53 facilities to potentially be included in the interactive modeling analysis. FDEP allowed the facilities with lower emissions and/or those that are more distant from the project site to be eliminated from the interactive modeling analysis by applying the "20D" rule, a screening method developed by the North Carolina Department of Natural Resources and Community Development (NCDNRCD, 1985). The 20D rule compares a facility's emissions for a given pollutant in terms of tons per year to a second value that is twenty times the distance ("D", in kilometers) between the project site and the facility being considered. A facility whose emissions in tons per year exceed the 20D value is included in the interactive modeling analysis. All other facilities can be removed from the inventory. Applying the 20D rule to the candidate list of other sources provided by FDEP reduced the number of interactive sources to seven. Of the seven sources selected, five are electric generating stations, and the remaining two are US Sugar – Clewiston and the Okeechobee Landfill. The locations of these facilities with respect to the project site are presented in Figure 6-7. Detailed AERMOD input data are provided in Appendix G.

Table 6-10 presents the results of the interactive modeling analysis. The results demonstrate that the facility will be in compliance with NAAQS and ambient increments for SO_2, PM_{10}, $PM_{2.5}$, and NO_2, even with interactive sources and background concentrations added to the analysis.

Table 6-10. PSD Class II Increment and NAAQS Analysis

Pollutant	Averaging Period	Project plus Interactive Sources (µg/m³)	PSD Class II Increments (µg/m³)	Background Air Quality (µg/m³)	Modeled Impacts plus Background (µg/m³)	NAAQS (µg/m³)
SO_2	1-hour [a]	133.8	--	14.7	148.5	196.5
	3-hour [b]	96.5	512	14.0	110.5	1300
	24-hour	43.4	91	--	--	d
	Annual	4.4	20	--	--	d
PM_{10}	24-hour [b]	10.8	30			
	24-hour [c]	9.7		49	58.7	150
	Annual	1.71	17	--	--	d
$PM_{2.5}$	24-hour [b]	8.3	9			
	24-hour [d]	9.5		21.3	30.8	35
	Annual	1.55	4	6.1	7.7	15
NO_2	1-hour [c]	92.7	--	51.8	144.5	188
	Annual	4.5	25	9.4	13.9	100

a. 4th highest maximum daily 1-hour average
b. Highest second highest value for PSD Class II Increment comparison
c. 6th Highest 24-Hour average
d. Highest 24 hour average for NAAQS comparison
e. 8th highest maximum daily 1-hour average
f. NAAQS withdrawn



LEGEND

Highlands Ethanol Property

Location of Interactive Source

LOCATION MAP

NOTES & SOURCES

Map Projection: NAD 83, UTM Zone 17N, Meters
Basemap data from US Geologic Survey 1°×2° Series
Topographic Map Source: FL Land Boundary Information System

TITLE

Highlands Ethanol
Interactive Source Locations

0 20 Kilometers

amec

AMEC Environment & Infrastructure
Portland, Maine

FIGURE 6-7

6.3 Pre-Construction Monitoring

Exemptions from pre-construction monitoring requirements can be requested if predicted ambient concentrations resulting from the proposed project are less than Significant Monitoring Concentrations (SMCs). Table 6-11 presents the concentrations predicted for the project against the relevant SMCs.

Table 6-11. Pre-Construction Monitoring Analysis Results

Parameter	Averaging Period	AERMOD Predicted Conc. (μg/m^3)	Significant Monitoring Conc. (μg/m^3)
SO_2	24-hour	43.0	13
$PM_{2.5}$	24-hour	9.55	4
PM_{10}	24-hour	14.4	10
NO_2	Annual	3.1	14
CO	8-hour	243.3	575
Pb [a]	3-month	0.0021	0.1

[a] Modeled Pb result is based on a 1-month average, which provides a conservative comparison to the 3-month SMC.

Predicted concentrations for NO_2, CO, and Pb are less than the SMCs. Based on these modeling results, Highlands Ethanol requests an exemption from pre-construction monitoring for these pollutants. AERMOD input and output files are provided on CDROM per the nomenclature described in Appendix F.

Predicted concentrations for SO_2 $PM_{2.5}$ and PM_{10} are greater than the SMCs. Readily available ambient monitoring data can be used to assess pre-construction air quality if:

- the existing monitoring locations are in areas that are representative of the project area,
- the data are of sufficient quality, and
- the data are current.

Based on review of available data and discussions with FDEP, ambient monitors located in Palm Beach, Polk, and Highlands Counties were selected for the determination of background ambient air quality concentrations to be used in the NAAQS assessment. Table 6-9 presents a summary of the most recent three years of ambient air monitoring data for SO_2, PM_{10}, $PM_{2.5}$, and NO_2. Table 6-12 presents the most recent three years of ambient monitoring data for ozone collected at the nearby Archbold Biological Station. The locations of these monitors were provided in Table 6-8.

Table 6-12. Ambient Ozone Air Quality Data, Archbold Biological Station

Monitor Location	Pollutant	Averaging Period	Concentration ($\mu g/m^3$) 2008	2009	2010	NAAQS ($\mu g/m^3$)
Archbold Station	O_3	8-hour [a]	143	122	129	147

[a] 4th Highest Values.

Highlands Ethanol requests that the monitoring data presented in Tables 6-9 and 6-12 satisfy the pre-construction monitoring criteria. The monitors are in areas representative of pre-construction conditions in Highlands County and of sufficient quality to be used to identify background air quality for interactive modeling. All of the data were collected from 2008 through 2010, satisfying the requirement that the data be current. Therefore, the three criteria established for using existing air quality measurements have been satisfied.

6.4 Class I Area Analysis

Class I areas are designated in 40 CFR Part 81, and are areas of special national or regional value from a natural, scenic, recreational, or historic perspective. Mandatory Federal Class I areas include the following areas in existence on August 7, 1977:

- International parks,
- National wilderness areas which exceed 5,000 acres in size,
- National memorial parks which exceed 5,000 acres in size, and
- National parks which exceed 6,000 acres in size.

These areas are administered by the National Park Service (NPS), the US Fish & Wildlife Service (USFWS), or the US Forest Service (USFS). These Federal Land Managers (FLMs) are responsible for evaluating a project's air quality impacts in the Class I areas and may make recommendations to the permitting agency to approve or deny permit applications. The FLMs are typically consulted prior to submittal of a permit application, which allows the FLM to assess the need for a Class I area impact analysis.

Class I area impact analyses were historically performed for proposed projects located within 100 kilometers of a Class I area, although this has been extended to 300 kilometers for some large projects. The analysis consists of:

- an increment analysis,
- a visibility impairment analysis, and
- an analysis of impacts on other air quality related values (AQRVs) such as impacts to flora and fauna, water, and cultural resources.

The closest Class I areas are the Everglades National Park (154 km) and Chassahowitzka Wilderness Area (216 km) in Florida. All other Class I areas are located at distances greater than 300 kilometers from the facility with the next closest being the Okefenokee Wilderness Area in Georgia (386 km).

An assessment of the potential impacts on Class I areas by the proposed project was performed using FLAG guidance. The results demonstrate that Class I area impacts would be insignificant and are consistent with the determination made in the previous analysis of this facility performed in 2009. The FLMs were notified at the time, and because potential facility emissions have decreased compared to the potential emissions allowed by the existing PSD permit, there is no requirement to notify the FLMs. Nevertheless, the conclusion confirms the previous decision by the FLMs to not require a full Class I area analysis. The total tons per year (tpy) of SO_2, NOx, PM_{10} and H_2SO_4 equals 229 tpy. The Everglades is the closest Class I area at 154 km. The FLAG calculation is: 229/154 which equals 1.5 and is less than the screening threshold of 10.

6.5 Additional Impacts Analysis

The Additional Impacts Analysis consists of an assessment of impacts resulting from community growth associated with the project, an assessment of visibility impacts resulting from the project, and impacts to local soils and vegetation resulting from the project.

6.5.1 Growth Analysis

Highlands Ethanol estimates that 200 new employees will be hired at the farm and the facility, which will increase permanent jobs within the community. There will be additional short-term local employment during the 18 to 24 month construction phase of the proposed project. Short-term employment is estimated at 600 to 800 workers.

6.5.1.1 Work Force

During the anticipated construction period associated with the proposed project, the construction jobs will be filled by local area workers, as well as workers currently located outside Highlands County. While supplemental, short-term labor is likely to relocate into the Highlands County area during the construction phase of the proposed project, Highlands Ethanol anticipates that the influx of temporary workers during the construction phase will have minimal effect on the environment, but will have a positive effect on the local economy.

For daily operation and maintenance of the proposed project, Highlands Ethanol anticipates that the required full time staff will be mostly comprised of current or future Highlands County area residents, and the project could result in a small increase in residential housing demand.

During the construction phase of the project, there will be a temporary increase in truck traffic. Once in operation, it is anticipated that approximately 100 vehicles per day will access the site from public roads (the balance will access the site from the farm). These include 60 employee vehicles, 26 delivery trucks, and 14 product trucks.

The resulting increase in indirect employment is not anticipated to significantly impact the air quality of the area because the increase represents a small fraction of the population of Highlands County (97,987 people estimated by the US Census Bureau for 2006). Thus, construction and operation of the proposed project will have a positive impact on the work force in Highlands County and the surrounding areas, but its net impact on the environment and to residential resource consumption is expected to be minimal.

6.5.1.2 Industry

Because much of the growth from the project will be filled by a relatively small number of new local labor and resources, Highlands Ethanol does not anticipate any significant corresponding commercial growth. Because the commercial and industrial growth resulting from the project is anticipated to be minimal, air quality impacts resulting from such commercial and industrial growth are expected to be minimal in the immediate area and its adjacent communities.

6.5.2 Visibility Impairment Analysis

The visibility impairment analysis addressed here is distinct from the analysis performed for Class I areas.

NPS guidance does address the need for visibility analysis in "Class II floor areas" although no specific guidance is provided that quantifies visibility impairment for these areas. Class II floor areas include the following areas in existence on August 7, 1977, that exceed 10,000 acres in size:

- National monuments,
- National primitive areas,
- National preserves,
- National recreational areas,
- National wild and scenic rivers,
- National wildlife refuges, and
- National lakeshores and seashores.

These Class II floor areas also include the following areas established after August 7, 1977 that exceed 10,000 acres in size:

- National parks, and
- National wilderness areas.

The only Class II floor area within 100 km of the proposed project is the Loxahatchee National Wildlife Refuge (92.6 km) near West Palm Beach, Florida. All other Class II floor areas are located at distances greater than 100 km from the proposed project with the next closest being the Big Cypress National Preserve in southern Florida (120 km). These distances are well beyond the significant impact area of the project, and as such visibility impacts in these areas are expected to be minimal.

6.5.3 Soils and Vegetation Analysis

Ambient air quality screening levels are provided for soils and vegetation in USEPA guidance (USEPA, 1980). Table 6-13 compares the predicted concentrations for those compounds that have predicted concentrations greater than their respective SILs for which there are relevant screening levels. USEPA has not published screening values for PM_{10}.

Table 6-13. Soils and Vegetation Screening Modeling – Project Only

Parameter	Averaging Period	AERMOD Predicted Conc. (μg/m³)	USEPA Screening Level (μg/m³)
SO_2	1-hour	55.9	917
	3-hour	106.4	786
	Annual	2.76	18
NO_2	4-hour	49.8	3760
	8-hour	44.8	3760
	1-month	7.6	564
	Annual	3.13	94

The predicted concentrations for SO_2 and NO_2 are less than the screening levels, thereby demonstrating that impacts to soils and vegetation will be negligible. AERMOD input and output files are provided on CDROM per the nomenclature described in Appendix F.

6.6 Ambient Air Quality Impact Analysis Conclusion

An ambient air quality impact analysis was conducted for the proposed project. Emission rates, exhaust parameters, and stack parameters were obtained or calculated, and wind-direction specific building dimensions were calculated with USEPA's BPIPPRM computer program. A modeling protocol was prepared that described the selected dispersion model, land use, receptor grids and meteorological data used.

The significant impact analysis was completed per USEPA guidance. Dispersion modeling was performed for simple terrain to determine the maximum impact operating scenario for the proposed boilers. The "100% load" operating scenario was selected for further analysis for all pollutants and averaging periods. The predicted concentrations for the selected operating scenarios were then compared to SILs. Predicted concentrations were less than SILs for CO and Pb, demonstrating compliance with NAAQS and allowable increments. Because predicted concentrations were less than SILs for CO and Pb, interactive source modeling was not required. In contrast, predicted concentrations of SO_2, PM_{10}, $PM_{2.5}$, and NO_2 were greater than SILs.

Interactive source modeling was performed for SO_2, PM_{10}, $PM_{2.5}$, and NO_2. Background air quality concentrations were identified based on data collected at monitoring sites. The interactive source analysis demonstrates that the project, when combined with the existing sources, will be in compliance with ambient air quality standards and ambient increment standards.

Highlands Ethanol is requesting an exemption from pre-construction monitoring requirements. Predicted concentrations of NO_2, CO, and Pb were less than SMCs. In the cases of SO_2, PM_{10}, and $PM_{2.5}$, existing data from nearby and adjacent counties were deemed to be representative of background air quality in Highlands County.

An assessment of the potential impacts on Class I areas by the proposed project was performed using FLAG guidance. The results demonstrate that Class I area impacts would be insignificant and are consistent with the determination made in the previous analysis of this facility performed in 2010. The FLMs were notified at the time, and because potential facility emissions have decreased compared to the potential emissions allowed by the existing PSD permit, there is no requirement to notify the FLMs. Nevertheless, the conclusion confirms the previous decision by the FLMs to not require a full Class I area analysis.

Finally, an additional impacts analysis was performed. Growth, visibility impairment, impacts to soils and vegetation, and air toxics were addressed. The analysis demonstrated that resulting impacts are minimal.

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APPENDIX A
Air Permit Application Forms

Department of Environmental Protection

Division of Air Resource Management

RECEIVED

AUG 08 2012

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.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: Highlands Ethanol, LLC	
2. Site Name: Highlands Ethanol	
3. Facility Identification Number: N/A	
4. Facility Location... Street Address or Other Locator: FL SR 70 and FL SR 721 City: East of Brighton County: Highlands Zip Code: 33857	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☐ Yes ☒ No

Application Contact

1. Application Contact Name: Kyle Kekeisen
2. Application Contact Mailing Address. Organization/Firm: BP Biofuels – Highlands Street Address: 2202 N. West Shore Blvd., Suite 200 City: Tampa State: FL Zip Code: 33607
3. Application Contact Telephone Numbers... Telephone: (813) 574 - 0622 ext. Fax: (813) 639 - 7573
4. Application Contact E-mail Address: Kyle.Kekeisen@bp.com

Application Processing Information (DEP Use)

1. Date of Receipt of Application: 8-8-12	3. PSD Number (if applicable):
2. Project Number(s): 0550061-003-AC	4. Siting Number (if applicable):

PSD 406A

APPLICATION INFORMATION

Purpose of Application

This application for air permit is being submitted to obtain: (Check one)

Air Construction Permit

[X] 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

Revisions to construction permit #0550061-001-AC/PSD-FL-406 for Highlands Ethanol, expiration date 12/31/14.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
EU001	Feedstock Receiving	AC1A	N/A
EU002	Obsolete, emissions now vented to RTO (formerly liquid/solid separation)	AC1A	N/A
EU003	RTO (includes fermentation, distillation, propagation, liquid/solid separation, product loadout)	AC1A	N/A
EU004	Solids separation, dewatering, and loadout	AC1A	N/A
EU005	Denaturant and Product Storage	AC1A	N/A
EU006	Obsolete, emissions now vented to RTO (formerly Product Loadout)	AC1A	N/A
EU007	Anaerobic Digestion, Biogas Conditioning, and Biogas Backup Flare	AC1A	N/A
EU008	Biomass Boiler	AC1A	N/A
EU009	Obsolete (formerly Biomass Boiler No. 2)	AC1A	N/A
EU010	Peaking Gas Boiler	AC1A	N/A
EU011	Cooling Tower	AC1A	N/A
EU012	Misc. Storage Silos	AC1A	N/A
EU013	Misc. Storage Tanks	AC1A	N/A
EU014	Emergency Generators	AC1A	N/A
EU015	Fire Pump	AC1A	N/A
EU016	Fugitive VOC Equipment Leaks	AC1A	N/A

Application Processing Fee

Check one: [X] Attached - Amount: $ 250 [ ] Not Applicable

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1. ~~Owne~~r/Authorized Representative Name : ANDREW VIVIAN

2. Owner/Authorized Representative Mailing Address...
   Organization/Firm: HIGHLANDS ETHANOL, LLC (BP BIOFUELS)
   Street Address: 2202 N. WESTSHORE BLVD, SUITE 200
   City: TAMPA State: FL Zip Code: 33626

3. Owner/Authorized Representative Telephone Numbers...
   Telephone: ( ) - ext. Fax: ( ) - 813 639 7550

4. Owner/Authorized Representative E-mail Address: andrew.vivian@bp.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] Date: 8/2/2012

APPLICATION INFORMATION

Application Responsible Official Certification (NOT APPLICABLE – AIR CONSTRUCTION PERMIT APPLICATION ONLY)

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): ☐ 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. ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively. ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official. ☐ The designated representative at an Acid Rain source or CAIR source.
3. Application Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
4. Application Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
5. Application Responsible Official E-mail Address:

6. Application Responsible Official Certification:

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.

_________________________ Signature

________________ Date

APPLICATION INFORMATION

Professional Engineer Certification

1.	Professional Engineer Name: Bradley S. Uhlmann Registration Number: 67917
2.	Professional Engineer Mailing Address Organization/Firm: AMEC Environment & Infrastructure Street Address: 1432 Pontiac Place SE City: Atlanta State: GA Zip Code: 30316
3.	Professional Engineer Telephone Numbers Telephone: (404) 963-1887 ext. Fax: (352) 333-6622
4.	Professional Engineer E-mail Address: brad.uhlmann@amec.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 ☒ X *, 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.

Signature: [signature] Date: 8/3/2012

(seal)

* Attach any exception to certification statement.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone 17 East (km) 493,200 North (km) 3,013,200		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
3. Governmental Facility Code: 0	4. Facility Status Code: C	5. Facility Major Group SIC Code: 28	6. Facility SIC(s): 2869
7. Facility Comment : Revisions to construction permit #0550061-001-AC/PSD-FL-406 for Highlands Ethanol, expiration date 12/31/14.			

Facility Contact

1. Facility Contact Name: Kyle Kekeisen
2. Facility Contact Mailing Address... Organization/Firm: BP Biofuels – Highlands Street Address: 2202 N. West Shore Blvd., Suite 200 City: Tampa State: FL Zip Code: 33607
3. Facility Contact Telephone Numbers: Telephone: (813) 574 - 0622 ext. Fax: (813) 639 - 7573
4. Facility Contact E-mail Address: Kyle.Kekeisen@bp.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: Same as application Responsible Official.
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: No synthetic restrictions on operations are being requested other than for the emergency engines and fire pump, which will be limited by 40 CFR 60, Subpart IIII.	

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
CO	A	
NO_X	A	
PM_{10}	A	
$PM_{2.5}$	A	
SO_2	A	
VOC	A	
NH_3	B	
Pb	B	
Total HAPs	B	
H001 - Acetaldehyde	B	
H006 - Acrolein	B	
H017 - Benzene	B	
H053 - Cumene	B	
H085 - Ethylbenzene	B	
H095 - Formaldehyde	B	
H104 - Hexane	B	

FACILITY INFORMATION

List of Pollutants Emitted by Facility (Continued)

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
H106 - Hydrochloric Acid	B	
H114 - Mercury	B	
H115 – Methanol	B	
H132 - Naphthalene	B	
H151 - Polycyclic Organic Matter	B	
H169 - Toluene	B	
H181 - 2,2,4-Trimethylpentane	B	
H186 - Xylenes	B	

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

7. Facility-Wide or Multi-Unit Emissions Cap Comment:
No facility-wide or multi-unit emissions caps are being requested.

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) [X] Attached, Document ID: Appendix C [ ] 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) [X] Attached, Document ID: Figure 2-2 [ ] 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) [X] Attached, Document ID: Section 5.3.2.6 [ ] Previously Submitted, Date:_________

Additional Requirements for Air Construction Permit Applications

1.	Area Map Showing Facility Location: [X] Attached, Document ID: Figure 2-1 [ ] Not Applicable (existing permitted facility)
2.	Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL): [X] Attached, Document ID: Section 2.0
3.	Rule Applicability Analysis: [X] Attached, Document ID: Section 4.0
4.	List of Exempt Emissions Units: [X] Attached, Document ID: Appendix H [ ] Not Applicable (no exempt units at facility)
5.	Fugitive Emissions Identification: [X] Attached, Document ID: Section 3.2 [ ] Not Applicable
6.	Air Quality Analysis (Rule 62-212.400(7), F.A.C.): [X] Attached, Document ID: Section 6 [ ] Not Applicable
7.	Source Impact Analysis (Rule 62-212.400(5), F.A.C.): [X] Attached, Document ID: Section 6 [ ] Not Applicable
8.	Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.): [X] Attached, Document ID: Section 6 [ ] Not Applicable
9.	Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.): [X] Attached, Document ID: Section 6.5 [ ] Not Applicable
10.	Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): [ ] Attached, Document ID:__________ [X] Not Applicable

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for FESOP Applications (NOT APPLICABLE)

1. List of Exempt Emissions Units: ☐ Attached, Document ID:__________ ☐ Not Applicable (no exempt units at facility)

Additional Requirements for Title V Air Operation Permit Applications (NOT APPLICABLE)

1. List of Insignificant Activities: (Required for initial/renewal applications only) ☐ 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) ☐ Attached, Document ID:__________ ☐ Not Applicable (revision application with no change in applicable requirements)
3. Compliance Report and Plan: (Required for all initial/revision/renewal applications) ☐ Attached, Document ID:__________ 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) ☐ Attached, Document ID:__________ ☐ Equipment/Activities Onsite but Not Required to be Individually Listed ☐ Not Applicable
5. Verification of Risk Management Plan Submission to EPA: (If applicable, required for initial/renewal applications only) ☐ Attached, Document ID:__________ ☐ Not Applicable
6. Requested Changes to Current Title V Air Operation Permit: ☐ 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: Acid Rain Part Application (DEP Form No. 62-210.900(1)(a)): ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________ ☒ Not Applicable (not an Acid Rain source) Phase II NO_X Averaging Plan (DEP Form No. 62-210.900(1)(a)1.): ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________ ☒ Not Applicable New Unit Exemption (DEP Form No. 62-210.900(1)(a)2.): ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________ ☒ Not Applicable
2.	CAIR Part (DEP Form No. 62-210.900(1)(b)): ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________ ☒ Not Applicable (not a CAIR source)

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.)

   [X] 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)

   [X] 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: Regenerative Thermal Oxidizer (RTO). The RTO handles emissions from liquid/solid separation, propagation, fermentation distillation, product storage shift tanks, and product loadout.

3. Emissions Unit Identification Number: EU003

4. Emissions Unit Status Code: C	5. Commence Construction Date: N/A	6. Initial Startup Date: N/A	7. Emissions Unit Major Group SIC Code: 28

8. Federal Program Applicability: (Check all that apply) N/A

   [ ] Acid Rain Unit

   [ ] CAIR Unit

9. Package Unit:
   Manufacturer: N/A Model Number: N/A

10. Generator Nameplate Rating: N/A MW

11. Emissions Unit Comment: N/A

Emissions Unit Control Equipment/Method: Control 1 of 1

1. Control Equipment/Method Description: Regenerative thermal oxidizer, destruction of process hydrocarbons by combustion	
2. Control Device or Method Code: 131	

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: 2,941 scf/hr		
2. Maximum Production Rate: 39,420,000 gal/yr of ethanol		
3. Maximum Heat Input Rate: 3 million Btu/hr (MMBtu/hr)		
4. Maximum Incineration Rate: pounds/hr N/A tons/day		
5. Requested Maximum Operating Schedule:	24 hours/day 52 weeks/year	7 days/week 8760 hours/year
6. Operating Capacity/Schedule Comment: RTO will use natural gas to combust hydrocarbons from process areas. RTO capacity is 3 MMBtu/hr and will destroy process VOCs with a destruction efficiency of 99%.		

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: RTO		2. Emission Point Type Code: 1
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: RTO stack		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A		
5. Discharge Type Code: V	6. Stack Height: 32.8 feet	7. Exit Diameter: 3 feet
8. Exit Temperature: 90 °F	9. Actual Volumetric Flow Rate: 20,000 acfm	10. Water Vapor: 5 %
11. Maximum Dry Standard Flow Rate: 20,000 dscfm		12. Nonstack Emission Point Height: N/A feet
13. Emission Point UTM Coordinates... Zone: 17 East (km): 493,219.07 North (km): 3,013,344		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): Ethanol production by fermentation. RTO will use natural gas to combust hydrocarbons from process areas, storage shift tanks and product loadout.		
2. Source Classification Code (SCC): 30125010	3. SCC Units: Tons	
4. Maximum Hourly Rate: 14.8 tons	5. Maximum Annual Rate: 129,771 tons	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: 0.02 gr/scf	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: 3
10. Segment Comment:		

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
PM10	**131**	**N/A**	**EL**
PM2.5	**131**	**N/A**	**EL**
SO2	**131**	**N/A**	**EL**
NOx	**131**	**N/A**	**EL**
CO	**131**	**N/A**	**EL**
VOC	**131**	**N/A**	**EL**
Total HAPs	**131**	**N/A**	**NS**

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_{10}	2. Total Percent Efficiency of Control: 99%
3. Potential Emissions: 0.0066 lb/hour 0.0289 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.0022 lb/MMBtu Reference: BACT	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment:	

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: $PM_{2.5}$	2. Total Percent Efficiency of Control: 99%
3. Potential Emissions: 0.0066 lb/hour 0.0289 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.0022 lb/MMBtu Reference: BACT	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment:	

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: SO_2	2. Total Percent Efficiency of Control: 99%
3. Potential Emissions: 0.0168 lb/hour 0.0735 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.0056 lb/MMBtu Reference: BACT	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment:	

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: NO_x	2. Total Percent Efficiency of Control: 99%
3. Potential Emissions: 0.105 lb/hour 0.460 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.035 lb/MMBtu Reference: BACT	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment:	

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: 99%
3. Potential Emissions: 0.111 lb/hour 0.486 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.037 lb/MMBtu Reference: BACT	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment:	

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: 99%
3. Potential Emissions: 8.92 lb/hour 21.4 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.0014 lb/MMBtu Reference: BACT	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment:	

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: Total HAPs	2. Total Percent Efficiency of Control: 99%
3. Potential Emissions: 2.27 lb/hour 8.69 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: varies by HAP Reference: ASPEN model results; AP-42 Section 1.4 Natural Gas Combustion, July 1998	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
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 7

1. Basis for Allowable Emissions Code: Rule	2. Future Effective Date of Allowable Emissions: Upon permit revision
3. Allowable Emissions and Units: 99% control	4. Equivalent Allowable Emissions: 0.0066 lb/hour 0.0289 tons/year
5. Method of Compliance: Method 25 or 25A compliance test	
6. Allowable Emissions Comment (Description of Operating Method): Proposed PM10 BACT Emission Limit per 62-212.400(10) F.A.C.	

Allowable Emissions Allowable Emissions 2_ of 7__

1. Basis for Allowable Emissions Code: Rule	2. Future Effective Date of Allowable Emissions: Upon permit revision
3. Allowable Emissions and Units: 99% control	4. Equivalent Allowable Emissions: 0.0066 lb/hour 0.0289 tons/year
5. Method of Compliance: Method 25 or 25A compliance test	
6. Allowable Emissions Comment (Description of Operating Method): Proposed PM2.5 BACT Emission Limit per 62-212.400(10) F.A.C.	

Allowable Emissions Allowable Emissions 3_ of 7__

1. Basis for Allowable Emissions Code: Rule	2. Future Effective Date of Allowable Emissions: Upon permit revision
3. Allowable Emissions and Units: 99% control	4. Equivalent Allowable Emissions: 0.0168 lb/hour 0.0735 tons/year
5. Method of Compliance: Method 25 or 25A compliance test	
6. Allowable Emissions Comment (Description of Operating Method): Proposed SO2 BACT Emission Limit per 62-212.400(10) F.A.C.	

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 4 of 7

1. Basis for Allowable Emissions Code: Rule	2. Future Effective Date of Allowable Emissions: Upon permit revision
3. Allowable Emissions and Units: 99% control	4. Equivalent Allowable Emissions: 0.105 lb/hour 0.460 tons/year
5. Method of Compliance: Method 25 or 25A compliance test	
6. Allowable Emissions Comment (Description of Operating Method): Proposed NOx BACT Emission Limit per 62-212.400(10) F.A.C.	

Allowable Emissions Allowable Emissions 5_ of 7__

1. Basis for Allowable Emissions Code: Rule	2. Future Effective Date of Allowable Emissions: Upon permit revision
3. Allowable Emissions and Units: 99% control	4. Equivalent Allowable Emissions: 0.111 lb/hour 0.486 tons/year
5. Method of Compliance: Method 25 or 25A compliance test	
6. Allowable Emissions Comment (Description of Operating Method): Proposed CO BACT Emission Limit per 62-212.400(10) F.A.C.	

Allowable Emissions Allowable Emissions 6_ of 7__

1. Basis for Allowable Emissions Code: Rule	2. Future Effective Date of Allowable Emissions: Upon permit revision
3. Allowable Emissions and Units: 99% control	4. Equivalent Allowable Emissions: 8.92 lb/hour 21.44 tons/year
5. Method of Compliance: Method 25 or 25A compliance test	
6. Allowable Emissions Comment (Description of Operating Method): Proposed VOC BACT Emission Limit per 62-212.400(10) F.A.C.	

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 7 of 7

1. Basis for Allowable Emissions Code: Rule	2. Future Effective Date of Allowable Emissions: Upon permit revision
3. Allowable Emissions and Units: 99% control	4. Equivalent Allowable Emissions: 2.27 lb/hour 8.69 tons/year
5. Method of Compliance: Method 25 or 25A compliance test	
6. Allowable Emissions Comment (Description of Operating Method): Proposed HAPs BACT Emission Limit per 62-212.400(10) F.A.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):	

G. *VISIBLE EMISSIONS INFORMATION*

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation. N/A

Visible Emissions Limitation: Visible Emissions Limitation __of ____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % 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: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % 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. N/A

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)
[x] Attached, Document ID: Figure 2-2 [ ] 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: N/A [ ] 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)
[x] Attached, Document ID: Section 5 [ ] 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 ________
[x] 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 ________
[x] 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: ________
[x] To be Submitted, Date (if known): After start-up
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: ________ [x] 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)): [x] Attached, Document ID: Section 5 [ ] Not Applicable
2.	Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): [x] Attached, Document ID: Section 6 [ ] Not Applicable
3.	Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) [ ] Attached, Document ID:__________ [x] Not Applicable

Additional Requirements for Title V Air Operation Permit Applications N/A

1.	Identification of Applicable Requirements: [ ] Attached, Document ID: __________
2.	Compliance Assurance Monitoring: [ ] Attached, Document ID: __________ [ ] Not Applicable
3.	Alternative Methods of Operation: [ ] Attached, Document ID: __________ [ ] Not Applicable
4.	Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID: __________ [ ] Not Applicable

Additional Requirements Comment

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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.)

   [X] 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.

   [X] 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: Solids Separation, dewatering, and loadout. Stillage cake is removed from the celluosic beer stripper distillation column, dewatered to remove some of the water fraction, and conveyed to the biomass boiler for use as a fuel.

3. Emissions Unit Identification Number: EU004

4. Emissions Unit Status Code: C	5. Commence Construction Date: N/A	6. Initial Startup Date: N/A	7. Emissions Unit Major Group SIC Code: 28

8. Federal Program Applicability: (Check all that apply) N/A

   [ ] Acid Rain Unit

   [ ] CAIR Unit

9. Package Unit:
   Manufacturer: N/A   Model Number: N/A

10. Generator Nameplate Rating: N/A MW

11. Emissions Unit Comment: Stillage is removed from the beer stripper distillation column, centrifuged to remove some of the water fraction, and conveyed to the biomass boiler. The stillage will not be dried. Stillage will be generated at a rate of 11 dry tons per hour and will consist primarily of lignin fibers and secondarily of unhydrolyzed cellulose fibers with a moisture content between 50 and 60 percent. Handling will be performed entirely within a closed system except for the conveyor. Based on the consistency and moisture content of the material, PM emissions are expected to be negligible. VOC emissions will occur from the evaporation of organics dissolved in the water fraction and escaping the conveyor as fugitive emissions.

Emissions Unit Control Equipment/Method: Control 1 of 1

1. Control Equipment/Method Description: None
2. Control Device or Method Code: N/A

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: 11 dry tons per hour of stillage		
2. Maximum Production Rate: 39,420,000 gal/yr of ethanol		
3. Maximum Heat Input Rate: N/A million Btu/hr		
4. Maximum Incineration Rate: N/A pounds/hr N/A tons/day		
5. Requested Maximum Operating Schedule:	24 hours/day 52 weeks/year	7 days/week 8,760 hours/year
6. Operating Capacity/Schedule Comment: N/A		

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: Stillage Loadout	2. Emission Point Type Code: 4
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: N/A	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A	

5. Discharge Type Code: P	6. Stack Height: N/A feet	7. Exit Diameter: N/A feet
8. Exit Temperature: N/A °F	9. Actual Volumetric Flow Rate: N/A acfm	10. Water Vapor: N/A %

11. Maximum Dry Standard Flow Rate: N/A dscfm	12. Nonstack Emission Point Height: N/A feet
13. Emission Point UTM Coordinates... Zone: 17 East (km): N/A North (km): N/A	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: N/A	

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): General Processes – Storage and Transfer		
2. Source Classification Code (SCC): 30183001	3. SCC Units: Tons	
4. Maximum Hourly Rate: 11	5. Maximum Annual Rate: 96,360	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: N/A	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: N/A
10. Segment Comment: Stillage cake will be removed from the beer stripper distillation column, dewatered to remove some of the water fraction, and conveyed to the biomass boiler for use as fuel.		

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	N/A	N/A	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.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 1.9 lb/hour 8.4 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.0001421 lb VOC per gallon of ethanol produced. Reference: Initial Study/Environmental Checklist for the Pacific Ethanol Facility, San Joaquin Valley Unified Air Pollution Control District, January 29, 2004.	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
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: Upon Permit Issuance
3. Allowable Emissions and Units: 1.9 lb/hr; 8.4 tons/yr	4. Equivalent Allowable Emissions: 1.9 lb/hour 8.4 tons/year
5. Method of Compliance: Material throughput records and emission calculations	
6. Allowable Emissions Comment (Description of Operating Method): Proposed VOC BACT Emission Limit per 62-212.400(10) F.A.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):	

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation. N/A

Visible Emissions Limitation: Visible Emissions Limitation __ of ____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % 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: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % 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. N/A

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)
   [X] Attached, Document ID: Figure 2-2 [ ] 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: NA [ ] 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)
   [X] Attached, Document ID: Section 5 [ ] 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 ___________
   [X] 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 ___________
   [X] 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: ___________

   [X] To be Submitted, Date (if known): : ________
   Test Date(s)/Pollutant(s) Tested: After Start-Up

   [ ] 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: ___________ [X] 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)): [x] Attached, Document ID: Section 5 [ ] Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): [x] Attached, Document ID: Section 6 [ ] Not Applicable
3. Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) [ ] Attached, Document ID:__________ [x] Not Applicable

Additional Requirements for Title V Air Operation Permit Applications (N/A)

1. Identification of Applicable Requirements: [ ] Attached, Document ID: __________
2. Compliance Assurance Monitoring: [ ] Attached, Document ID: __________ [ ] Not Applicable
3. Alternative Methods of Operation: [ ] Attached, Document ID: __________ [ ] Not Applicable
4. Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID: __________ [ ] Not Applicable

Additional Requirements Comment

N/A

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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.)

   [X] 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)

   [X] 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 and Denaturant Storage Tanks. The facility includes 3 product shift tanks, 1 product storage tank, and 1 denaturant (gasoline) tank.

3. Emissions Unit Identification Number: EU005

4. Emissions Unit Status Code: C	5. Commence Construction Date: N/A	6. Initial Startup Date: N/A	7. Emissions Unit Major Group SIC Code: 28

8. Federal Program Applicability: (Check all that apply) N/A

   [ ] Acid Rain Unit

   [ ] CAIR Unit

9. Package Unit:
   Manufacturer: N/A Model Number: N/A

10. Generator Nameplate Rating: N/A MW

11. Emissions Unit Comment: N/A

Emissions Unit Control Equipment/Method: Control 1 of 2

1. Control Equipment/Method Description: Internal Floating Roofs in product and denaturant storage tanks.
2. Control Device or Method Code: 091

Emissions Unit Control Equipment/Method: Control 2 of 2

1. Control Equipment/Method Description: Vertical fixed roofs vented to ethanol recovery absorber for product shift tanks, followed by RTO.
2. Control Device or Method Code: 131

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:	39,420,000 gal/yr of ethanol 41,490,000 gal/yr of E95	
2. Maximum Production Rate: N/A		
3. Maximum Heat Input Rate: N/A		
4. Maximum Incineration Rate:	N/A pounds/hr N/A tons/day	
5. Requested Maximum Operating Schedule:	24 hours/day 52 weeks/year	7 days/week 8760 hours/year
6. Operating Capacity/Schedule Comment: N/A		

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 Storage	2. Emission Point Type Code: 3	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: N/A		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A		
5. Discharge Type Code: P	6. Stack Height: 52 feet	7. Exit Diameter: 0.25 feet
8. Exit Temperature: 77 °F	9. Actual Volumetric Flow Rate: N/A	10. Water Vapor: N/A
11. Maximum Dry Standard Flow Rate: N/A dscfm	12. Nonstack Emission Point Height: N/A feet	
13. Emission Point UTM Coordinates... Zone: 17 East (km): 493,359.26 North (km): 3,013,064.49	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: Emission point data provided correspond to Product Storage Tank, which is the largest tank.		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): VOC emissions from product storage and denaturant tanks.		
2. Source Classification Code (SCC): 40799997	3. SCC Units: 1000 Gallons Throughput	
4. Maximum Hourly Rate: 0.28 lb/hr	5. Maximum Annual Rate: 1.18 tons/yr	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: N/A	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: N/A
10. Segment Comment: One 472,000-gallon product storage tank and one 13,500-gallon denaturant tank.		

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	091	131	EL
HAPS*	091	N/A	NS
H017	091	N/A	NS
H085	091	N/A	NS
H104	091	N/A	NS
H053	091	N/A	NS
H169	091	N/A	NS
H181	091	N/A	NS

*** Although the facility is not major for HAPs, the HAPs emitted are provided in Section E and emissions of total HAPs are provided in Section F1 for informational purposes.**

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: 99%
3. Potential Emissions: 0.28 lb/hour 1.18 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: Refer to the ethanol storage and denaturant storage emissions calculations in Appendix B. Reference: USEPA TANKS 4.09d Program	7. Emissions Method Code: 3 (TANKS is based on AP-42)
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment: Maximum short-term emissions are based on July TANKS calculations.	

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: N/A
3. Potential Emissions: 0.017 lb/hour 0.069 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: Refer to the TANKS 4.09d emissions calculations in Appendix B. Reference: USEPA TANKS 4.09d Program.	7. Emissions Method Code: 3 (TANKS is based on AP-42)
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment: Maximum short-term emissions are based on July TANKS calculations.	

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: Upon permit revision
3. Allowable Emissions and Units: Use of internal floating roof tanks & RTO	4. Equivalent Allowable Emissions: 0.28 lb/hour 1.18 tons/year
5. Method of Compliance: Equipment design	
6. Allowable Emissions Comment (Description of Operating Method): Proposed VOC BACT Emission Limit per 62-212.400(10) F.A.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):	

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation. N/A

Visible Emissions Limitation: Visible Emissions Limitation __of ____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % 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: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % 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. N/A

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) [x] Attached, Document ID: Figure 2-2 [ ] 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: N/A [ ] 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) [X] Attached, Document ID: Section 5 [ ] 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 ______ [X] 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 ______ [X] 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: ______ [X] To be Submitted, Date (if known): After start-up 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: ______ [X] 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)): [x] Attached, Document ID: Section 5 [ ] Not Applicable
2.	Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): [X] Attached, Document ID: Section 6 [ ] Not Applicable
3.	Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) [ ] Attached, Document ID:__________ [X] Not Applicable

Additional Requirements for Title V Air Operation Permit Applications N/A

1.	Identification of Applicable Requirements: [ ] Attached, Document ID: __________
2.	Compliance Assurance Monitoring: [ ] Attached, Document ID: __________ [ ] Not Applicable
3.	Alternative Methods of Operation: [ ] Attached, Document ID: __________ [ ] Not Applicable
4.	Alternative Modes of Operation (Emissions Trading): [ ] 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.)

   [X] 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)

   [X] 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: Biogas Backup Flare. Biogas produced by anaerobic digestion will generally be combusted in the biomass boiler. A back up flare with a rated capacity of 100 MMBtu/hr will be used when the biomass boiler is not in operation. Biogas will be conditioned by an H_2S scrubber prior to flare.

3. Emissions Unit Identification Number: EU007

4. Emissions Unit Status Code: C	5. Commence Construction Date: N/A	6. Initial Startup Date: N/A	7. Emissions Unit Major Group SIC Code: 28

8. Federal Program Applicability: (Check all that apply) N/A

   [ ] Acid Rain Unit

   [ ] CAIR Unit

9. Package Unit:N/A
   Manufacturer: Model Number:

10. Generator Nameplate Rating: N/A MW

11. Emissions Unit Comment: N/A

Emissions Unit Control Equipment/Method: Control 1 of 3

1. Control Equipment/Method Description: Combustion in the biomass boiler	
2. Control Device or Method Code: 024	

Emissions Unit Control Equipment/Method: Control 2 of 3

1. Control Equipment/Method Description: Backup Flare	
2. Control Device or Method Code: 023	

Emissions Unit Control Equipment/Method: Control 3 of 3

1. Control Equipment/Method Description: H_2S scrubber prior to flare	
2. Control Device or Method Code: 013	

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: N/A		
2. Maximum Production Rate: N/A		
3. Maximum Heat Input Rate: Pilot = 0.18 MMBtu/hr; Flare = 100 MMBtu/hr		
4. Maximum Incineration Rate: N/A pounds/hr N/A tons/day		
5. Requested Maximum Operating Schedule:	24 hours/day 52 weeks/year	7 days/week 8760 hours/year
6. Operating Capacity/Schedule Comment: Flare will be used as back-up when the biomass boiler is not available.		

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: Backup flare		2. Emission Point Type Code: 1
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: N/A		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A		
5. Discharge Type Code: V	6. Stack Height: TBD	7. Exit Diameter: TBD
8. Exit Temperature: TBD °F	9. Actual Volumetric Flow Rate: TBD acfm	10. Water Vapor: TBD
11. Maximum Dry Standard Flow Rate: TBD dscfm		12. Nonstack Emission Point Height: N/A feet
13. Emission Point UTM Coordinates... Zone: 17 East (km): 493377.85 North (km): 3013586.15		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: Stack parameters provided are for the flare. Biomass boiler stack information is provided EU008.		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): 0.18 MMBtu/hr of Natural Gas (pilot)		
2. Source Classification Code (SCC): 10200602	3. SCC Units: Million Cubic Feet	
4. Maximum Hourly Rate: 0.043	5. Maximum Annual Rate: 378	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: N/A	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: 1,020
10. Segment Comment: Emissions from the natural gas associated with the flare. VOC emissions from treatment of biogas are accounted for in the biomass boiler emission rate in EU008.		

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*	024	N/A	NS
PM_{10}	024	N/A	NS
$PM_{2.5}$	024	N/A	NS
SO_2	024	N/A	NS
NO_X	024	N/A	NS
CO	024	N/A	NS

* VOC emissions are for combustion of natural gas in the flare. VOC emissions from treatment of biogas are accounted for in the biomass boiler emission rate in Section 5 of 12.

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: 14.0 lb/hour 0.11 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.14 lb THC per MMBtu Reference: EPA AP-42, Section 13.5, Industrial Flares, January 1995.	7. Emissions Method Code: 3
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment:	

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_{10}	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 0.24 lb/hour 0.002 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.0024 lb PM per MMBtu Reference: EPA AP-42, Section 13.5, Industrial Flares, January 1995.	7. Emissions Method Code: 3
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment:	

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: $PM_{2.5}$	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 0.24 lb/hour 0.002 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.0024 lb PM per MMBtu Reference: EPA AP-42, Section 13.5, Industrial Flares, January 1995.	7. Emissions Method Code: 3
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment:	

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: SO_2	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 10 lb/hour 0.0005 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.00059 lb SO_2 per MMBtu Reference: EPA AP-42, Section 13.5, Industrial Flares, January 1995.	7. Emissions Method Code: 3
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment:	

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: NO_X	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 6.8 lb/hour 0.055 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.068 lb NO_X per MMBtu Reference: EPA AP-42, Section 13.5, Industrial Flares, January 1995.	7. Emissions Method Code: 3
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment:	

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: N/A
3. Potential Emissions: 37 lb/hour 0.30 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.37 lb CO per MMBtu Reference: EPA AP-42, Section 13.5, Industrial Flares, January 1995.	7. Emissions Method Code: 3
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
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 2

1. Basis for Allowable Emissions Code: Rule	2. Future Effective Date of Allowable Emissions: Upon permit revision
3. Allowable Emissions and Units: 98% Control (for flare)	4. Equivalent Allowable Emissions: N/A lb/hour N/A tons/year (VOC emissions from biogas combustion are included in biomass boiler emissions in Section 5 of 12)
5. Method of Compliance: Equipment design	
6. Allowable Emissions Comment (Description of Operating Method): Proposed VOC BACT Emission Limit per 62-212.400(10) F.A.C.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: Rule	2. Future Effective Date of Allowable Emissions: Upon permit revision
3. Allowable Emissions and Units: 98% sulfur removal	4. Equivalent Allowable Emissions: N/A lb/hour N/A tons/year
5. Method of Compliance: Equipment design	
6. Allowable Emissions Comment (Description of Operating Method): BACT for SO_2 emissions for the biogas backup flare is 98 percent sulfur removal via a packed bed wet scrubber with chemical addition.	

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: N/A % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: EPA Method 9	
5. Visible Emissions Comment: VE limitation required by 62-296.320(4)(b) F.A.C. (General Visible Emission Standard)	

Visible Emissions Limitation: Visible Emissions Limitation __ of ____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % 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. N/A

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)
   [x] Attached, Document ID: Figure 2-2 [ ] 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: N/A [ ] 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)
   [X] Attached, Document ID: Section 5 [ ] 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 ____
   [X] 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 ____
   [X] 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: ____
   [X] To be Submitted, Date (if known): After start-up
   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: ____ [X] 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)): [x] Attached, Document ID: Section 5 [ ] Not Applicable
2.	Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): [x] Attached, Document ID: Section 6 [ ] Not Applicable
3.	Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) [ ] Attached, Document ID:__________ [x] Not Applicable

Additional Requirements for Title V Air Operation Permit Applications N/A

1.	Identification of Applicable Requirements: [ ] Attached, Document ID: __________
2.	Compliance Assurance Monitoring: [ ] Attached, Document ID: __________ [ ] Not Applicable
3.	Alternative Methods of Operation: [ ] Attached, Document ID: __________ [ ] Not Applicable
4.	Alternative Modes of Operation (Emissions Trading): [ ] 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.)

   [X] 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)

   [X] 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 with fluidized bed will burn stillage cake, biosolids, biogas, and natural gas as fuel with natural gas for startups and flame stabilization. The boiler will be equipped with a fabric filter to control PM emissions, selective non-catalytic reduction (SNCR) to control NO_X emissions, and limestone injection and a scrubber to control SO_2 emissions. Good combustion practices will be used to minimize CO and VOC emissions.

3. Emissions Unit Identification Number: EU008

4. Emissions Unit Status Code: C	5. Commence Construction Date: N/A	6. Initial Startup Date: N/A	7. Emissions Unit Major Group SIC Code: 28

8. Federal Program Applicability: (Check all that apply) N/A

   [ ] Acid Rain Unit

   [ ] CAIR Unit

9. Package Unit:
   Manufacturer: TBD Model Number: TBD

10. Generator Nameplate Rating: N/A MW

11. Emissions Unit Comment: N/A

Emissions Unit Control Equipment/Method: Control 1 of 4

1. Control Equipment/Method Description: Fabric Filter – High Temperature (>250 °F)	
2. Control Device or Method Code: 016	

Emissions Unit Control Equipment/Method: Control 2 of 4

1. Control Equipment/Method Description: Selective Noncatalytic Reduction for NO_X	
2. Control Device or Method Code: 107	

Emissions Unit Control Equipment/Method: Control 3 of 4

1. Control Equipment/Method Description: Dry Limestone Injection	
2. Control Device or Method Code: 041	

Emissions Unit Control Equipment/Method: Control 4 of 4

1. Control Equipment/Method Description: Dry scrubber	
2. Control Device or Method Code: 119	

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: N/A		
2. Maximum Production Rate: N/A		
3. Maximum Heat Input Rate: 270 MMBtu/hr		
4. Maximum Incineration Rate: N/A pounds/hr N/A tons/day		
5. Requested Maximum Operating Schedule:	24 hours/day 52 weeks/year	7 days/week 8760 hours/year
6. Operating Capacity/Schedule Comment: Stillage cake + Biosolids capacity = 170 MMBtu/hr Biogas capacity = 100 MMBtu/hr Natural gas capacity = 250 MMBtu/hr Total maximum boiler capacity = 270 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: Biomass Boiler		2. Emission Point Type Code: 3
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: Stack of boiler		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A		
5. Discharge Type Code: V	6. Stack Height: 130 ft	7. Exit Diameter: 7 ft
8. Exit Temperature: 175 °F	9. Actual Volumetric Flow Rate: 75,073 acfm	10. Water Vapor: unknown
11. Maximum Dry Standard Flow Rate: 9,600 dscfm /MMBtu		12. Nonstack Emission Point Height: N/A feet
13. Emission Point UTM Coordinates... Zone: 17 East (km): 493081.61 North (km): 3013427.78		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): Fluidized bed combustion boiler		
2. Source Classification Code (SCC): 10200912	3. SCC Units: Dry tons (of biomass)	
4. Maximum Hourly Rate: 11	5. Maximum Annual Rate: 96,360	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: 4.4%, Variable	8. Maximum % Ash: 7%, Variable	9. Million Btu per SCC Unit: 16.8
10. Segment Comment: N/A		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): Natural Gas >100 MMBtu/hr		
2. Source Classification Code (SCC): 10200601	3. SCC Units: Million Cubic Feet	
4. Maximum Hourly Rate: 0.245	5. Maximum Annual Rate: 2,150	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: N/A	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: 1,020
10. Segment Comment: N/A		

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_{10}	016	N/A	EL
$PM_{2.5}$	016	N/A	EL
SO_2	041	N/A	EL
NO_X	107	N/A	EL
CO	N/A	N/A	EL
VOC	N/A	N/A	EL
NH_3	N/A	N/A	EL
PB	N/A	N/A	NS
HAPS*	N/A	N/A	NS
H106	N/A	N/A	NS
H114	N/A	N/A	NS
H151	N/A	N/A	NS

*** Although the facility is not major for HAPs, the HAPs emitted are provided in Section E and emissions of total and individual HAPs are provided in Section F1 for informational purposes. Mercury is included specifically at the request of FDEP.**

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_{10}	2. Total Percent Efficiency of Control: 99+%
3. Potential Emissions: 13.5 lb/hour 59.1 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.01 lb PM_{10} per MMBtu (filterable PM_{10}) Reference: Emission factor based on proposed BACT emission limit.	7. Emissions Method Code: 0
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment:	

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: $PM_{2.5}$	2. Total Percent Efficiency of Control: 99+%
3. Potential Emissions: 13.5 lb/hour 59.1 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.01 lb $PM_{2.5}$ per MMBtu (filterable $PM_{2.5}$) Reference: Emission factor based on proposed BACT emission limit.	7. Emissions Method Code: 0
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment:	

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: SO_2	2. Total Percent Efficiency of Control: 85-95%
3. Potential Emissions: 16.2 lb/hour 71.0 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor 0.06 lb SO_2 per MMBtu (30-day rolling average) 0.12 lb SO_2 per MMBtu (24-hour rolling average) 0.14 lb SO_2 per MMBtu (3-hour block average) Reference: Emission factor based on proposed BACT emission limit.	7. Emissions Method Code: 0
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment:	

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: NO_X	2. Total Percent Efficiency of Control: 45-65%
3. Potential Emissions: 21.6 lb/hour 95 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.08 lb NO_X per MMBtu (30-day rolling average) Reference: Emission factor based on proposed BACT emission limit.	7. Emissions Method Code: 0
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment:	

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: N/A
3. Potential Emissions: 27.0 lb/hour 118 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.1 lb CO per MMBtu (30-day rolling average) Reference: Emission factor based on proposed BACT emission limit.	7. Emissions Method Code: 0
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment:	

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: N/A
3. Potential Emissions: 1.35 lb/hour 5.91 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.005 lb VOC per MMBtu Reference: Emission factor based on proposed BACT emission limit.	7. Emissions Method Code: 0
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment:	

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: NH_3	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 3.44 lb/hour 15.1 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.013 lb/MMBtu Reference: Emission factor based on proposed ammonia slip for SNCR to meet NO_X BACT emission limit.	7. Emissions Method Code: 0
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment: N/A	

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 (Lead)	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 0.013 lb/hour 0.0568 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.000048 lb per MMBtu Reference: Pb emission factors are not available for stillage cake. Emission factors from AP-42 Section 1.8, Bagasse Combustion In Sugar Mills (Oct. 1996), were used as a surrogate.	7. Emissions Method Code: 4
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment: N/A	

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: N/A
3. Potential Emissions: 1.5 lb/hour 6.57 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: See emissions inventory calculations in Appendix B for pollutant-specific emission factors. Reference: HAP emission factors are not available for stillage cake. Emission factors from AP-42 Section 1.8, Bagasse Combustion In Sugar Mills (Oct. 1996), were used as a surrogate except for HCl and Hg, which were based on testing of feedstock.	7. Emissions Method Code: 4
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment: N/A	

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: H106 (Hydrochloric Acid)	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 1.46 lb/hour 6.39 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.0054 lb per MMBtu Reference: HCl emission factor is based on testing of feedstock.	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment: N/A	

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: H114 (Mercury)	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 0.0027 lb/hour 0.0118 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 1E-05 lb per MMBtu Reference: Hg emission factor is based on testing of feedstock.	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment: N/A	

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: H151 (Polycyclic Organic Matter)	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 0.0386 lb/hour 0.169 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.000143 lb per MMBtu Reference: HAP emission factors are not available for stillage cake. Emission factors from AP-42 Section 1.8, Bagasse Combustion In Sugar Mills (Oct. 1996), were used as a surrogate.	7. Emissions Method Code: 4
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment: N/A	

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 7

1. Basis for Allowable Emissions Code: Rule	2. Future Effective Date of Allowable Emissions: Upon permit revision
3. Allowable Emissions and Units: 0.01 lb/MMBtu (filterable)	4. Equivalent Allowable Emissions: 13.5 lb/hour 59.1 tons/year
5. Method of Compliance: EPA Method 5 compliance test	
6. Allowable Emissions Comment (Description of Operating Method): Proposed PM_{10} BACT Emission Limit per 62-212.400(10) F.A.C.	

Allowable Emissions Allowable Emissions 2 of 7

1. Basis for Allowable Emissions Code: Rule	2. Future Effective Date of Allowable Emissions: Upon permit revision
3. Allowable Emissions and Units: 0.01 lb/MMBtu (filterable)	4. Equivalent Allowable Emissions: 13.5 lb/hour 59.1 tons/year
5. Method of Compliance: EPA Method 5 compliance test	
6. Allowable Emissions Comment (Description of Operating Method): Proposed $PM_{2.5}$ BACT Emission Limit per 62-212.400(10) F.A.C.	

Allowable Emissions Allowable Emissions 3 of 7

1. Basis for Allowable Emissions Code: Rule	2. Future Effective Date of Allowable Emissions: Upon permit revision
3. Allowable Emissions and Units: 0.06 lb/MMBtu (30-day rolling average)	4. Equivalent Allowable Emissions: 16.2 lb/hour 71.0 tons/year
5. Method of Compliance: CEMS	
6. Allowable Emissions Comment (Description of Operating Method): Proposed SO_2 BACT Emission Limit per 62-212.400(10) F.A.C.	

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 4 of 7

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: Upon Permit Issuance
3. Allowable Emissions and Units: 0.08 lb/MMBtu	4. Equivalent Allowable Emissions: 21.6 lb/hour 95 tons/year
5. Method of Compliance: CEMS	
6. Allowable Emissions Comment (Description of Operating Method): Proposed NO_X BACT Emission Limit per 62-212.400(10) F.A.C.	

Allowable Emissions Allowable Emissions 5 of 7

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: Upon Permit Issuance
3. Allowable Emissions and Units: 0.1 lb/MMBtu (30-day rolling average)	4. Equivalent Allowable Emissions: 27.0 lb/hour 118 tons/year
5. Method of Compliance: CEMS	
6. Allowable Emissions Comment (Description of Operating Method): Proposed CO BACT Emission Limit per 62-212.400(10) F.A.C.	

Allowable Emissions Allowable Emissions 6 of 7

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: Upon Permit Issuance
3. Allowable Emissions and Units: 0.005 lb/MMBtu	4. Equivalent Allowable Emissions: 1.35 lb/hour 5.91 tons/year
5. Method of Compliance: EPA Method 25 or 25A compliance test	
6. Allowable Emissions Comment (Description of Operating Method): Proposed VOC BACT Emission Limit per 62-212.400(10) F.A.C.	

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 7 of 7

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: Upon Permit Issuance
3. Allowable Emissions and Units: 0.013 lbs/MMBtu (20 ppm)	4. Equivalent Allowable Emissions: 3.44 lb/hour 15.1 tons/year
5. Method of Compliance: TBD	
6. Allowable Emissions Comment (Description of Operating Method): Proposed NH_3 slip for SNCR to meet proposed NO_X BACT Emission Limit per 62-212.400(10) F.A.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):	

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 3

1. Visible Emissions Subtype: VE20	2. Basis for Allowable Opacity: [x] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: 20 % Exceptional Conditions: 27 % Maximum Period of Excess Opacity Allowed: 6 min/hour OR Normal Conditions: 20 % Exceptional Conditions: 40 % Maximum Period of Excess Opacity Allowed: 2 min/hour	
4. Method of Compliance: COMS	
5. Visible Emissions Comment: VE limitation required by 62-296.406 F.A.C. (Fossil Fuel Steam Generators with less than 250 MMBtu/hr Heat Input, New and Existing Emission Units) when boiler is combusting natural gas.	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 3

1. Visible Emissions Subtype: VE30	2. Basis for Allowable Opacity: [x] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: 30 % Exceptional Conditions: 40 % Maximum Period of Excess Opacity Allowed: 2 min/hour	
4. Method of Compliance: COMS	
5. Visible Emissions Comment: VE limitation required by 62-296.410 F.A.C. (Carbonaceous Fuel Burning Equipment) when boiler is combusting biomass.	

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 3 of 3

1. Visible Emissions Subtype: VE20	2. Basis for Allowable Opacity: [x] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: 20 % Exceptional Conditions: N/A % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: COMS	
5. Visible Emissions Comment: VE limitation required by 62-296.320(4)(b) F.A.C. (General Visible Emission Standard)	

Visible Emissions Limitation: Visible Emissions Limitation _ of _

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: Exceptional Conditions: 40 % Maximum Period of Excess Opacity Allowed: 2 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 1 of 5

1. Parameter Code: EM	2. Pollutant(s): NO_X
3. CMS Requirement:	[x] Rule [ ] Other
4. Monitor Information... Manufacturer: TBD Model Number: TBD	Serial Number: TBD
5. Installation Date: After Permit Issuance	6. Performance Specification Test Date: TBD
7. Continuous Monitor Comment: CEMS is required by 40 CFR 60.48b (Subpart Db) and proposed for 62-212.400(10) F.A.C (BACT)	

Continuous Monitoring System: Continuous Monitor 2 of 5

1. Parameter Code: EM	2. Pollutant(s): SO_2
3. CMS Requirement:	[x] Rule [ ] Other
4. Monitor Information... Manufacturer: TBD Model Number: TBD	Serial Number: TBD
5. Installation Date: After Permit Issuance	6. Performance Specification Test Date: TBD
7. Continuous Monitor Comment: CEMS required by 40 CFR 60.47b (Subpart Db) and proposed for 62-212.400(10) F.A.C (BACT)	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Continuous Monitoring System: Continuous Monitor 3 of 5

1. Parameter Code: EM	2. Pollutant(s): CO
3. CMS Requirement:	[x] Rule [ ] Other
4. Monitor Information... Manufacturer: TBD Model Number: TBD	Serial Number: TBD
5. Installation Date: After Permit Issuance	6. Performance Specification Test Date: TBD
7. Continuous Monitor Comment: CEMS proposed for 62-212.400(10) F.A.C (BACT)	

Continuous Monitoring System: Continuous Monitor 4 of 5

1. Parameter Code: O_2	2. Pollutant(s): N/A
3. CMS Requirement:	[x] Rule [ ] Other
4. Monitor Information... Manufacturer: TBD Model Number: TBD	Serial Number: TBD
5. Installation Date: After Permit Issuance	6. Performance Specification Test Date: TBD
7. Continuous Monitor Comment: CEMS is required by 40 CFR 60.47b and 60.48b (Subpart Db)	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Continuous Monitoring System: Continuous Monitor 5 of 5

1. Parameter Code: VE	2. Pollutant(s): N/A
3. CMS Requirement:	[x] Rule [ ] Other
4. Monitor Information... Manufacturer: TBD Model Number: TBD	Serial Number: TBD
5. Installation Date: After Permit Issuance	6. Performance Specification Test Date: TBD
7. Continuous Monitor Comment: COMS is required by 40 CFR 60.48b (Subpart Db)	

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)
[x] Attached, Document ID: Figure 2-2 [ ] 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: N/A [ ] 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)
[X] Attached, Document ID: Section 5 [ ] 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 ________
[X] 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 ________
[X] 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: ________
[X] To be Submitted, Date (if known): After start-up
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: ________ [X] 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)): [x] Attached, Document ID: Section 5 [ ] Not Applicable
2.	Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): [X] Attached, Document ID: Section 6 [ ] Not Applicable
3.	Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) [ ] Attached, Document ID: Section 4 [X] Not Applicable

Additional Requirements for Title V Air Operation Permit Applications N/A

1.	Identification of Applicable Requirements: [ ] Attached, Document ID: ________
2.	Compliance Assurance Monitoring: [ ] Attached, Document ID: ________ [ ] Not Applicable
3.	Alternative Methods of Operation: [ ] Attached, Document ID: ________ [ ] Not Applicable
4.	Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID: ________ [ ] Not Applicable

Additional Requirements Comment

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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.)

   [X] 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)

   [X] 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: The gas peaking boiler is fired with natural gas and will be used to provide steam to the facility processes during peak demand periods. The boiler is conservatively assumed to operate at full capacity year-round. The unit will utilize best available control technology (BACT) to minimize emissions. Specifically, the boiler will be equipped with either low NOx burners with flue gas reduction or ultra-low NOx burners to control NOx emissions. Good combustion practices will be used to minimize CO and VOC emissions. Natural gas is inherently low in sulfur and produces little PM emissions.

3. Emissions Unit Identification Number: EU010

4. Emissions Unit Status Code: C	5. Commence Construction Date: N/A	6. Initial Startup Date: N/A	7. Emissions Unit Major Group SIC Code: 28

8. Federal Program Applicability: (Check all that apply) N/A

   [ ] Acid Rain Unit

   [ ] CAIR Unit

9. Package Unit:
   Manufacturer: TBD Model Number: TBD

10. Generator Nameplate Rating: N/A MW

11. Emissions Unit Comment: N/A

Emissions Unit Control Equipment/Method: Control 1 of 1

1. Control Equipment/Method Description: Either low NOx burner with flue gas reduction or ultra-low NOx burner	
2. Control Device or Method Code: 205	

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: N/A		
2. Maximum Production Rate: N/A		
3. Maximum Heat Input Rate: 95 MMBtu/hr		
4. Maximum Incineration Rate: N/A pounds/hr N/A tons/day		
5. Requested Maximum Operating Schedule:	24 hours/day 52 weeks/year	7 days/week 8760 hours/year
6. Operating Capacity/Schedule Comment: N/A		

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: Peaking Boiler	2. Emission Point Type Code: 1
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: Stack of boiler	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A	

5. Discharge Type Code: V	6. Stack Height: 32.83 ft	7. Exit Diameter: 4 ft
8. Exit Temperature: 350 °F	9. Actual Volumetric Flow Rate: 29,590 acfm	10. Water Vapor: unknown

11. Maximum Dry Standard Flow Rate: 24,918 dscfm	12. Nonstack Emission Point Height: N/A feet
13. Emission Point UTM Coordinates... Zone: 17 East (km): 493152.15 North (km): 3013457.54	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment:	

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): natural gas peaking boiler (peaking steam demand) Natural Gas <100 MMBtu/hr		
2. Source Classification Code (SCC): 10200602	3. SCC Units: Million Cubic Feet	
4. Maximum Hourly Rate: 0.078	5. Maximum Annual Rate: 687.06	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: N/A	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: 1,020
10. Segment Comment: The peaking boiler will operate only during peak demand periods.		

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	N/A	N/A	NS
PM_{10}	N/A	N/A	NS
$PM_{2.5}$	N/A	N/A	NS
SO_2	N/A	N/A	NS
NO_X	205	N/A	NS
CO	N/A	N/A	NS
HAPs	N/A	N/A	NS

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: N/A
3. Potential Emissions: 0.133 lb/hour 0.583 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.0014 lbs/MMBtu Reference: EPA AP-42, Section 1.4, Natural Gas Combustion, July 1998.	7. Emissions Method Code: 3
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment:	

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_{10}	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 0.380 lb/hour 1.664 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.0022 lb PM per MMBtu Reference: EPA AP-42, Section 1.4, Natural Gas Combustion, July 1998.	7. Emissions Method Code: 3
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment:	

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: $PM_{2.5}$	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 0.380 lb/hour 1.664 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.0022lb PM per MMBtu Reference: EPA AP-42, Section 1.4, Natural Gas Combustion, July 1998.	7. Emissions Method Code: 3
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment:	

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: SO_2	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 0.532 lb/hour 2.33 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.0055964 lb SO_2 per MMBtu Reference: EPA AP-42, Section 1.4, Natural Gas Combustion, July 1998.	7. Emissions Method Code: 3
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment:	

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: NO_X	2. Total Percent Efficiency of Control: Not quantifiable
3. Potential Emissions: 3.33 lb/hour 14.6 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.035 lb NO_X per MMBtu Reference: EPA AP-42, Section 1.4, Natural Gas Combustion, July 1998.	7. Emissions Method Code: 3
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment:	

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: N/A
3. Potential Emissions: 3.52 lb/hour 15.4 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.037 lb CO per MMBtu Reference: EPA AP-42, Section 1.4, Natural Gas Combustion, July 1998.	7. Emissions Method Code: 3
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment:	

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: N/A
3. Potential Emissions: 0.176 lb/hour 0.770 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: See emissions inventory calculations in Appendix B for pollutant-specific emission factors. Reference: Emission factors based on EPA AP-42, Section 14 "Natural Gas Combustion", July 1998.	7. Emissions Method Code: 3
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment: HAP emissions based on natural gas combustion.	

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 6

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: Upon Permit Issuance
3. Allowable Emissions and Units: 0.0022 lb/MMBtu (filterable)	4. Equivalent Allowable Emissions: 0.38 lb/hour 1.664 tons/year
5. Method of Compliance: EPA Method 5 compliance test	
6. Allowable Emissions Comment (Description of Operating Method): Proposed PM_{10} BACT Emission Limit per 62-212.400(10) F.A.C.	

Allowable Emissions Allowable Emissions 2 of 6

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: Upon Permit Issuance
3. Allowable Emissions and Units: 0.0022 lb/MMBtu	4. Equivalent Allowable Emissions: 0.38 lb/hour 1.664 tons/year
5. Method of Compliance: EPA Method 5 compliance test (PM_{10} is a surrogate for $PM_{2.5}$)	
6. Allowable Emissions Comment (Description of Operating Method): Proposed $PM_{2.5}$ BACT Emission Limit per 62-212.400(10) F.A.C.	

Allowable Emissions Allowable Emissions 3 of 6

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: Upon Permit Issuance
3. Allowable Emissions and Units: 0.0056 lb/MMBtu	4. Equivalent Allowable Emissions: 0.532 lb/hour 2.33 tons/year
5. Method of Compliance: EPA Method 6C compliance test	
6. Allowable Emissions Comment (Description of Operating Method): Proposed SO_2 BACT Emission Limit per 62-212.400(10) F.A.C.	

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 4 of 6

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: Upon Permit Issuance
3. Allowable Emissions and Units: 0.035 lb/MMBtu	4. Equivalent Allowable Emissions: 3.33 lb/hour 14.6 tons/year
5. Method of Compliance: EPA Method 7E compliance test	
6. Allowable Emissions Comment (Description of Operating Method): Proposed NO_X BACT Emission Limit per 62-212.400(10) F.A.C.	

Allowable Emissions Allowable Emissions 5 of 6

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: Upon Permit Issuance
3. Allowable Emissions and Units: 0.037 lb/MMBtu	4. Equivalent Allowable Emissions: 3.52 lb/hour 15.4 tons/year
5. Method of Compliance: EPA Method 10B compliance test	
6. Allowable Emissions Comment (Description of Operating Method): Proposed CO BACT Emission Limit per 62-212.400(10) F.A.C.	

Allowable Emissions Allowable Emissions 6 of 6

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: Upon Permit Issuance
3. Allowable Emissions and Units: 0.0014 lb/MMBtu	4. Equivalent Allowable Emissions: 0.133 lb/hour 0.583 tons/year
5. Method of Compliance: EPA Method 25 or 25A compliance test	
6. Allowable Emissions Comment (Description of Operating Method): Proposed VOC BACT Emission Limit per 62-212.400(10) F.A.C.	

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: [x] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: 20 % Exceptional Conditions: 27 % Maximum Period of Excess Opacity Allowed: 6 min/hour OR Normal Conditions: 20 % Exceptional Conditions: 40 % Maximum Period of Excess Opacity Allowed: 2 min/hour	
4. Method of Compliance: EPA Method 9	
5. Visible Emissions Comment: VE limitation required by 62-296.406 F.A.C. (Fossil Fuel Steam Generators with less than 250 MMBtu/hr Heat Input, New and Existing Emission Units).	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: VE20	2. Basis for Allowable Opacity: [x] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: 20 % Exceptional Conditions: N/A % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: EPA Method 9	
5. Visible Emissions Comment: VE limitation required by 62-296.320(4)(b) F.A.C. (General Visible Emission Standard)	

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring. N/A

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) [x] Attached, Document ID: Figure 2-2 [ ] 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: N/A [ ] 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) [X] Attached, Document ID: Section 5 [ ] 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 ______ [X] 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 ______ [X] 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: ______ [X] To be Submitted, Date (if known): After start-up 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: ______ [X] 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)): ☒ Attached, Document ID: Section 5 ☐ Not Applicable
2.	Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): ☒ Attached, Document ID: Section 6 ☐ Not Applicable
3.	Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: ____ ☒ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications N/A

1.	Identification of Applicable Requirements: ☐ Attached, Document ID: ____
2.	Compliance Assurance Monitoring: ☐ Attached, Document ID: ____ ☐ Not Applicable
3.	Alternative Methods of Operation: ☐ Attached, Document ID: ____ ☐ Not Applicable
4.	Alternative Modes of Operation (Emissions Trading): ☐ 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.)

   [X] 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)

   [X] 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: Cooling Tower. Process cooling will be provided by an induced draft cooling tower with 4 cells.

3. Emissions Unit Identification Number: EU011

4. Emissions Unit Status Code: C	5. Commence Construction Date: N/A	6. Initial Startup Date: N/A	7. Emissions Unit Major Group SIC Code: 28

8. Federal Program Applicability: (Check all that apply) N/A

   [ ] Acid Rain Unit

   [ ] CAIR Unit

9. Package Unit: N/A
   Manufacturer: Model Number:

10. Generator Nameplate Rating: N/A MW

11. Emissions Unit Comment: N/A

Emissions Unit Control Equipment/Method: Control 1 of 2

1. Control Equipment/Method Description: Mist Eliminator - High Velocity	
2. Control Device or Method Code: 014	

Emissions Unit Control Equipment/Method: Control 2 of 2

1. Control Equipment/Method Description: Cooling Water Leak Monitoring and Repair	
2. Control Device or Method Code: 099	

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: 50,000 gal/min of water		
2. Maximum Production Rate: N/A		
3. Maximum Heat Input Rate: N/A		
4. Maximum Incineration Rate: N/A pounds/hr N/A tons/day		
5. Requested Maximum Operating Schedule:	24 hours/day 52 weeks/year	7 days/week 8760 hours/year
6. Operating Capacity/Schedule Comment: N/A		

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: N/A	2. Emission Point Type Code: 3
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: N/A	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A	

5. Discharge Type Code: P	6. Stack Height: 54.10 ft	7. Exit Diameter: 32.8 ft
8. Exit Temperature: 94 °F	9. Actual Volumetric Flow Rate: 5,881,420 acfm	10. Water Vapor: unknown

11. Maximum Dry Standard Flow Rate: N/A dscfm	12. Nonstack Emission Point Height: N/A feet
13. Emission Point UTM Coordinates... Zone: 17 East (km): 493,263.58 North (km): 3,013,427.3	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: UTM coordinates provided for cooling tower cell No. 4, which is representative. Stack parameters (height and diameter) shown are for each single cooling tower cell. Volumetric flow shown is for the entire cooling tower.	

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): Process Cooling Mechanical Draft		
2. Source Classification Code (SCC): 38500101	3. SCC Units: Million Gallons	
4. Maximum Hourly Rate: 3.0	5. Maximum Annual Rate: 26,280	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: N/A	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: N/A
10. Segment Comment: Flow rate of 50,000 gallons/minute (GPM) cooling water		

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_{10}	014	N/A	EL
$PM_{2.5}$	014	N/A	EL
VOC	099	N/A	EL
HAPs	099	N/A	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_{10}	2. Total Percent Efficiency of Control: Control to 0.0005% drift loss
3. Potential Emissions: 0.3 lb/hour 1.5 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: Assume a TDS of 2,750 mg/L and drift loss of 0.0005% Reference:	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment:	

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: $PM_{2.5}$	2. Total Percent Efficiency of Control: Control to 0.0005% drift loss
3. Potential Emissions: 0.3 lb/hour 1.5 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: Assume a TDS of 2,750 mg/L and drift loss of 0.0005% Reference:	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment:	

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: N/A
3. Potential Emissions: 2.1 lb/hour 9.2 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.7 lb VOC / MGD Reference: SCAQMD, 2006. "Guidelines for Calculating Emissions from Cooling Towers." June 2006.	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment:	

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: N/A
3. Potential Emissions: 0.11 lb/hour 0.5 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 5% of VOC Reference: Assumed	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
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 4

1. Basis for Allowable Emissions Code: Rule	2. Future Effective Date of Allowable Emissions: Upon permit revision
3. Allowable Emissions and Units: 0.0005% Drift	4. Equivalent Allowable Emissions: 0.3 lb/hour 1.5 tons/year
5. Method of Compliance: Equipment design	
6. Allowable Emissions Comment (Description of Operating Method): Proposed PM_{10} BACT Emission Limit per 62-212.400(10) F.A.C.	

Allowable Emissions Allowable Emissions 2 of 4

1. Basis for Allowable Emissions Code: Rule	2. Future Effective Date of Allowable Emissions: Upon permit revision
3. Allowable Emissions and Units: 0.0005% Drift	4. Equivalent Allowable Emissions: 0.3 lb/hour 1.5 tons/year
5. Method of Compliance: Equipment design	
6. Allowable Emissions Comment (Description of Operating Method): Proposed $PM_{2.5}$ BACT Emission Limit per 62-212.400(10) F.A.C.	

Allowable Emissions Allowable Emissions 3 of 4

1. Basis for Allowable Emissions Code: Rule	2. Future Effective Date of Allowable Emissions: Upon permit revision
3. Allowable Emissions and Units: Leak Detection	4. Equivalent Allowable Emissions: 2.1 lb/hour 9.2 tons/year
5. Method of Compliance: Leak Detection and Repair	
6. Allowable Emissions Comment (Description of Operating Method): VOCs	

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 4 of 4

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: Upon Permit Issuance
3. Allowable Emissions and Units: Leak Detection	4. Equivalent Allowable Emissions: 0.11 lb/hour 0.5 tons/year
5. Method of Compliance: Leak Detection and Repair	
6. Allowable Emissions Comment (Description of Operating Method): HAPs	

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: [X] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: 20 % Exceptional Conditions: N/A % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: EPA Method 9	
5. Visible Emissions Comment: VE limitation required by 62-296.320(4)(b) F.A.C. (General Visible Emission Standard)	

Visible Emissions Limitation: Visible Emissions Limitation __ of ____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % 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. N/A

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)
   [x] Attached, Document ID: Figure 2-2 [ ] 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: N/A [ ] 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)
   [x] Attached, Document ID: Section 5 [ ] 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 ______
   [x] 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 ______
   [x] 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: ______
   [x] To be Submitted, Date (if known): After start-up
   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: ______ [x] 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)): [x] Attached, Document ID: Section 5 [ ] Not Applicable
2.	Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): [X] Attached, Document ID: Section 6 [ ] Not Applicable
3.	Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) [ ] Attached, Document ID:________ [X] Not Applicable

Additional Requirements for Title V Air Operation Permit Applications N/A

1.	Identification of Applicable Requirements: [ ] Attached, Document ID: ________
2.	Compliance Assurance Monitoring: [ ] Attached, Document ID: ________ [ ] Not Applicable
3.	Alternative Methods of Operation: [ ] Attached, Document ID: ________ [ ] Not Applicable
4.	Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID: ________ [ ] Not Applicable

Additional Requirements Comment

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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.)

   [X] 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)

   [X] 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 storage silos: powdered cellulose, wheat bran, ammonium sulfate, potassium phosphate, urea, hydrated lime, ash, sand, and limestone).

3. Emissions Unit Identification Number: EU012

4. Emissions Unit Status Code: C	5. Commence Construction Date: N/A	6. Initial Startup Date: N/A	7. Emissions Unit Major Group SIC Code: 28

8. Federal Program Applicability: (Check all that apply) N/A

   [ ] Acid Rain Unit

   [ ] CAIR Unit

9. Package Unit:
   Manufacturer: Various   Model Number: Various

10. Generator Nameplate Rating: N/A MW

11. Emissions Unit Comment: N/A

Emissions Unit Control Equipment/Method: Control 1 of 1

1. Control Equipment/Method Description: Low Temperature Fabric Filter (Baghouse)
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: Varies, See Appendix B.		
2. Maximum Production Rate: Varies, See Appendix B.		
3. Maximum Heat Input Rate: N/A		
4. Maximum Incineration Rate: N/A pounds/hr N/A tons/day		
5. Requested Maximum Operating Schedule:	24 hours/day 52 weeks/year	7 days/week 8760 hours/year
6. Operating Capacity/Schedule Comment: N/A		

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: Nutrients	2. Emission Point Type Code: 3
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: Fabric bin vent filter exhaust on each silo.	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A	

5. Discharge Type Code: V	6. Stack Height: 48 ft	7. Exit Diameter: 1 ft
8. Exit Temperature: 80 °F	9. Actual Volumetric Flow Rate: 2,500 acfm	10. Water Vapor: unknown

11. Maximum Dry Standard Flow Rate: 2,458 dscfm	12. Nonstack Emission Point Height: N/A feet
13. Emission Point UTM Coordinates... Zone: 17 East (km): 493235.76 North (km): 3013263.24	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: Stack parameters correspond to the wheat bran storage silo, which is representative.	

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): Storage of materials associated with chemical manufacturing		
2. Source Classification Code (SCC): 30183001	3. SCC Units: Tons	
4. Maximum Hourly Rate: N/A	5. Maximum Annual Rate: Varies	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: N/A	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: N/A
10. Segment Comment: N/A		

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_{10}	018	N/A	EL
$PM_{2.5}$	018	N/A	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.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: PM_{10}	2. Total Percent Efficiency of Control: 99%
3. Potential Emissions: 1.0 lb/hour 4.5 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.005 gr/dscf Reference: Emission factor is equal to proposed BACT emission limit.	7. Emissions Method Code: 0
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment:	

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: $PM_{2.5}$	2. Total Percent Efficiency of Control: 99%
3. Potential Emissions: 1.0 lb/hour 4.5 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.005 gr/dscf Reference: Emission factor is equal to proposed BACT emission limit.	7. Emissions Method Code: 0
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
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 2

1. Basis for Allowable Emissions Code: Rule	2. Future Effective Date of Allowable Emissions: Upon permit revision
3. Allowable Emissions and Units: 0.005 gr/dscf	4. Equivalent Allowable Emissions: 1.0 lb/hour 4.5 tons/year
5. Method of Compliance: Equipment design	
6. Allowable Emissions Comment (Description of Operating Method): Proposed PM_{10} BACT Emission Limit per 62-212.400(10) F.A.C.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: Rule	2. Future Effective Date of Allowable Emissions: Upon permit revision
3. Allowable Emissions and Units: 0.005 gr/dscf	4. Equivalent Allowable Emissions: 1.0 lb/hour 4.5 tons/year
5. Method of Compliance: Equipment design	
6. Allowable Emissions Comment (Description of Operating Method): Proposed $PM_{2.5}$ BACT Emission Limit per 62-212.400(10) F.A.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):	

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: N/A % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: EPA Method 9	
5. Visible Emissions Comment: VE limitation required by 62-296.320(4)(b) F.A.C. (General Visible Emission Standard)	

Visible Emissions Limitation: Visible Emissions Limitation __ of ____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % 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. N/A

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)
[x] Attached, Document ID: Figure 2-2 [ ] 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: N/A [ ] 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)
[X] Attached, Document ID: Section 5 [ ] 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 ______
[X] 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 ______
[X] 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: ______
[X] To be Submitted, Date (if known): After start-up
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: ______ [X] 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)): [x] Attached, Document ID: Section 5 [ ] Not Applicable
2.	Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): [X] Attached, Document ID: Section 6 [ ] Not Applicable
3.	Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) [ ] Attached, Document ID:__________ [X] Not Applicable

Additional Requirements for Title V Air Operation Permit Applications N/A

1.	Identification of Applicable Requirements: [ ] Attached, Document ID: __________
2.	Compliance Assurance Monitoring: [ ] Attached, Document ID: __________ [ ] Not Applicable
3.	Alternative Methods of Operation: [ ] Attached, Document ID: __________ [ ] Not Applicable
4.	Alternative Modes of Operation (Emissions Trading): [ ] 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.)

   [X] 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)

   [X] 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: Five emergency generators will be used in the event of power supply disruptions. The engines will be tested weekly for approximately 1 hour or less, and will be limited to less than 100 non-emergency hours per year. Emissions listed here are per each engine.

3. Emissions Unit Identification Number: EU014

4. Emissions Unit Status Code: C	5. Commence Construction Date: N/A	6. Initial Startup Date: N/A	7. Emissions Unit Major Group SIC Code: 28

8. Federal Program Applicability: (Check all that apply) N/A

   [ ] Acid Rain Unit

   [ ] CAIR Unit

9. Package Unit:
   Manufacturer: TBD Model Number: TBD

10. Generator Nameplate Rating: 1.5 MW each (total of five units)

11. Emissions Unit Comment: Emergency Generators will be tested weekly for approximately 1 hour or less, and will be limited to less than 100 hours each per year for testing and maintenance per 40 CFR 60, Subpart IIII. Emissions assume maximum operations of 500 hours per year.

Emissions Unit Control Equipment/Method: Control __ of __

1. Control Equipment/Method Description: None	
2. Control Device or Method Code: N/A	

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: N/A		
2. Maximum Production Rate: N/A		
3. Maximum Heat Input Rate: 14.59 MMBtu/hr		
4. Maximum Incineration Rate:	N/A pounds/hr N/A tons/day	
5. Requested Maximum Operating Schedule:	24 hours/day 52 weeks/year	7 days/week up to 500 hours/year
6. Operating Capacity/Schedule Comment: The emergency generators will be tested weekly for approximately 1 hour or less, and will be limited to less than 100 hours per year for testing and maintenance per 40 CFR 60, Subpart IIII. Emissions are based on an assumed maximum operating time of 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: N/A		2. Emission Point Type Code: 1
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: N/A		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A		
5. Discharge Type Code: V	6. Stack Height: TBD feet	7. Exit Diameter: TBD feet
8. Exit Temperature: TBD °F	9. Actual Volumetric Flow Rate: TBD acfm	10. Water Vapor: TBD %
11. Maximum Dry Standard Flow Rate: TBD dscfm		12. Nonstack Emission Point Height: N/A feet
13. Emission Point UTM Coordinates. Zone: 17 East (km): TBD North (km): TBD		14. Emission Point Latitude/Longitude… Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: N/A		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): Distillate (Diesel Oil) Reciprocating Internal Combustion Engine		
2. Source Classification Code (SCC): 20200102	3. SCC Units: 1000 Gallons	
4. Maximum Hourly Rate: 0.104 each	5. Maximum Annual Rate: 52.09 each	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: 0.0015	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: 140
10. Segment Comment: The emergency generators will be tested weekly for approximately 1 hour or less, and will be limited to less than 100 hours per year for testing and maintenance per 40 CFR 60, Subpart IIII. The maximum annual rate is based on an assumed maximum operating time of 500 hr/yr.		

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_{10}	N/A	N/A	EL
$PM_{2.5}$	N/A	N/A	EL
SO_2	N/A	N/A	EL
NO_X	N/A	N/A	EL
CO	N/A	N/A	EL
VOC	N/A	N/A	EL
HAPS*	N/A	N/A	NS
H001	N/A	N/A	NS
H006	N/A	N/A	NS
H017	N/A	N/A	NS
H095	N/A	N/A	NS
H169	N/A	N/A	NS
H186	N/A	N/A	NS

*** Although the facility is not major for HAPs, the HAPs emitted are provided in Section E and emissions of total HAPs are provided in Section F1 for informational purposes.**

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_{10}	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 0.661 lb/hour 0.165 tons/year	4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.2 g/hp-hr Reference: 40 CFR 60, Subpart IIII	7. Emissions Method Code: 0
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A [ ] 5 years [ ] 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment: The emergency generators will be tested weekly for approximately 1 hour or less, and will be limited to less than 100 hours per year for testing and maintenance per 40 CFR 60, Subpart IIII. Emissions are based on an assumed maximum operating time of 500 hr/yr.	

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: $PM_{2.5}$	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 0.661 lb/hour 0.165 tons/year	4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.2 g/hp-hr Reference: 40 CFR 60, Subpart IIII	7. Emissions Method Code: 0
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A [ ] 5 years [ ] 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment: PM_{10} is a surrogate for $PM_{2.5}$. The emergency generators will be tested weekly for approximately 1 hour or less, and will be limited to less than 100 hours per year for testing and maintenance per 40 CFR 60, Subpart IIII. Emissions are based on an assumed maximum operating time of 500 hr/yr.	

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: SO_2	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 0.024 lb/hour 0.006 tons/year	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.0074 g/hp-hr Reference: 40 CFR 60, Subpart IIII	7. Emissions Method Code: 0
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A [ ] 5 years [ ] 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment: The emergency generators will be tested weekly for approximately 1 hour or less, and will be limited to less than 100 hours per year for testing and maintenance per 40 CFR 60, Subpart IIII. Emissions are based on an assumed maximum operating time of 500 hr/yr.	

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: NO_X	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 19.0 lb/hour 4.76 tons/year	4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 5.76 g/hp-hr Reference: 40 CFR 60, Subpart IIII	7. Emissions Method Code: 0
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A [ ] 5 years [ ] 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment: The emergency generators will be tested weekly for approximately 1 hour or less, and will be limited to less than 100 hours per year for testing and maintenance per 40 CFR 60, Subpart IIII. Emissions are based on an assumed maximum operating time of 500 hr/yr.	

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: N/A
3. Potential Emissions: 11.57 lb/hour 2.89 tons/year	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 3.5 g/hp-hr Reference: 40 CFR 60, Subpart IIII	7. Emissions Method Code: 0
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A [ ] 5 years [ ] 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment: The emergency generators will be tested weekly for approximately 1 hour or less, and will be limited to less than 100 hours per year for testing and maintenance per 40 CFR 60, Subpart IIII. Emissions are based on an assumed maximum operating time of 500 hr/yr.	

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: N/A
3. Potential Emissions: 2.12 lb/hour 0.529 tons/year	4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.64 g/hp-hr Reference: 40 CFR 60, Subpart IIII	7. Emissions Method Code: 0
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A [ ] 5 years [ ] 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment: The emergency generators will be tested weekly for approximately 1 hour or less, and will be limited to less than 100 hours per year for testing and maintenance per 40 CFR 60, Subpart IIII. Emissions are based on an assumed maximum operating time of 500 hr/yr.	

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: N/A
3. Potential Emissions: 0.0577 lb/hour 0.0144 tons/year	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: See emissions inventory calculations in Appendix B for pollutant-specific emission factors. Reference: EPA AP-42, Table 3.4-3: Speciated Organic Compound Emission Factors for Large Uncontrolled Stationary Diesel Engines, October 1996.	7. Emissions Method Code: 3
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A [ ] 5 years [ ] 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment: The emergency generators will be tested weekly for approximately 1 hour or less, and will be limited to less than 100 hours per year for testing and maintenance per 40 CFR 60, Subpart IIII. Emissions are based on an assumed maximum operating time of 500 hr/yr.	

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 6

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: Upon Permit Issuance
3. Allowable Emissions and Units: 0.2 g/kW-hr	4. Equivalent Allowable Emissions: 0.661 lb/hour 0.165 tons/year
5. Method of Compliance: as specified in 40 CFR 60, Subpart IIII	
6. Allowable Emissions Comment (Description of Operating Method): 40 CFR 60, Subpart IIII and Proposed PM_{10} BACT Emission Limit per 62-212.400(10) F.A.C.	

Allowable Emissions Allowable Emissions 2 of 6

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: Upon Permit Issuance
3. Allowable Emissions and Units: 0.2 g/kW-hr	4. Equivalent Allowable Emissions: 0.661 lb/hour 0.165 tons/year
5. Method of Compliance: as specified in 40 CFR 60, Subpart IIII	
6. Allowable Emissions Comment (Description of Operating Method): 40 CFR 60, Subpart IIII and Proposed $PM_{2.5}$ BACT Emission Limit per 62-212.400(10) F.A.C.	

Allowable Emissions Allowable Emissions 3 of 6

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: Upon Permit Issuance
3. Allowable Emissions and Units: 0.0015% sulfur content	4. Equivalent Allowable Emissions: 0.0244 lb/hour 0.0061 tons/year
5. Method of Compliance: as specified in 40 CFR 60, Subpart IIII	
6. Allowable Emissions Comment (Description of Operating Method): 40 CFR 60, Subpart IIII and Proposed SO_2 BACT Emission Limit per 62-212.400(10) F.A.C.	

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 4 of 6

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: Upon Permit Issuance
3. Allowable Emissions and Units: 5.76 g/kW-hr	4. Equivalent Allowable Emissions: 19.0 lb/hour 4.76 tons/year
5. Method of Compliance: as specified in 40 CFR 60, Subpart IIII	
6. Allowable Emissions Comment (Description of Operating Method): 40 CFR 60, Subpart IIII and Proposed NO_X BACT Emission Limit per 62-212.400(10) F.A.C.	

Allowable Emissions Allowable Emissions 5 of 6

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: Upon Permit Issuance
3. Allowable Emissions and Units: 3.5 g/kW-hr	4. Equivalent Allowable Emissions: 11.57 lb/hour 2.89 tons/year
5. Method of Compliance: as specified in 40 CFR 60, Subpart IIII	
6. Allowable Emissions Comment (Description of Operating Method): 40 CFR 60, Subpart IIII and Proposed CO BACT Emission Limit per 62-212.400(10) F.A.C.	

Allowable Emissions Allowable Emissions 6 of 6

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: Upon Permit Issuance
3. Allowable Emissions and Units: 0.64 g/kW-hr	4. Equivalent Allowable Emissions: 11.3 lb/hour 2.8 tons/year
5. Method of Compliance: as specified in 40 CFR 60, Subpart IIII	
6. Allowable Emissions Comment (Description of Operating Method): 40 CFR 60, Subpart IIII and Proposed VOC BACT Emission Limit per 62-212.400(10) F.A.C.	

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: [x] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: 20 % Exceptional Conditions: N/A % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: EPA Method 9	
5. Visible Emissions Comment: VE limitation required by 62-296.320(4)(b) F.A.C. (General Visible Emission Standard)	

Visible Emissions Limitation: Visible Emissions Limitation __ of ___

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % 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. N/A

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)
   [X] Attached, Document ID: Figure 2-2 [ ] 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: NA [ ] 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)
   [X] Attached, Document ID: Section 5 [ ] 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 ____
   [X] 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 ____
   [X] 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: ____
   [X] To be Submitted, Date (if known): : ____
   Test Date(s)/Pollutant(s) Tested: After Start-Up
   [ ] 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: ____ [X] 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)): ☒ Attached, Document ID: Section 5 ☐ Not Applicable
2.	Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): ☒ Attached, Document ID: Section 6 ☐ Not Applicable
3.	Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID:__________ ☒ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications (N/A)

1.	Identification of Applicable Requirements: ☐ Attached, Document ID: __________
2.	Compliance Assurance Monitoring: ☐ Attached, Document ID: __________ ☐ Not Applicable
3.	Alternative Methods of Operation: ☐ Attached, Document ID: __________ ☐ Not Applicable
4.	Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: __________ ☐ Not Applicable

Additional Requirements Comment

N/A

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.)

   [X] 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)

   [X] 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:
The diesel pump will be used in the event of a fire. The pump will be tested weekly for approximately 1 hour or less, and will be operationally limited to 100 non-emergency hours per year.

3. Emissions Unit Identification Number: EU015

4. Emissions Unit Status Code: C	5. Commence Construction Date: N/A	6. Initial Startup Date: N/A	7. Emissions Unit Major Group SIC Code: 28

8. Federal Program Applicability: (Check all that apply) N/A

   [ ] Acid Rain Unit

   [ ] CAIR Unit

9. Package Unit:
Manufacturer: TBD Model Number: TBD

10. Generator Nameplate Rating: N/A MW

11. Emissions Unit Comment: The pump will be tested weekly for approximately 1 hour or less, and will be limited to less than 100 hours per year for testing and maintenance per 40 CFR 60, Subpart IIII. Emissions are based on an assumed maximum operating time of 500 hr/yr.

Emissions Unit Control Equipment/Method: Control 1 of 1

1. Control Equipment/Method Description: None
2. Control Device or Method Code: N/A

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: N/A
2. Maximum Production Rate: N/A
3. Maximum Heat Input Rate: 6.16 million Btu/hr
4. Maximum Incineration Rate: N/A pounds/hr N/A tons/day
5. Requested Maximum Operating Schedule: 24 hours/day 7 days/week 52 weeks/year up to 500 hours/year
6. Operating Capacity/Schedule Comment: The fire pump will be tested weekly for approximately 1 hour or less, and will be limited to less than 100 hours per year for testing and maintenance per 40 CFR 60, Subpart IIII. Emissions are based on an assumed maximum operating time of 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: N/A		2. Emission Point Type Code: 1
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: N/A		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A		
5. Discharge Type Code: V	6. Stack Height: TBD feet	7. Exit Diameter: TBD feet
8. Exit Temperature: TBD °F	9. Actual Volumetric Flow Rate: TBD acfm	10. Water Vapor: TBD %
11. Maximum Dry Standard Flow Rate: TBD dscfm		12. Nonstack Emission Point Height: N/A feet
13. Emission Point UTM Coordinates. Zone: 17 East (km): TBD North (km): TBD		14. Emission Point Latitude/Longitude… Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: N/A		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): Distillate (Diesel Oil) Reciprocating Internal Combustion Engine		
2. Source Classification Code (SCC): 20200102	3. SCC Units: 1000 Gallons	
4. Maximum Hourly Rate: 0.0425	5. Maximum Annual Rate: 21.25	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: 0.0015	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: 140
10. Segment Comment: The fire pump will be tested weekly for approximately 1 hour or less, and will be limited to less than 100 hours per year for testing and maintenance per 40 CFR 60, Subpart IIII. The maximum annual rate is based on an assumed maximum operating time of 500 hr/yr.		

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_{10}	N/A	N/A	EL
$PM_{2.5}$	N/A	N/A	EL
SO_2	N/A	N/A	EL
NO_X	N/A	N/A	EL
CO	N/A	N/A	EL
VOC	N/A	N/A	EL
HAPS*	N/A	N/A	NS
H001	N/A	N/A	NS
H006	N/A	N/A	NS
H017	N/A	N/A	NS
H095	N/A	N/A	NS
H169	N/A	N/A	NS
H186	N/A	N/A	NS
H132	N/A	N/A	NS
H151	N/A	N/A	NS

*** Although the facility is not major for HAPs, the HAPs emitted are provided in Section E and emissions of total HAPs are provided in Section F1 for informational purposes.**

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_{10}	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 0.279 lb/hour 0.070 tons/year	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.15 g/hp-hr Reference: 40 CFR 60, Subpart IIII	7. Emissions Method Code: 0
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A [ ] 5 years [ ] 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment: The fire pump will be tested weekly for approximately 1 hour or less, and will be limited to less than 100 hours per year for testing and maintenance per 40 CFR 60, Subpart IIII. Emissions are based on an assumed maximum operating time of 500 hr/yr.	

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: $PM_{2.5}$	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 0.279 lb/hour 0.070 tons/year	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.15 g/hp-hr Reference: 40 CFR 60, Subpart IIII	7. Emissions Method Code: 0
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A [ ] 5 years [ ] 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment: PM10 is a surrogate for PM2.5. The fire pump will be tested weekly for approximately 1 hour or less, and will be limited to less than 100 hours per year for testing and maintenance per 40 CFR 60, Subpart IIII. Emissions are based on an assumed maximum operating time of 500 hr/yr.	

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: SO_2	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 0.01 lb/hour 0.00258 tons/year	4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.0055 g/hp-hr Reference: 40 CFR 60, Subpart IIII	7. Emissions Method Code: 0
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A [ ] 5 years [ ] 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment: The fire pump will be tested weekly for approximately 1 hour or less, and will be limited to less than 100 hours per year for testing and maintenance per 40 CFR 60, Subpart IIII. Emissions are based on an assumed maximum operating time of 500 hr/yr.	

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: NO_X	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 8.0 lb/hour 2.01 tons/year	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 5.76 g/kW-hr Reference: 40 CFR 60, Subpart IIII	7. Emissions Method Code: 0
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A [ ] 5 years [ ] 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment: The fire pump will be tested weekly for approximately 1 hour or less, and will be limited to less than 100 hours per year for testing and maintenance per 40 CFR 60, Subpart IIII. Emissions are based on an assumed maximum operating time of 500 hr/yr.	

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: N/A
3. Potential Emissions: 4.89 lb/hour 1.22 tons/year	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 3.5 g/kW-hr Reference: 40 CFR 60, Subpart IIII	7. Emissions Method Code: 0
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A [ ] 5 years [ ] 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment: The fire pump will be tested weekly for approximately 1 hour or less, and will be limited to less than 100 hours per year for testing and maintenance per 40 CFR 60, Subpart IIII. Emissions are based on an assumed maximum operating time of 500 hr/yr.	

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: N/A
3. Potential Emissions: 0.89 lb/hour 0.224 tons/year	4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: 0.64 g/kW-hr Reference: 40 CFR 60, Subpart IIII	7. Emissions Method Code: 0
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A [ ] 5 years [ ] 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment: The fire pump will be tested weekly for approximately 1 hour or less, and will be limited to less than 100 hours per year for testing and maintenance per 40 CFR 60, Subpart IIII. Emissions are based on an assumed maximum operating time of 500 hr/yr.	

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: N/A
3. Potential Emissions: 0.0244 lb/hour 0.0061 tons/year	4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year	
6. Emission Factor: See emissions inventory calculations in Appendix B for pollutant-specific emission factors. Reference: EPA AP-42, Table 3.4-3: Speciated Organic Compound Emission Factors for Large Uncontrolled Stationary Diesel Engines, October 1996.	7. Emissions Method Code: 3
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A [ ] 5 years [ ] 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment: The fire pump will be tested weekly for approximately 1 hour or less, and will be limited to less than 100 hours per year for testing and maintenance per 40 CFR 60, Subpart IIII. Emissions are based on an assumed maximum operating time of 500 hr/yr.	

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 6

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: Upon Permit Issuance
3. Allowable Emissions and Units: 0.15 g/hp-hr (filterable)	4. Equivalent Allowable Emissions: 0.279 lb/hour 0.070 tons/year
5. Method of Compliance: as specified in 40 CFR 60, Subpart IIII	
6. Allowable Emissions Comment (Description of Operating Method): 40 CFR 60, Subpart IIII and Proposed PM_{10} BACT Emission Limit per 62-212.400(10) F.A.C.	

Allowable Emissions Allowable Emissions 2 of 6

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: Upon Permit Issuance
3. Allowable Emissions and Units: 0.15 g/hp-hr	4. Equivalent Allowable Emissions: 0.279 lb/hour 0.070 tons/year
5. Method of Compliance: as specified in 40 CFR 60, Subpart IIII	
6. Allowable Emissions Comment (Description of Operating Method): 40 CFR 60, Subpart IIII and Proposed $PM_{2.5}$ BACT Emission Limit per 62-212.400(10) F.A.C.	

Allowable Emissions Allowable Emissions 3 of 6

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: Upon Permit Issuance
3. Allowable Emissions and Units: 0.0015% sulfur content 0.0055 g/hp-hr	4. Equivalent Allowable Emissions: 0.0103 lb/hour 0.00258 tons/year
5. Method of Compliance: as specified in 40 CFR 60, Subpart IIII	
6. Allowable Emissions Comment (Description of Operating Method): 40 CFR 60, Subpart IIII and Proposed SO_2 BACT Emission Limit per 62-212.400(10) F.A.C.	

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 4 of 6

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: Upon Permit Issuance
3. Allowable Emissions and Units: 2.7 g/hp-hr	4. Equivalent Allowable Emissions: 8.0 lb/hour 2.01 tons/year
5. Method of Compliance: as specified in 40 CFR 60, Subpart IIII	
6. Allowable Emissions Comment (Description of Operating Method): 40 CFR 60, Subpart IIII and Proposed NO_X BACT Emission Limit per 62-212.400(10) F.A.C.	

Allowable Emissions Allowable Emissions 5 of 6

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: Upon Permit Issuance
3. Allowable Emissions and Units: 2.6 g/hp-hr	4. Equivalent Allowable Emissions: 4.89 lb/hour 1.22 tons/year
5. Method of Compliance: as specified in 40 CFR 60, Subpart IIII	
6. Allowable Emissions Comment (Description of Operating Method): 40 CFR 60, Subpart IIII and Proposed CO BACT Emission Limit per 62-212.400(10) F.A.C.	

Allowable Emissions Allowable Emissions 6 of 6

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: Upon Permit Issuance
3. Allowable Emissions and Units: 0.3 g/hp-hr	4. Equivalent Allowable Emissions: 0.89 lb/hour 0.224 tons/year
5. Method of Compliance: as specified in 40 CFR 60, Subpart IIII	
6. Allowable Emissions Comment (Description of Operating Method): 40 CFR 60, Subpart IIII and Proposed VOC BACT Emission Limit per 62-212.400(10) F.A.C.	

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: [x] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: 20 % Exceptional Conditions: N/A % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: EPA Method 9	
5. Visible Emissions Comment: VE limitation required by 62-296.320(4)(b) F.A.C. (General Visible Emission Standard)	

Visible Emissions Limitation: Visible Emissions Limitation __ of ____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % 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. N/A

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)
   [X] Attached, Document ID: Figure 2-2 [ ] 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: NA [ ] 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)
   [X] Attached, Document ID: Section 5 [ ] 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 ___________
   [X] 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 ___________
   [X] 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: ______________________________

   [X] To be Submitted, Date (if known): : ________
   Test Date(s)/Pollutant(s) Tested: After Start-Up

   [ ] 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: __________ [X] 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)): [x] Attached, Document ID: Section 5 [ ] Not Applicable
2.	Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): [x] Attached, Document ID: Section 6 [ ] Not Applicable
3.	Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) [ ] Attached, Document ID:___________ [X] Not Applicable

Additional Requirements for Title V Air Operation Permit Applications (N/A)

1.	Identification of Applicable Requirements: [ ] Attached, Document ID: ___________
2.	Compliance Assurance Monitoring: [ ] Attached, Document ID: __________ [ ] Not Applicable
3.	Alternative Methods of Operation: [ ] Attached, Document ID: __________ [ ] Not Applicable
4.	Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID: __________ [ ] Not Applicable

Additional Requirements Comment

N/A

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.)

   [X] 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.

   [X] 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: Fugitive Equipment Leaks. Equipment components in VOC service are subject to 40 CFR Part 60 Subpart VVa; therefore components are monitored monthly.

3. Emissions Unit Identification Number: EU016

4. Emissions Unit Status Code: C	5. Commence Construction Date: N/A	6. Initial Startup Date: N/A	7. Emissions Unit Major Group SIC Code: 28

8. Federal Program Applicability: (Check all that apply) N/A

   [ ] Acid Rain Unit

   [ ] CAIR Unit

9. Package Unit:
   Manufacturer: N/A Model Number: N/A

10. Generator Nameplate Rating: N/A MW

11. Emissions Unit Comment:
Equipment components in VOC service are subject to 40 CFR Part 60 Subpart VVa; therefore components are monitored monthly. Control effectiveness is allowed for components subject to an LDAR program.

Emissions Unit Control Equipment/Method: Control 1 of 1

1. Control Equipment/Method Description: Components will be monitored monthly per Subpart VVa. Refer to: Table 5-2, Control Effectiveness for an LDAR Program at a SOCMI Process Unit, Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017, November 1995.
2. Control Device or Method Code: N/A

Emissions Unit Control Equipment/Method: Control __ of __

1. Control Equipment/Method Description: LDAR
2. Control Device or Method Code: 099

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: N/A	
2. Maximum Production Rate: 39,420,000 gallons/yr ethanol	
3. Maximum Heat Input Rate: N/A million Btu/hr	
4. Maximum Incineration Rate: N/A pounds/hr N/A tons/day	
5. Requested Maximum Operating Schedule: 24 hours/day 52 weeks/year	 7 days/week 8,760 hours/year
6. Operating Capacity/Schedule Comment: N/A	

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: N/A	2. Emission Point Type Code: 4

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:
N/A

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:
N/A

5. Discharge Type Code: F	6. Stack Height: N/A feet	7. Exit Diameter: N/A feet
8. Exit Temperature: N/A °F	9. Actual Volumetric Flow Rate: N/A acfm	10. Water Vapor: N/A %

11. Maximum Dry Standard Flow Rate: N/A dscfm	12. Nonstack Emission Point Height: 0 - 20 feet
13. Emission Point UTM Coordinates... Zone: N/A East (km): N/A North (km): N/A	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)

15. Emission Point Comment: N/A

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): Fugitive Emissions from ethanol production		
2. Source Classification Code (SCC): 30125004	3. SCC Units: EACH-YEAR	
4. Maximum Hourly Rate: N/A	5. Maximum Annual Rate: N/A	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: N/A	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: N/A
10. Segment Comment: Equipment components in VOC service are subject to 40 CFR Part 60 Subpart VVa; therefore components are monitored monthly.		

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	N/A	N/A	EL
HAPS	N/A	N/A	NS

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: 0 to 87% (depending on component monitored)
3. Potential Emissions: 4.5 lb/hour 19.6 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A tons/year	
6. Emission Factor: See emission factors in emissions inventory calculations in Appendix B. Reference: Table 2-1, SOCMI Average Emission Factors; or Table 2-11, Default-Zero Values: SOCMI Process Units; or Table 5-1, Summary of Equipment Modifications; Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017, November 1995.	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment:	

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: 0 to 87% (depending on component monitored)
3. Potential Emissions: 0.22 lb/hour 0.98 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A tons/year	
6. Emission Factor: Conservatively assumed equal to 5% of VOC emissions. Reference:	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
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 2

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: Upon Permit Issuance
3. Allowable Emissions and Units: LDAR in compliance with NSPS	4. Equivalent Allowable Emissions: 4.5 lb/hour 19.6 tons/year
5. Method of Compliance: LDAR as specified in 40 CFR 60, Subpart VVa	
6. Allowable Emissions Comment (Description of Operating Method): 40 CFR 60, Subpart VVa and Proposed VOC BACT Emission Limit per 62-212.400(10) F.A.C.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: Upon Permit Issu
3. Allowable Emissions and Units: LDAR in compliance with NSPS	4. Equivalent Allowable Emissions: 0.22 lb/hour 0.98 tons/year
5. Method of Compliance: LDAR as specified in 40 CFR 60, Subpart VVa	
6. Allowable Emissions Comment (Description of Operating Method): 40 CFR 60, Subpart VVa	

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. N/A

Visible Emissions Limitation: Visible Emissions Limitation __ of ____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % 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: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % 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. N/A

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)
   [X] Attached, Document ID: Figure 2-2 [ ] 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: NA [ ] 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)
   [X] Attached, Document ID: Section 5 [ ] 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 ________
   [X] 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 ________
   [X] 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: ________

   [X] To be Submitted, Date (if known): : ________
   Test Date(s)/Pollutant(s) Tested: After Start-Up

   [ ] 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: ________ [X] 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)): [X] Attached, Document ID: Section 5 [ ] Not Applicable
2.	Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): [X] Attached, Document ID: Section 6 [ ] Not Applicable
3.	Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) [ ] Attached, Document ID:________ [X] Not Applicable

Additional Requirements for Title V Air Operation Permit Applications (N/A)

1.	Identification of Applicable Requirements: [ ] Attached, Document ID: ________
2.	Compliance Assurance Monitoring: [ ] Attached, Document ID: ________ [ ] Not Applicable
3.	Alternative Methods of Operation: [ ] Attached, Document ID: ________ [ ] Not Applicable
4.	Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID: ________ [ ] Not Applicable

Additional Requirements Comment

N/A

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.)

   [X] 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.

   [X] 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: Fugitive Dust from Paved Roads. Approximately 60 trucks per day will deliver feedstock using the feedstock roads, and an additional 127 vehicles per day will drive on the plant roads. All roads will be paved with asphalt.

3. Emissions Unit Identification Number: fugitive

4. Emissions Unit Status Code: C	5. Commence Construction Date: N/A	6. Initial Startup Date: N/A	7. Emissions Unit Major Group SIC Code: 28

8. Federal Program Applicability: (Check all that apply) N/A

   [ ] Acid Rain Unit

   [ ] CAIR Unit

9. Package Unit:
   Manufacturer: N/A Model Number: N/A

10. Generator Nameplate Rating: N/A MW

11. Emissions Unit Comment: Approximately 60 trucks per day will be used to deliver feedstock and will use the feedstock roads, and an additional 127 vehicles per day will drive on the plant roads. All roads will be paved with asphalt.

Emissions Unit Control Equipment/Method: Control 1 of 1

1. Control Equipment/Method Description: Pave all roads.	
2. Control Device or Method Code: N/A	

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: 43,264 vehicle miles/yr on paved roads		
2. Maximum Production Rate: N/A		
3. Maximum Heat Input Rate: N/A million Btu/hr		
4. Maximum Incineration Rate: N/A pounds/hr N/A tons/day		
5. Requested Maximum Operating Schedule:	24 hours/day 52 weeks/year	7 days/week 8,760 hours/year
6. Operating Capacity/Schedule Comment: N/A		

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: N/A	2. Emission Point Type Code: 4
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: N/A	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A	

5. Discharge Type Code: F	6. Stack Height: N/A feet	7. Exit Diameter: N/A feet
8. Exit Temperature: N/A °F	9. Actual Volumetric Flow Rate: N/A acfm	10. Water Vapor: N/A %

11. Maximum Dry Standard Flow Rate: N/A dscfm	12. Nonstack Emission Point Height: 0 feet
13. Emission Point UTM Coordinates... Zone: N/A East (km): N/A North (km): N/A	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: N/A	

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): Paved roads – all vehicle types		
2. Source Classification Code (SCC): 30300834	3. SCC Units: Miles	
4. Maximum Hourly Rate: N/A	5. Maximum Annual Rate: 43,264	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: N/A	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: N/A
10. Segment Comment: Approximately 60 trucks per day will be used to deliver feedstock and an additional 127 vehicles per day will drive on the plant roads. All roads will be paved with asphalt.		

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_{10}	N/A	N/A	EL
$PM_{2.5}$	N/A	N/A	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.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: PM_{10}	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 0.1 lb/hour 0.4 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A tons/year	
6. Emission Factor: Paved: 0.020 lbs PM_{10}/VMT (adjusted for estimated rainfall) Reference: EPA, AP-42, Section 13.2.1, Paved Roads, January, 2011.	7. Emissions Method Code: 3
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
11. Potential, Fugitive, and Actual Emissions Comment:	

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: $PM_{2.5}$	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 0.01 lb/hour 0.06 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): N/A tons/year	
6. Emission Factor: Paved: 0.0026 lbs $PM_{2.5}$/VMT (adjusted for estimated rainfall) Reference: EPA, AP-42, Section 13.2.1, Paved Roads, January, 2011.	7. Emissions Method Code: 3
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See emissions inventory calculations in Appendix B.	
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. N/A

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. N/A

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment: N/A	

Visible Emissions Limitation: Visible Emissions Limitation __ of ____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % 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. N/A

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)
   [X] Attached, Document ID: Figure 2-2 [ ] 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: NA [ ] 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)
   [X] Attached, Document ID: Section 5 [ ] 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 ______
   [X] 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 ______
   [X] 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: ______
   [X] To be Submitted, Date (if known): : ______
   Test Date(s)/Pollutant(s) Tested: After Start-Up
   [ ] 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: ______ [X] 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)): [X] Attached, Document ID: Section 5 [ ] Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): [X] Attached, Document ID: Section 6 [ ] Not Applicable
3. Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) [ ] Attached, Document ID:________ [X] Not Applicable

Additional Requirements for Title V Air Operation Permit Applications (N/A)

1. Identification of Applicable Requirements: [ ] Attached, Document ID: ________
2. Compliance Assurance Monitoring: [ ] Attached, Document ID: ________ [ ] Not Applicable
3. Alternative Methods of Operation: [ ] Attached, Document ID: ________ [ ] Not Applicable
4. Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID: ________ [ ] Not Applicable

Additional Requirements Comment

N/A

APPENDIX B
Emissions Calculations

HIGHLANDS ETHANOL, LLC
HIGHLANDS COUNTY, FLORIDA
SUMMARY OF EMISSIONS

Pollutant / CAS No.	PM (tpy)	PM10 (tpy)	PM2.5 (tpy)	SO2 7446-09-5 (tpy)	NOx (tpy)	CO 630-08-0 (tpy)	VOC (tpy)	Total CO2e (tpy)	Non-Bio CO2e (tpy)	HAP (tpy)
POINT EMISSION SOURCES										
REGENERATIVE THERMAL OXIDIZER (RTO)	0.0289	0.0289	0.0289	0.0735	0.460	0.486	21.4	157,649	1,549	8.7
PROCESS AREA EMISSIONS	---	---	---	---	---	---	*21.4*	*156,100*	*0.00*	*8.7*
BURNER COMBUSTION EMISSIONS	*0.0289*	*0.0289*	*0.0289*	*0.0735*	*0.460*	*0.486*	*0.0184*	*1,549*	*1,549*	*0.024*
PRODUCT STORAGE TANK	---	---	---	---	---	---	0.22	---	---	0.0019
DENATURANT STORAGE TANK	---	---	---	---	---	---	0.96	---	---	0.067
MISCELLANEOUS STORAGE SILOS	4.46	4.46	4.46	---	---	---	---	---	---	---
WHEAT BRAN (PROPAGATION NUTRIENT)	*0.47*	*0.47*	*0.47*	---	---	---	---	---	---	---
SOLKA-FLOC® (PROPAGATION NUTRIENT)	*0.47*	*0.47*	*0.47*	---	---	---	---	---	---	---
AMMONIUM SULFATE (PROPAGATION NUTRIENT)	*0.47*	*0.47*	*0.47*	---	---	---	---	---	---	---
POTASSIUM PHOSPHATE (PROPAGATION NUTRIENT)	*0.47*	*0.47*	*0.47*	---	---	---	---	---	---	---
BULK UREA (PROPAGATION NUTRIENT)	*0.47*	*0.47*	*0.47*	---	---	---	---	---	---	---
DISCRETE WHEAT BRAN TRANSFERS (PROPAGATION NUTRIENT)	*0.12*	*0.12*	*0.12*	---	---	---	---	---	---	---
DISCRETE UREA TRANSFERS (PROPAGATION NUTRIENT)	*0.12*	*0.12*	*0.12*	---	---	---	---	---	---	---
ASH (BIOMASS BOILER)	*0.47*	*0.47*	*0.47*	---	---	---	---	---	---	---
HYDRATED LIME SILO (DRY SCRUBBER FOR BIOMASS BOILER)	*0.47*	*0.47*	*0.47*							
SAND (FLUIDIZED BED FOR BIOMASS BOILER)	*0.47*	*0.47*	*0.47*	---	---	---	---	---	---	---
LIMESTONE (FLUIDIZED BED FOR BIOMASS BOILER)	*0.47*	*0.47*	*0.47*	---	---	---	---	---	---	---
BIOGAS BACKUP FLARE (accounts for biogas burned in biomass boiler)	0.002	0.002	0.002	0.0005	0.055	0.30	0.11	94	94	---
COOLING TOWER	1.5	1.5	1.5	---	---	---	9.2	---	---	0.5
STEAM PRODUCTION	13.5	13.5	13.5	73.3	109	134	6.50	362,291	177,918	7.3
BIOMASS BOILER	*11.8*	*11.8*	*11.8*	*71.0*	*94.6*	*118*	*5.91*	*313,238*	*128,864*	*6.6*
GAS BOILER (PEAKING STEAM DEMAND)	*1.66*	*1.66*	*1.66*	*2.33*	*14.6*	*15.4*	*0.583*	*49,054*	*49,054*	*0.77*
STATIONARY ENGINES	0.897	0.897	0.897	0.0331	25.8	15.7	2.87	3,273	3,273	0.078
FIRE PUMP	*0.0699*	*0.0699*	*0.0699*	*0.00258*	*2.01*	*1.22*	*0.224*	*255*	*255*	*0.0061*
EMERGENCY GENERATOR NO. 1	*0.165*	*0.165*	*0.165*	*0.00610*	*4.76*	*2.89*	*0.529*	*604*	*604*	*0.014*
EMERGENCY GENERATOR NO. 2	*0.165*	*0.165*	*0.165*	*0.00610*	*4.76*	*2.89*	*0.529*	*604*	*604*	*0.014*
EMERGENCY GENERATOR NO. 3	*0.165*	*0.165*	*0.165*	*0.00610*	*4.76*	*2.89*	*0.529*	*604*	*604*	*0.014*
EMERGENCY GENERATOR NO. 4	*0.165*	*0.165*	*0.165*	*0.00610*	*4.76*	*2.89*	*0.529*	*604*	*604*	*0.014*
EMERGENCY GENERATOR NO. 5	*0.165*	*0.165*	*0.165*	*0.00610*	*4.76*	*2.89*	*0.529*	*604*	*604*	*0.014*
FUGITIVE EMISSION SOURCES										
STILLAGE LOADOUT	---	---	---	---	---	---	8.4	---	---	---
FUGITIVE EQUIPMENT LEAKS	---	---	---	---	---	---	19.6	---	---	0.98
ROADWAY FUGITIVES	2.3	0.4	0.1	---	---	---	---	---	---	---
Point Source Total	**20.4**	**20.4**	**20.4**	**73.4**	**135.5**	**150.1**	**41.3**	**523,308**	**182,834**	**16.6**
Fugitive Source Total	**2.3**	**0.43**	**0.057**	**0.0**	**0.0**	**0.0**	**28.0**	**0.0**	**0.0**	**0.98**
Facility Total	**22.7**	**20.8**	**20.4**	**73.4**	**135.5**	**150.1**	**69.3**	**523,308**	**182,834**	**17.6**
Major Source Threshold	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**—**	**100,000**	**25**
Significant Emissions Threshold	**25**	**15**	**10**	**40**	**40**	**100**	**40**	**---**	**—**	**—**

HIGHLANDS ETHANOL, LLC
HIGHLANDS COUNTY, FLORIDA
SUMMARY OF EMISSIONS

Pollutant CAS No.	Acetaldehyde 75-07-0 (tpy)	Acrolein 107-02-8 (tpy)	Arsenic 7440-38-2 2.58E-06	Benzene 71-43-2 (tpy)	Beryllium 7440-41-7 (tpy)	Cadmium 7440-43-9 (tpy)	Chromium 7440-47-3 (tpy)	Cobalt 7440-48-4 (tpy)	Cumene 98-82-8 (tpy)
POINT EMISSION SOURCES									
REGENERATIVE THERMAL OXIDIZER (RTO)	7.0	0.0024	0.0000026	0.038	0.0000002	0.000014	0.000018	0.0000011	---
PROCESS AREA EMISSIONS	*7.0*	*0.0024*	---	*0.038*	---	---	---	---	---
BURNER COMBUSTION EMISSIONS	---	---	*0.0000026*	*0.000027*	*0.0000002*	*0.000014*	*0.000018*	*0.0000011*	---
PRODUCT STORAGE TANK	---	---	---	0.00039	---	---	---	---	0.0000028
DENATURANT STORAGE TANK	---	---	---	0.014	---	---	---	---	0.00010
MISCELLANEOUS STORAGE SILOS	---	---	---	---	---	---	---	---	---
WHEAT BRAN (PROPAGATION NUTRIENT)	---	---	---	---	---	---	---	---	---
SOLKA-FLOC® (PROPAGATION NUTRIENT)	---	---	---	---	---	---	---	---	---
AMMONIUM SULFATE (PROPAGATION NUTRIENT)	---	---	---	---	---	---	---	---	---
POTASSIUM PHOSPHATE (PROPAGATION NUTRIENT)	---	---	---	---	---	---	---	---	---
BULK UREA (PROPAGATION NUTRIENT)	---	---	---	---	---	---	---	---	---
DISCRETE WHEAT BRAN TRANSFERS (PROPAGATION NUTRIENT)	---	---	---	---	---	---	---	---	---
DISCRETE UREA TRANSFERS (PROPAGATION NUTRIENT)	---	---	---	---	---	---	---	---	---
ASH (BIOMASS BOILER)	---	---	---	---	---	---	---	---	---
HYDRATED LIME SILO (DRY SCRUBBER FOR BIOMASS BOILER)	---	---	---	---	---	---	---	---	---
SAND (FLUIDIZED BED FOR BIOMASS BOILER)	---	---	---	---	---	---	---	---	---
LIMESTONE (FLUIDIZED BED FOR BIOMASS BOILER)	---	---	---	---	---	---	---	---	---
BIOGAS BACKUP FLARE (accounts for biogas burned in biomass boiler)	---	---	---	---	---	---	---	---	---
COOLING TOWER	0.46	---	---	---	---	---	---	---	---
STEAM PRODUCTION	---	---	0.000296	0.003111	0.000018	0.001630	0.002074	0.000124	---
BIOMASS BOILER	---	---	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	---
GAS BOILER (PEAKING STEAM DEMAND)	---	---	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	---
STATIONARY ENGINES	0.00050	0.00016	---	0.015	---	---	---	---	---
FIRE PUMP	*0.000039*	*0.000012*	---	*0.0012*	---	---	---	---	---
EMERGENCY GENERATOR NO. 1	*0.000092*	*0.000029*	---	*0.0028*	---	---	---	---	---
EMERGENCY GENERATOR NO. 2	*0.000092*	*0.000029*	---	*0.0028*	---	---	---	---	---
EMERGENCY GENERATOR NO. 3	*0.000092*	*0.000029*	---	*0.0028*	---	---	---	---	---
EMERGENCY GENERATOR NO. 4	*0.000092*	*0.000029*	---	*0.0028*	---	---	---	---	---
EMERGENCY GENERATOR NO. 5	*0.000092*	*0.000029*	---	*0.0028*	---	---	---	---	---
FUGITIVE EMISSION SOURCES									
STILLAGE LOADOUT	---	---	---	---	---	---	---	---	---
FUGITIVE EQUIPMENT LEAKS	0.98	---	---	---	---	---	---	---	---
ROADWAY FUGITIVES	---	---	---	---	---	---	---	---	---
Point Source Total	**7.5**	**0.0026**	**0.00030**	**0.070**	**0.000018**	**0.0016**	**0.0021**	**0.00013**	**0.000099**
Fugitive Source Total	**0.98**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Facility Total	**8.4**	**0.0026**	**0.00030**	**0.070**	**0.000018**	**0.0016**	**0.0021**	**0.00013**	**0.000099**
Major Source Threshold	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**
Significant Emissions Threshold	---	---	---	---	---	---	---	---	---

HIGHLANDS ETHANOL, LLC
HIGHLANDS COUNTY, FLORIDA
SUMMARY OF EMISSIONS

Pollutant / CAS No.	Dichlorobenzene 106-46-7 (tpy)	Ethylbenzene 100-41-4 (tpy)	Formaldehyde 50-00-0 (tpy)	n-Hexane 110-54-3 (tpy)	HCl 7647-01-0 (tpy)	Isopropyl Benzene 98-82-8 (tpy)	Lead 7439-92-1 (tpy)
POINT EMISSION SOURCES							
REGENERATIVE THERMAL OXIDIZER (RTO)	0.028	0.0018	0.00097	0.12	---	0.00027	---
PROCESS AREA EMISSIONS	*0.028*	*0.0018*	---	*0.10*	---	*0.00027*	---
BURNER COMBUSTION EMISSIONS	*0.000015*	---	*0.00097*	*0.023*	---	---	---
PRODUCT STORAGE TANK	---	0.000017	---	0.0010	---	---	---
DENATURANT STORAGE TANK	---	0.00058	---	0.036	---	---	---
MISCELLANEOUS STORAGE SILOS	---	---	---	---	---	---	---
WHEAT BRAN (PROPAGATION NUTRIENT)	---	---	---	---	---	---	---
SOLKA-FLOC® (PROPAGATION NUTRIENT)	---	---	---	---	---	---	---
AMMONIUM SULFATE (PROPAGATION NUTRIENT)	---	---	---	---	---	---	---
POTASSIUM PHOSPHATE (PROPAGATION NUTRIENT)	---	---	---	---	---	---	---
BULK UREA (PROPAGATION NUTRIENT)	---	---	---	---	---	---	---
DISCRETE WHEAT BRAN TRANSFERS (PROPAGATION NUTRIENT)	---	---	---	---	---	---	---
DISCRETE UREA TRANSFERS (PROPAGATION NUTRIENT)	---	---	---	---	---	---	---
ASH (BIOMASS BOILER)	---	---	---	---	---	---	---
HYDRATED LIME SILO (DRY SCRUBBER FOR BIOMASS BOILER)	---	---	---	---	---	---	---
SAND (FLUIDIZED BED FOR BIOMASS BOILER)	---	---	---	---	---	---	---
LIMESTONE (FLUIDIZED BED FOR BIOMASS BOILER)	---	---	---	---	---	---	---
BIOGAS BACKUP FLARE (accounts for biogas burned in biomass boiler)	---	---	---	---	---	---	---
COOLING TOWER	---	---	---	---	---	---	---
STEAM PRODUCTION	0.001778	---	0.1111	2.667	6.4	---	0.1
BIOMASS BOILER	*0.00*	---	*0.08*	*1.93*	*6.4*	---	*0.06*
GAS BOILER (PEAKING STEAM DEMAND)	*0.00*	---	*0.03*	*0.73*	---	---	---
STATIONARY ENGINES	---	---	0.0016	---	---	---	---
FIRE PUMP	---	---	*0.00012*	---	---	---	---
EMERGENCY GENERATOR NO. 1	---	---	*0.00029*	---	---	---	---
EMERGENCY GENERATOR NO. 2	---	---	*0.00029*	---	---	---	---
EMERGENCY GENERATOR NO. 3	---	---	*0.00029*	---	---	---	---
EMERGENCY GENERATOR NO. 4	---	---	*0.00029*	---	---	---	---
EMERGENCY GENERATOR NO. 5	---	---	*0.00029*	---	---	---	---
FUGITIVE EMISSION SOURCES							
STILLAGE LOADOUT	---	---	---	---	---	---	---
FUGITIVE EQUIPMENT LEAKS	---	---	---	---	---	---	---
ROADWAY FUGITIVES	---	---	---	---	---	---	---
Point Source Total	**0.030**	**0.0024**	**0.11**	**2.8**	**6.4**	**0.00027**	**0.057**
Fugitive Source Total	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Facility Total	**0.030**	**0.0024**	**0.11**	**2.8**	**6.4**	**0.00027**	**0.057**
Major Source Threshold	**10**	**10**	**10**	**10**	**10**	**10**	**5**
Significant Emissions Threshold	**---**	**---**	**---**	**---**	**---**	**---**	**---**

HIGHLANDS ETHANOL, LLC
HIGHLANDS COUNTY, FLORIDA
SUMMARY OF EMISSIONS

Pollutant CAS No.	Manganese 7439-96-5 (tpy)	Mercury 7439-97-6 (tpy)	Methanol 67-56-1 (tpy)	Methyl Bromide 74-83-9 (tpy)	Methyl Chloride 74-87-3 (tpy)	Naphthalene 91-20-3 (tpy)	Nickel 7440-02-0 (tpy)	Total POM --- (tpy)
POINT EMISSION SOURCES								
REGENERATIVE THERMAL OXIDIZER (RTO)	0.0000049	0.0000033	1.5	0.0098	0.015	0.0000079	0.000027	0.0000011
PROCESS AREA EMISSIONS	---	---	*1.5*	*0.0098*	*0.015*	---	---	---
BURNER COMBUSTION EMISSIONS	*0.0000049*	*0.0000033*	---	---	---	*0.0000079*	*0.000027*	*0.0000011*
PRODUCT STORAGE TANK	---	---	---	---	---	---	---	---
DENATURANT STORAGE TANK	---	---	---	---	---	---	---	---
MISCELLANEOUS STORAGE SILOS	---	---	---	---	---	---	---	---
WHEAT BRAN (PROPAGATION NUTRIENT)	---	---	---	---	---	---	---	---
SOLKA-FLOC® (PROPAGATION NUTRIENT)	---	---	---	---	---	---	---	---
AMMONIUM SULFATE (PROPAGATION NUTRIENT)	---	---	---	---	---	---	---	---
POTASSIUM PHOSPHATE (PROPAGATION NUTRIENT)	---	---	---	---	---	---	---	---
BULK UREA (PROPAGATION NUTRIENT)	---	---	---	---	---	---	---	---
DISCRETE WHEAT BRAN TRANSFERS (PROPAGATION NUTRIENT)	---	---	---	---	---	---	---	---
DISCRETE UREA TRANSFERS (PROPAGATION NUTRIENT)	---	---	---	---	---	---	---	---
ASH (BIOMASS BOILER)	---	---	---	---	---	---	---	---
HYDRATED LIME SILO (DRY SCRUBBER FOR BIOMASS BOILER)	---	---	---	---	---	---	---	---
SAND (FLUIDIZED BED FOR BIOMASS BOILER)	---	---	---	---	---	---	---	---
LIMESTONE (FLUIDIZED BED FOR BIOMASS BOILER)	---	---	---	---	---	---	---	---
BIOGAS BACKUP FLARE (accounts for biogas burned in biomass boiler)	---	---	---	---	---	---	---	---
COOLING TOWER	---	---	---	---	---	---	---	---
STEAM PRODUCTION	0.000563	0.01	---	---	---	0.000904	0.003111	0.2
BIOMASS BOILER	*0.00*	*0.01*	---	---	---	*0.00*	*0.00*	*0.2*
GAS BOILER (PEAKING STEAM DEMAND)	*0.00*	*0.00*	---	---	---	*0.00*	*0.00*	*0.0000360*
STATIONARY ENGINES	---	---	---	---	---	---	---	---
FIRE PUMP	---	---	---	---	---	---	---	---
EMERGENCY GENERATOR NO. 1	---	---	---	---	---	---	---	---
EMERGENCY GENERATOR NO. 2	---	---	---	---	---	---	---	---
EMERGENCY GENERATOR NO. 3	---	---	---	---	---	---	---	---
EMERGENCY GENERATOR NO. 4	---	---	---	---	---	---	---	---
EMERGENCY GENERATOR NO. 5	---	---	---	---	---	---	---	---
FUGITIVE EMISSION SOURCES								
STILLAGE LOADOUT	---	---	---	---	---	---	---	---
FUGITIVE EQUIPMENT LEAKS	---	---	---	---	---	---	---	---
ROADWAY FUGITIVES	---	---	---	---	---	---	---	---
Point Source Total	**0.00057**	**0.012**	**1.5**	**0.010**	**0.015**	**0.00091**	**0.0031**	**0.17**
Fugitive Source Total	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Facility Total	**0.00057**	**0.012**	**1.5**	**0.010**	**0.015**	**0.00091**	**0.0031**	**0.17**
Major Source Threshold	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**
Significant Emissions Threshold	---	---	---	---	---	---	---	---

HIGHLANDS ETHANOL, LLC
HIGHLANDS COUNTY, FLORIDA
SUMMARY OF EMISSIONS

Pollutant CAS No.	Selenium 7782-49-2 (tpy)	Styrene 100-42-5 (tpy)	Toluene 108-88-3 (tpy)	2,2,4-Trimethylpentane 540-84-1 (tpy)	Xylenes 1330-20-7 (tpy)
POINT EMISSION SOURCES					
REGENERATIVE THERMAL OXIDIZER (RTO)	0.0000003	0.027	0.033	0.011	0.027
PROCESS AREA EMISSIONS	---	*0.027*	*0.033*	*0.011*	*0.027*
BURNER COMBUSTION EMISSIONS	*0.0000003*	---	*0.00004*	---	---
PRODUCT STORAGE TANK	---	---	0.00035	0.00012	0.000011
DENATURANT STORAGE TANK	---	---	0.012	0.0040	0.00038
MISCELLANEOUS STORAGE SILOS	---	---	---	---	---
WHEAT BRAN (PROPAGATION NUTRIENT)	---	---	---	---	---
SOLKA-FLOC® (PROPAGATION NUTRIENT)	---	---	---	---	---
AMMONIUM SULFATE (PROPAGATION NUTRIENT)	---	---	---	---	---
POTASSIUM PHOSPHATE (PROPAGATION NUTRIENT)	---	---	---	---	---
BULK UREA (PROPAGATION NUTRIENT)	---	---	---	---	---
DISCRETE WHEAT BRAN TRANSFERS (PROPAGATION NUTRIENT)	---	---	---	---	---
DISCRETE UREA TRANSFERS (PROPAGATION NUTRIENT)	---	---	---	---	---
ASH (BIOMASS BOILER)	---	---	---	---	---
HYDRATED LIME SILO (DRY SCRUBBER FOR BIOMASS BOILER)	---	---	---	---	---
SAND (FLUIDIZED BED FOR BIOMASS BOILER)	---	---	---	---	---
LIMESTONE (FLUIDIZED BED FOR BIOMASS BOILER)	---	---	---	---	---
BIOGAS BACKUP FLARE (accounts for biogas burned in biomass boiler)	---	---	---	---	---
COOLING TOWER	---	---	---	---	---
STEAM PRODUCTION	0.000036	---	0.00504	---	---
BIOMASS BOILER	*0.0*	---	*0.00365*	---	---
GAS BOILER (PEAKING STEAM DEMAND)	*0.0000098*	---	*0.00139*	---	---
STATIONARY ENGINES	---	---	0.055	---	0.0056
FIRE PUMP	---	---	*0.0043*	---	*0.00043*
EMERGENCY GENERATOR NO. 1	---	---	*0.010*	---	*0.0010*
EMERGENCY GENERATOR NO. 2	---	---	*0.010*	---	*0.0010*
EMERGENCY GENERATOR NO. 3	---	---	*0.010*	---	*0.0010*
EMERGENCY GENERATOR NO. 4	---	---	*0.010*	---	*0.0010*
EMERGENCY GENERATOR NO. 5	---	---	*0.010*	---	*0.0010*
FUGITIVE EMISSION SOURCES					
STILLAGE LOADOUT	---	---	---	---	---
FUGITIVE EQUIPMENT LEAKS	---	---	---	---	---
ROADWAY FUGITIVES	---	---	---	---	---
Point Source Total	**0.000036**	**0.027**	**0.11**	**0.015**	**0.033**
Fugitive Source Total	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Facility Total	**0.000036**	**0.027**	**0.11**	**0.015**	**0.033**
Major Source Threshold	**10**	**10**	**10**	**10**	**10**
Significant Emissions Threshold	---	---	---	---	---

HIGHLANDS ETHANOL, LLC
HIGHLANDS COUNTY, FLORIDA
REGENERATIVE THERMAL OXIDIZER (COMBUSTION EMISSIONS)

SOURCE DESCRIPTION

The RTO is fired with natural gas and will be used to control VOC and HAP emissions from several process areas including liquid/solid separation, propagation, fermentation, distillation, product storage shift tanks, and product loadout. This sheet provides the combustion emissions from the RTO's burner. Controlled process VOC emissions are identified on another sheet.

OPERATING PARAMETERS

Boiler

Operating Schedule	8,760	hrs/yr	
Fuels		Natural Gas, Process Area Hydrocarbons	
Capacity	3	MMBtu/hr	
Natural Gas HHV	1,020	Btu/scf	from AP42
Capacity	2,941	scf/hr	
Sulfur Content	0.02	gr/scf	from FDEP
F-Factor	10,610	scf/MMBtu	from 40 CFR 60 Method 19
Exhaust Flow	20,000	acfm	
Exit Temperature	90	°F	
Exit Diameter	3	ft	
Exit Velocity	47.16	ft/s	

EMISSION CALCULATIONS

Criteria Pollutant and GHG Emission Factors for Natural Gas

Pollutant		lb/MMBtu	Emission Factor Source
PM10		0.0022	BACT
PM2.5		0.0022	BACT
SO2		0.0056	BACT
NOx		0.035	BACT
CO		0.037	BACT
VOC		0.0014	BACT
CO2	1	117.6	AP42, Table 1.4-2
CH4	21	0.00225	AP42, Table 1.4-2
N2O	310	0.000627	AP42, Table 1.4-2

Typical Emissions

Typical = RTO Capacity (3 MMBtu/hr) x Emission Factor (lb/MMBtu)

PM10 = *3 MMBtu/hr * 0.0022 lbs/MMBtu*
0.00660 lbs PM/hr

PM2.5 = *3 MMBtu/hr * 0.0022 lbs/MMBtu*
0.00660 lbs PM/hr

SO2 = *3 MMBtu/hr * 0.0055964 lbs/MMBtu*
0.0168 lbs SO2/hr

NOx = *3 MMBtu/hr * 0.035 lbs/MMBtu*
0.105 lbs NOx/hr

CO = *3 MMBtu/hr * 0.037 lbs/MMBtu*

0.111 lbs CO/hr

VOC = *3 MMBtu/hr * 0.0014 lbs/MMBtu*
0.00420 lbs VOC/hr

CO2 = 3 MMBtu/hr x 117.6 lbs/MMBtu
353 lb CO2/hr

CH4 = 3 MMBtu/hr x 0.00225 lbs/MMBtu
0.00676 lb CH4/hr

N2O = 3 MMBtu/hr x 0.000627 lbs/MMBtu
0.00188 lb N2O/hr

CO2e (total) = (353 lb CO2/hr x 1 lb CO2e/lb CO2) + (0.00676 lb CH4/hr x 21 lb CO2e/lb CH4) + (0.00188 lb N2O/hr x 310 lb CO2e/lb N2O)
354 lb CO2e/hr

CO2e (non-biogenic) = (353 lb CO2/hr x 1 lb CO2e/lb CO2) + (0.00676 lb CH4/hr x 21 lb CO2e/lb CH4) + (0.00188 lb N2O/hr x 310 lb CO2e/lb N2O)
354 lb CO2e/hr

Annual Emissions

*Annual = Average (lbs/hr) * 8,760 hrs/yr / 2,000 lbs/ton*

PM10 = *(0.00660 lbs/hr) * (8,760 hrs/yr) / (2,000 lbs/ton)*
0.0289 TPY Total PM10

PM2.5 = *(0.00660 lbs/hr) * (8,760 hrs/yr) / (2,000 lbs/ton)*
0.0289 TPY Filterable PM2.5

SO2 = *(0.0168 lbs/hr) * (8,760 hrs/yr) / (2,000 lbs/ton)*
0.0735 TPY SO2

NOx = *(0.105 lbs/hr) * (8,760 hrs/yr) / (2,000 lbs/ton)*
0.460 TPY NOx

CO = *(0.111 lbs/hr) * (8,760 hrs/yr) / (2,000 lbs/ton)*
0.486 TPY CO

VOC = *(0.00420 lbs/hr) * (8,760 hrs/yr) / (2,000 lbs/ton)*
0.0184 TPY VOC

*CO2e (total) = (354 lbs/hr) * (8,760 hrs/yr) / (2,000 lbs/ton)*
1,549 TPY CO2e

*CO2e (non-biogenic) = (354 lbs/hr) * (8,760 hrs/yr) / (2,000 lbs/ton)*
1,549 TPY CO2e

TOTAL CRITERIA POLLUTANT EMISSIONS SUMMARY

Pollutant	*Typical (lbs/hr)*	*Annual (TPY)*
PM10	0.00660	0.0289
PM2.5	0.00660	0.0289
SO2	0.0168	0.0735
NOx	0.105	0.460
CO	0.111	0.486
VOC	0.00420	0.0184
CO2e (total)	354	1,549
CO2e (non-biogenic)	354	1,549
total HAP	0.0056	0.024

Dispersion Modeling Emissions Summary

Pollutant		*Averaging Period*	*Emissions (lb/hr)*	*Emissions (g/s)*
PM_{10}		24-Hour	0.00660	0.000832
$PM_{2.5}$		24-Hour	0.00660	0.000832
SO_2		1-Hour	0.0168	0.00212
SO_2		3-Hour	0.0168	0.00212
SO_2		24-Hour	0.0168	0.00212
SO_2		Annual	0.0168	0.00212
NO_2		1-Hour	0.105	0.0132
NO_2		Annual	0.105	0.0132
CO		1-Hour	0.111	0.0140
CO		8-Hour	0.111	0.0140

HIGHLANDS ETHANOL, LLC

HIGHLANDS COUNTY, FLORIDA

REGENERATIVE THERMAL OXIDIZER (COMBUSTION EMISSIONS)

TOTAL SPECIATED POLLUTANT EMISSIONS SUMMARY[1]

	lb/MMscf	lb/MMBtu	lb/hr	tpy
HAP	1.89E+00	1.85E-03	5.55E-03	2.43E-02
Organic HAP Speciation				
n-hexane	1.80E+00	1.76E-03	5.29E-03	2.32E-02
formaldehyde	7.50E-02	7.35E-05	2.21E-04	9.66E-04
toluene	3.40E-03	3.33E-06	1.00E-05	4.38E-05
benzene	2.10E-03	2.06E-06	6.18E-06	2.71E-05
dichlorobenzene	1.20E-03	1.18E-06	3.53E-06	1.55E-05
naphthalene	6.10E-04	5.98E-07	1.79E-06	7.86E-06
POM Speciation				
total POM	8.82E-05	8.65E-08	2.59E-07	1.14E-06
2-methylnaphthalene	2.40E-05	2.35E-08	7.06E-08	3.09E-07
phenanthrene	1.70E-05	1.67E-08	5.00E-08	2.19E-07
7,12-dimethylbenz(a)anthracene	1.60E-05	1.57E-08	4.71E-08	2.06E-07
pyrene	5.00E-06	4.90E-09	1.47E-08	6.44E-08
benzo(b,k)fluoranthene	3.60E-06	3.53E-09	1.06E-08	4.64E-08
fluoranthene	3.00E-06	2.94E-09	8.82E-09	3.86E-08
fluorene	2.80E-06	2.75E-09	8.24E-09	3.61E-08
anthracene	2.40E-06	2.35E-09	7.06E-09	3.09E-08
acenaphthene	1.80E-06	1.76E-09	5.29E-09	2.32E-08
acenaphthylene	1.80E-06	1.76E-09	5.29E-09	2.32E-08
benz(a)anthracene	1.80E-06	1.76E-09	5.29E-09	2.32E-08
chrysene	1.80E-06	1.76E-09	5.29E-09	2.32E-08
indeno(1,2,3-cd)pyrene	1.80E-06	1.76E-09	5.29E-09	2.32E-08
3-methylchloranthene	1.80E-06	1.76E-09	5.29E-09	2.32E-08
benzo(a)pyrene	1.20E-06	1.18E-09	3.53E-09	1.55E-08
benzo(g,h,i)perylene	1.20E-06	1.18E-09	3.53E-09	1.55E-08
dibenzo(a,h)anthracene	1.20E-06	1.18E-09	3.53E-09	1.55E-08
Inorganic HAP Speciation				
nickel	2.10E-03	2.06E-06	6.18E-06	2.71E-05
chromium	1.40E-03	1.37E-06	4.12E-06	1.80E-05
cadmium	1.10E-03	1.08E-06	3.24E-06	1.42E-05
manganese	3.80E-04	3.73E-07	1.12E-06	4.90E-06
mercury	2.60E-04	2.55E-07	7.65E-07	3.35E-06
arsenic	2.00E-04	1.96E-07	5.88E-07	2.58E-06
cobalt	8.40E-05	8.24E-08	2.47E-07	1.08E-06
selenium	2.40E-05	2.35E-08	7.06E-08	3.09E-07
beryllium	1.20E-05	1.18E-08	3.53E-08	1.55E-07

REFERENCES/NOTES

1 Emission factors based on EPA AP-42, Section 1.4 *"Natural Gas Combustion"*, July 1998.

HIGHLANDS ETHANOL, LLC
HIGHLANDS COUNTY, FLORIDA
REGENERATIVE THERMAL OXIDIZER (CONTROLLED PROCESS AREA EMISSIONS)

SOURCE DESCRIPTION

The RTO is fired with natural gas and will be used to control VOC and HAP emissions from several process areas including liquid/solid separation, propagation, fermentation, distillation, product storage shift tanks, and product loadout. CO2 emissions from the propagation and fermentation areas also pass through the RTO. This sheet provides the controlled process area emissions from the RTO. Combustion emissions are identified on another sheet.

OPERATING PARAMETERS

Operating Schedule	8,760 hr/yr
VOC Control Efficiency	99.0%

VOC Emissions

Process Area	Pre-Control Emissions (lb/hr)	Pre-Control Emissions (tpy)	Controlled Emissions (lb/hr)	Controlled Emissions (tpy)
Liquid/Solid Separation	7.72	33.8	0.077	0.338
Fermentation	355	1556	3.55	15.6
Distillation	65.2	285	0.65	2.85
Product Storage Shift Tanks	0.016	0.064	0.00016	0.00064
Product Loadout	464	267	4.64	2.67
TOTAL	**892**	**2142**	**8.92**	**21.42**

Total CO2e Emissions

Process Area	Emissions (lb/hr)	Emissions (tpy)
Liquid/Solid Separation	0.00	0.00
Fermentation/Propagation	33,353	146,084
Distillation	2,287	10,016
Product Storage Shift Tanks	0.00	0.00
Product Loadout	0.00	0.00
TOTAL	**35,639**	**156,100**

Non-Biogenic CO2e Emissions

Process Area	Emissions (lb/hr)	Emissions (tpy)
Liquid/Solid Separation	0.00	0.00
Fermentation/Propagation	0.00	0.00
Distillation	0.00	0.00
Product Storage Shift Tanks	0.00	0.00
Product Loadout	0.00	0.00
TOTAL	**0.00**	**0.00**

Total HAP Emissions

Process Area	Pre-Control Emissions (lb/hr)	Pre-Control Emissions (tpy)	Controlled Emissions (lb/hr)	Controlled Emissions (tpy)
Liquid/Solid Separation	1.96E-23	8.58E-23	1.96E-25	8.58E-25
Fermentation/Propagation	161	703	1.61	7.03
Distillation	33.2	145	0.332	1.45
Product Storage Shift Tanks	0.00	0.00	0.00	0.00
Product Loadout	32.2	18.6	0.322	0.186
TOTAL	**226**	**867**	**2.26**	**8.67**

Individual HAP Emissions

Pollutant	Pre-Control Emissions (lb/hr)	Pre-Control Emissions (tpy)	Controlled Emissions (lb/hr)	Controlled Emissions (tpy)
acetaldehyde	160	700	1.60	7.00
methanol	0.599	2.62	0.346	1.52
n-hexane	17.4	10.0	0.174	0.100
benzene	6.54	3.77	0.065	0.0377
toluene	5.80	3.34	0.058	0.0334
1,4-dichlorobenzene	0.000202	0.000884	0.00643	0.0282
styrene	0.00686	0.0300	0.00624	0.0273
m-xylene	0.00424	0.0186	0.00599	0.0262
methyl chloride	0.0000395	0.000173	0.00345	0.0151
2,2,4-trimethylpentane	1.95	1.12	0.0195	0.0112
methyl bromide	0.0000924	0.000405	0.00224	0.00981
acrolein	0.0580	0.254	0.000551	0.00241
ethylbenzene	0.283	0.183	0.00283	0.00183
o-xylene	0.186	0.107	0.00186	0.00107
isopropyl benzene	0.0464	0.0267	0.000464	0.000267

SOURCE DESCRIPTION

VOC and HAP emissions from the hydrolysis and liquid-solid separation areas were estimated by employing process modeling, specifically ASPEN. Emissions presented on this sheet are before RTO control.

OPERATING PARAMETERS

Operating Schedule 8,760 hrs/yr

CALCULATED EMISSIONS [1]

Pollutant	Maximum (lbs./hr)	Annual (TPY)
Total VOC	7.7	34
Total HAP	2.0E-23	8.6E-23
ethanol	1.2E-08	5.1E-08
furfural	0.67	2.9
methylhydroxyfurfural	1.2	5.3
acetaldehyde*	2.0E-23	8.6E-23
ethyl acetate	1.4E-27	6.2E-27
formic acid	0.011	0.048
acetic acid	5.8	26
lactic acid	0.00071	0.0031
isoamyl alcohol	1.5E-17	6.5E-17

REFERENCES/NOTES

1 Based on ASPEN model results.

HIGHLANDS ETHANOL, LLC
HIGHLANDS COUNTY, FLORIDA
FERMENTATION

SOURCE DESCRIPTION

VOC and HAP emission factors for the fermentation area were estimated by employing process modeling, specifically ASPEN. The fermentation area is vented first to an absorber, which recovers ethanol and returns it to the process. Removal of most organic constituents by the absorber is assumed to be negligible. Removal of ethanol, acetaldehyde, and ethyl acetate are based on vendor data. The absorber is in turn vented to the RTO, which achieves 99% destruction efficiency.

OPERATING PARAMETERS

Ethanol Production	4500 gal/hr
Operating Hours	8760 hours per year
RTO	99% removal efficiency

CONTROLLED EMISSIONS SUMMARY

VOC Emissions	15.6 tpy
Total HAP Emissions	7.0 tpy

DETAILED EMISSIONS CALCULATIONS

			Uncontrolled Emission Factor (ASPEN)		Uncontrolled Emissions		Ethanol Absorber			RTO	
Constituent	VOC or HAP?		Primary Fermentation Vent (lb/gal)	Secondary Fermentation Vent (lb/gal)	Vent (lb/hr)	Vent (tpy)	Removal Efficiency (%)	Emissions (lb/hr)	Emissions (tpy)	Emissions (lb/hr)	Emissions (tpy)
Ethanol	VOC		2.63E-01	1.49E+00	7.90E+03	3.46E+04	98%	1.58E+02	6.92E+02	1.58E+00	6.92E+00
Acetaldehyde	VOC	HAP	9.02E-01	8.74E-01	7.99E+03	3.50E+04	32%	1.60E+02	7.00E+02	1.60E+00	7.00E+00
Ethyl Acetate	VOC		3.01E-01	8.41E-02	1.73E+03	7.59E+03	16%	3.46E+01	1.52E+02	3.46E-01	1.52E+00
Isobutanol	VOC		1.35E-03	5.59E-03	3.12E+01	1.37E+02	0%	6.24E-01	2.73E+00	6.24E-03	2.73E-02
Isoamyl Alcohol	VOC		2.33E-03	4.82E-03	3.22E+01	1.41E+02	0%	6.43E-01	2.82E+00	6.43E-03	2.82E-02
Methanol	VOC	HAP	4.53E-03	2.13E-03	3.00E+01	1.31E+02	0%	5.99E-01	2.62E+00	5.99E-03	2.62E-02
Furfural	VOC		2.04E-03	1.79E-03	1.72E+01	7.55E+01	0%	3.45E-01	1.51E+00	3.45E-03	1.51E-02
1-Propanol	VOC		5.45E-04	1.94E-03	1.12E+01	4.91E+01	0%	2.24E-01	9.81E-01	2.24E-03	9.81E-03
Isopropanol	VOC		0.00E+00	6.13E-04	2.76E+00	1.21E+01	0%	5.51E-02	2.41E-01	5.51E-04	2.41E-03
Methane			0.00E+00	9.63E-05	4.34E-01	1.90E+00	0%	8.67E-03	3.80E-02	8.67E-05	3.80E-04
Acetone			1.65E-03	1.16E-04	7.93E+00	3.48E+01	0%	1.59E-01	6.95E-01	1.59E-03	6.95E-03
2-Methylheptane	VOC		2.24E-06		1.01E-02	4.42E-02	0%	2.02E-04	8.84E-04	2.02E-06	8.84E-06
Styrene	VOC	HAP	1.25E-06	7.50E-05	3.43E-01	1.50E+00	0%	6.86E-03	3.00E-02	6.86E-05	3.00E-04
1,4-Dichlorobenzene	VOC	HAP	2.24E-06		1.01E-02	4.42E-02	0%	2.02E-04	8.84E-04	2.02E-06	8.84E-06
m-Xylene*	VOC	HAP		4.71E-05	2.12E-01	9.29E-01	0%	4.24E-03	1.86E-02	4.24E-05	1.86E-04
Ethylbenzene	VOC	HAP		5.64E-05	2.54E-01	1.11E+00	0%	5.07E-03	2.22E-02	5.07E-05	2.22E-04

HIGHLANDS ETHANOL, LLC
HIGHLANDS COUNTY, FLORIDA
FERMENTATION

Propylene	VOC			1.06E-05	4.76E-02	2.08E-01	0%	9.52E-04	4.17E-03	9.52E-06	4.17E-05
Propane	VOC			3.76E-06	1.69E-02	7.42E-02	0%	3.39E-04	1.48E-03	3.39E-06	1.48E-05
Undecane	VOC		1.25E-06	1.14E-05	5.71E-02	2.50E-01	0%	1.14E-03	5.00E-03	1.14E-05	5.00E-05
Toluene	VOC	HAP		6.07E-06	2.73E-02	1.20E-01	0%	5.46E-04	2.39E-03	5.46E-06	2.39E-05
Decane	VOC			9.72E-06	4.37E-02	1.92E-01	0%	8.75E-04	3.83E-03	8.75E-06	3.83E-05
1,4-Diethylbenzene	VOC		7.82E-07	8.08E-07	7.16E-03	3.14E-02	0%	1.43E-04	6.27E-04	1.43E-06	6.27E-06
Benzene	VOC	HAP		8.90E-07	4.01E-03	1.75E-02	0%	8.01E-05	3.51E-04	8.01E-07	3.51E-06
1,2,3-Trimethylbenzene	VOC			5.31E-07	2.39E-03	1.05E-02	0%	4.78E-05	2.09E-04	4.78E-07	2.09E-06
1,2,4-Trimethylbenzene (Pseudocumene)	VOC			5.31E-07	2.39E-03	1.05E-02	0%	4.78E-05	2.09E-04	4.78E-07	2.09E-06
1-Butene	VOC			3.69E-07	1.66E-03	7.28E-03	0%	3.33E-05	1.46E-04	3.33E-07	1.46E-06
Methyl Chloride (Chloromethane)		HAP		4.39E-07	1.97E-03	8.65E-03	0%	3.95E-05	1.73E-04	3.95E-07	1.73E-06
1,2-Dichlorobenzene	VOC			7.92E-07	3.57E-03	1.56E-02	0%	7.13E-05	3.12E-04	7.13E-07	3.12E-06
Methyl Bromide (Bromomethane)		HAP		1.03E-06	4.62E-03	2.02E-02	0%	9.24E-05	4.05E-04	9.24E-07	4.05E-06
Isopentane (2-Methylbutane)	VOC			7.82E-08	3.52E-04	1.54E-03	0%	7.04E-06	3.08E-05	7.04E-08	3.08E-07
c-2-Butene	VOC			2.43E-08	1.10E-04	4.80E-04	0%	2.19E-06	9.60E-06	2.19E-08	9.60E-08
t-2-Butene	VOC			2.09E-08	9.39E-05	4.11E-04	0%	1.88E-06	8.23E-06	1.88E-08	8.23E-08
2,2,4-Trimethylpentane	VOC			4.71E-08	2.12E-04	9.28E-04	0%	4.24E-06	1.86E-05	4.24E-08	1.86E-07
Butane	VOC			9.56E-10	4.30E-06	1.88E-05	0%	8.61E-08	3.77E-07	8.61E-10	3.77E-09
Acetic Acid	VOC		3.45E-04	3.45E-04	3.11E+00	1.36E+01	0%	6.21E-02	2.72E-01	6.21E-04	2.72E-03
Acrolein	VOC	HAP	3.22E-04	3.22E-04	2.90E+00	1.27E+01	0%	5.80E-02	2.54E-01	5.80E-04	2.54E-03
Hydrogen Sulfide			1.95E-04	1.95E-04	1.76E+00	7.70E+00	0%	3.51E-02	1.54E-01	3.51E-04	1.54E-03
Other VOC	VOC		3.13E-04	2.78E-04	2.66E+00	1.16E+01	0%	5.32E-02	2.33E-01	5.32E-04	2.33E-03
VOC			1.48E+00	2.47E+00	1.78E+04	7.78E+04		3.55E+02	1.56E+03	3.55E+00	1.56E+01
HAP			9.07E-01	8.77E-01	8.03E+03	3.52E+04		1.61E+02	7.03E+02	1.61E+00	7.03E+00

HIGHLANDS ETHANOL, LLC
HIGHLANDS COUNTY, FLORIDA
DISTILLATION

SOURCE DESCRIPTION

VOC and HAP emissions from the distillation area were estimated by employing process modeling, specifically ASPEN. Emissions presented on this sheet are before RTO control.

OPERATING PARAMETERS

Operating Schedule 8,760 hrs/yr

CALCULATED EMISSIONS [1]

Pollutant	*Maximum (lbs./hr)*	*Annual (TPY)*
Total VOC	65.2	285
Total HAP	33.2	145
ethanol	4.08	17.9
acetaldehyde*	33.2	145
ethyl acetate	27.9	122

REFERENCES/NOTES

1 Based on ASPEN model results.

SOURCE DESCRIPTION

The facility includes 3 product shift tanks and 1 ethanol product storage tank. The product shift tanks will be vented to the ethanol recovery absorber, and the product storage tank will be designed with an internal floating roof. Emissions are calculated using EPA's TANKS 4.09d software.

OPERATING PARAMETERS

Tank ID. No.	Product Shift Tank No.1	Product Shift Tank No.2	Product Shift Tank No.3	Product Storage Tank
Tank Contents	Ethanol	Ethanol	Ethanol	E95
Tank Type	Internal Floating Roof	Internal Floating Roof	Internal Floating Roof	Internal Floating Roof
Tank Diameter (ft)	18	18	18	40
Tank Height (ft)	22	22	22	51
Tank Capacity (gal)	38,500	38,500	38,500	472,000
Throughput (gal/yr)	13,140,000	13,140,000	13,140,000	41,494,737
Turnovers per Year	341	341	341	88
Max Liquid Height (ft)	21	21	21	#N/A
Avg Liquid Height (ft)	21	21	21	#N/A
Heated Tank	No	No	No	No
Underground Tank	No	No	No	No
Self-Supporting Roof	#N/A	#N/A	#N/A	Yes
Columns	#N/A	#N/A	#N/A	#N/A
Effective Column Diameter	#N/A	#N/A	#N/A	#N/A
Internal Shell Condition	#N/A	#N/A	#N/A	Light Rust
External Shell Color	White	White	White	White
External Shell Shade	White	White	White	White
External Shell Condition	Good	Good	Good	Good
Roof Color	White	White	White	White
Roof Shade	White	White	White	White
Roof Paint Condition	Good	Good	Good	Good
Fixed Roof Type	#N/A	#N/A	#N/A	#N/A
Roof Height (ft)	#N/A	#N/A	#N/A	#N/A
Roof Slope (ft/ft)	#N/A	#N/A	#N/A	#N/A
Breather Vent Vacuum (psig)	#N/A	#N/A	#N/A	#N/A
Breather Vent Pressure (psig)	#N/A	#N/A	#N/A	#N/A
Primary Seal	#N/A	#N/A	#N/A	Liquid Mounted
Secondary Seal	#N/A	#N/A	#N/A	Rim Mounted
Deck Type	#N/A	#N/A	#N/A	Welded
Deck Fittings	#N/A	#N/A	#N/A	Typical
Vent Height above grade (ft)	23	23	23	52
Vent Diameter (ft)	0.25	0.25	0.25	0.25
Exit Velocity (ft/s)	10	10	10	10

HIGHLANDS ETHANOL, LLC

HIGHLANDS COUNTY, FLORIDA

ETHANOL STORAGE TANKS

Nearest Major City	West Palm Beach, FL	West Palm Beach, FL	West Palm Beach, FL	West Palm Beach, FL
Daily Avg Temp (F)	74.72	74.72	74.72	74.72
Annual Avg Max Temp (F)	82.86	82.86	82.86	82.86
Annual Avg Min Temp (F)	66.58	66.58	66.58	66.58
Avg Wind Speed (mph)	9.61	9.61	9.61	9.61
Annual Avg Insolation (Btu/ft2-day)	1,505	1,505	1,505	1,505
Atmospheric Pressure (psia)	14.747	14.747	14.747	14.747
Liquid Molecular Weight	46.07	46.07	46.07	47.25
Vapor Molecular Weight	46.07	46.07	46.07	49.04
Liquid Density @ 60F (lb/gal)	6.61	6.61	6.61	6.55
Avg Bulk Temp (F)	74.74	74.74	74.74	74.74
Avg Surface Temp (F)	76.75	76.75	76.75	76.75
Vapor Pressure (psia)	1.145	1.145	1.145	1.337

VOC EMISSION CALCULATIONS [1]

Tank ID. No.	Product Shift Tank No.1	Product Shift Tank No.2	Product Shift Tank No.3	Product Storage Tank
EIQ No.				
Standing Loss (lbs/yr)	53.0241	53.0241	53.0241	---
Working Loss (lbs/yr)	4201.4735	4201.4735	4201.4735	---
Rim Seal Loss (lbs/yr)	---	---	---	13.98
Withdrawal Losses (lbs/yr)	---	---	---	228.87
Deck Fitting Losses (lbs/yr)	---	---	---	189.96
Deck Seam Losses (lbs/yr)	---	---	---	0.00
Total Losses (tons/yr)	2.13	2.13	2.13	0.22

ETHANOL EMISSION CALCULATIONS [1]

Tank ID. No.	Product Shift Tank No.1	Product Shift Tank No.2	Product Shift Tank No.3	Product Storage Tank
Standing Loss (lbs/yr)	53.0241	53.0241	53.0241	---
Working Loss (lbs/yr)	4201.4735	4201.4735	4201.4735	---
Rim Seal Loss (lbs/yr)	---	---	---	10.96
Withdrawal Losses (lbs/yr)	---	---	---	217.43
Deck Fitting Losses (lbs/yr)	---	---	---	148.87
Deck Seam Losses (lbs/yr)	---	---	---	0.00
Total Losses (tons/yr)	2.13	2.13	2.13	0.19

HIGHLANDS ETHANOL, LLC

HIGHLANDS COUNTY, FLORIDA

ETHANOL STORAGE TANKS

Emissions Summary (Total Emissions from Product Storage Tank - Vent for Product Shift Tanks is Directed to Ethanol Recovery)

Pollutant	***Average (lbs./hr)***	***Maximum [2] (lbs./hr)***	***Annual (TPY)***
VOC	0.049	0.052	0.22
HAP	0.00044	0.00093	0.0019
Ethanol	0.043	0.046	0.19

Emissions Speciation [3]

Pollutant	CAS No.	Percent	HAP
BENZENE	71-43-2	1.41	Yes
BUTANE N-	106-97-8	28.53	No
BUTENE CIS-2-	590-18-1	0.83	No
BUTENE TRANS-2-	624-64-6	1.02	No
CIS-2-PENTENE	627-20-3	0.67	No
CYCLOHEXANE	110-82-7	0.43	No
CYCLOPENTANE	287-92-3	0.61	No
DIMETHYLBUTANE 2,2-	75-83-2	1.04	No
DIMETHYLPENTANE 2,4-	108-08-7	0.43	No
ETHANE	74-84-0	0.07	No
ETHYLBENZENE	100-41-4	0.06	Yes
HEPTANE N-	142-82-5	0.40	No
HEXANE N-	110-54-3	3.75	Yes
ISOBUTANE	75-28-5	8.34	No
ISOPROPYL BENZENE	98-82-8	0.01	Yes
METHYLCYCLOHEXANE	108-87-2	0.12	No
METHYLCYCLOPENTANE	96-37-7	1.41	No
METHYLHEPTANE 3-	589-81-1	0.06	No
METHYLHEXANE 3-	589-34-4	0.42	No
METHYLPENTANE 3-	96-14-0	1.99	No
OCTANE N-	111-65-9	0.03	No
PENTANE N-	109-66-0	7.25	No
PENTENE 1-	109-67-1	0.86	No
PROPANE	74-98-6	1.06	No
TOLUENE	108-88-3	1.25	Yes
TRANS-2-PENTENE	646-04-8	1.37	No
TRIMETHYLBENZENE 1,2,4-	95-63-6	0.05	No
TRIMETHYLBENZENE 1,3,5-	108-67-8	0.02	No
TRIMETHYLPENTANE 2,2,4-	540-84-1	0.42	Yes
TRIMETHYLPENTANE 2,3,4-	565-75-3	0.07	No
XYLENE O-	95-47-6	0.04	Yes
UNIDENTIFIED VOC		35.98	No

HIGHLANDS ETHANOL, LLC
HIGHLANDS COUNTY, FLORIDA
ETHANOL STORAGE TANKS

Speciated Emissions

Pollutant	Average (lb/hr)	Maximum (lb/hr)	Annual (tpy)
BENZENE	**8.94E-05**	**1.89E-04**	**3.92E-04**
BUTANE N-	1.81E-03	3.83E-03	7.93E-03
BUTENE CIS-2-	5.26E-05	1.12E-04	2.31E-04
BUTENE TRANS-2-	6.47E-05	1.37E-04	2.83E-04
CIS-2-PENTENE	4.25E-05	9.00E-05	1.86E-04
CYCLOHEXANE	2.73E-05	5.78E-05	1.19E-04
CYCLOPENTANE	3.87E-05	8.20E-05	1.69E-04
DIMETHYLBUTANE 2,2-	6.60E-05	1.40E-04	2.89E-04
DIMETHYLPENTANE 2,4-	2.73E-05	5.78E-05	1.19E-04
ETHANE	4.44E-06	9.41E-06	1.94E-05
ETHYLBENZENE	**3.81E-06**	**8.06E-06**	**1.67E-05**
HEPTANE N-	2.54E-05	5.37E-05	1.11E-04
HEXANE N-	**2.38E-04**	**5.04E-04**	**1.04E-03**
ISOBUTANE	5.29E-04	1.12E-03	2.32E-03
ISOPROPYL BENZENE	**6.34E-07**	**1.34E-06**	**2.78E-06**
METHYLCYCLOHEXANE	7.61E-06	1.61E-05	3.33E-05
METHYLCYCLOPENTANE	8.94E-05	1.89E-04	3.92E-04
METHYLHEPTANE 3-	3.81E-06	8.06E-06	1.67E-05
METHYLHEXANE 3-	2.66E-05	5.64E-05	1.17E-04
METHYLPENTANE 3-	1.26E-04	2.67E-04	5.53E-04
OCTANE N-	1.90E-06	4.03E-06	8.33E-06
PENTANE N-	4.60E-04	9.74E-04	2.01E-03
PENTENE 1-	5.45E-05	1.16E-04	2.39E-04
PROPANE	6.72E-05	1.42E-04	2.94E-04
TOLUENE	**7.93E-05**	**1.68E-04**	**3.47E-04**
TRANS-2-PENTENE	8.69E-05	1.84E-04	3.81E-04
TRIMETHYLBENZENE 1,2,4-	3.17E-06	6.72E-06	1.39E-05
TRIMETHYLBENZENE 1,3,5-	1.27E-06	2.69E-06	5.56E-06
TRIMETHYLPENTANE 2,2,4-	**2.66E-05**	**5.64E-05**	**1.17E-04**
TRIMETHYLPENTANE 2,3,4-	4.44E-06	9.41E-06	1.94E-05
XYLENE O-	**2.54E-06**	**5.37E-06**	**1.11E-05**
UNIDENTIFIED VOC	2.28E-03	4.83E-03	9.99E-03

REFERENCES/NOTES

1 Emissions were calculated using EPA TANKS 4.09d Program.
2 Maximum emissions are based on emissions during the month of July.
3 Speciation derived from EPA's SPECIATE 3.2 Program, Profile 2490.

HIGHLANDS ETHANOL, LLC
HIGHLANDS COUNTY, FLORIDA
DENATURANT STORAGE TANK

SOURCE DESCRIPTION

The facility includes 1 gasoline storage tank. Gasoline is used as a denaturant to render the ethanol undrinkable. The tank is designed with an internal floating roof to minimize VOC (gasoline) emissions. Emissions are calculated using EPA's TANKS 4.09d software.

OPERATING PARAMETERS

Tank ID. No.	Denaturant Tank
Tank Contents	Gasoline (RVP12)
Tank Type	Internal Floating Roof
Tank Diameter (ft)	15
Tank Height (ft)	16
Tank Capacity (gal)	13,500
Throughput (gal/yr)	2,074,737
Turnovers per Year	154
Max Liquid Height (ft)	#N/A
Avg Liquid Height (ft)	#N/A
Heated Tank	No
Underground Tank	No
Self-Supporting Roof	Yes
Columns	#N/A
Effective Column Diameter	#N/A
Internal Shell Condition	Light Rust
External Shell Color	White
External Shell Shade	White
External Shell Condition	Good
Roof Color	White
Roof Shade	White
Roof Paint Condition	Good
Fixed Roof Type	#N/A
Roof Height (ft)	#N/A
Roof Slope (ft/ft)	#N/A
Breather Vent Vacuum (psig)	#N/A
Breather Vent Pressure (psig)	#N/A
Primary Seal	Liquid Mounted
Secondary Seal	Rim Mounted
Deck Type	Welded
Deck Fittings	Typical
Vent Height above grade (ft)	17
Vent Diameter (ft)	0.25
Exit Velocity (ft/s)	10
Nearest Major City	West Palm Beach, FL
Daily Avg Temp (F)	74.72
Annual Avg Max Temp (F)	82.86
Annual Avg Min Temp (F)	66.58
Avg Wind Speed (mph)	9.61
Annual Avg Insolation (Btu/ft2-day)	1,505
Atmospheric Pressure (psia)	14.747
Liquid Molecular Weight	92.00
Vapor Molecular Weight	64.00
Liquid Density @ 60F (lb/gal)	5.60
Avg Bulk Temp (F)	74.74
Avg Surface Temp (F)	76.75
Vapor Pressure (psia)	8.63

HIGHLANDS ETHANOL, LLC
HIGHLANDS COUNTY, FLORIDA
DENATURANT STORAGE TANK

EMISSION CALCULATIONS [1]

Tank ID. No.	Denaturant Tank
Standing Loss (lbs/yr)	---
Working Loss (lbs/yr)	---
Rim Seal Loss (lbs/yr)	74.88
Withdrawal Losses (lbs/yr)	21.74
Deck Fitting Losses (lbs/yr)	1822.14
Deck Seam Losses (lbs/yr)	0.00
Total Losses (tons/yr)	0.96

Emissions Summary (Total VOC Emissions from all tanks)

Pollutant	*Average (lbs./hr)*	*Maximum [2] (lbs./hr)*	*Annual (TPY)*
VOC	0.22	0.23	0.96
Total HAP	0.015	0.016	0.067

Emissions Speciation [3]

Pollutant	CAS No.	Percent	HAP
BENZENE	71-43-2	1.41	Yes
BUTANE N-	106-97-8	28.53	No
BUTENE CIS-2-	590-18-1	0.83	No
BUTENE TRANS-2-	624-64-6	1.02	No
CIS-2-PENTENE	627-20-3	0.67	No
CYCLOHEXANE	110-82-7	0.43	No
CYCLOPENTANE	287-92-3	0.61	No
DIMETHYLBUTANE 2,2-	75-83-2	1.04	No
DIMETHYLPENTANE 2,4-	108-08-7	0.43	No
ETHANE	74-84-0	0.07	No
ETHYLBENZENE	100-41-4	0.06	Yes
HEPTANE N-	142-82-5	0.40	No
HEXANE N-	110-54-3	3.75	Yes
ISOBUTANE	75-28-5	8.34	No
ISOPROPYL BENZENE	98-82-8	0.01	Yes
METHYLCYCLOHEXANE	108-87-2	0.12	No
METHYLCYCLOPENTANE	96-37-7	1.41	No
METHYLHEPTANE 3-	589-81-1	0.06	No
METHYLHEXANE 3-	589-34-4	0.42	No
METHYLPENTANE 3-	96-14-0	1.99	No
OCTANE N-	111-65-9	0.03	No
PENTANE N-	109-66-0	7.25	No
PENTENE 1-	109-67-1	0.86	No
PROPANE	74-98-6	1.06	No
TOLUENE	108-88-3	1.25	Yes
TRANS-2-PENTENE	646-04-8	1.37	No
TRIMETHYLBENZENE 1,2,4-	95-63-6	0.05	No
TRIMETHYLBENZENE 1,3,5-	108-67-8	0.02	No
TRIMETHYLPENTANE 2,2,4-	540-84-1	0.42	Yes
TRIMETHYLPENTANE 2,3,4-	565-75-3	0.07	No
XYLENE O-	95-47-6	0.04	Yes
UNIDENTIFIED VOC		35.98	No

HIGHLANDS ETHANOL, LLC
HIGHLANDS COUNTY, FLORIDA
DENATURANT STORAGE TANK

Speciated Emissions

Pollutant	Average (lb/hr)	Maximum (lb/hr)	Annual (tpy)
BENZENE	**3.09E-03**	**3.22E-03**	**1.35E-02**
BUTANE N-	6.25E-02	6.51E-02	2.74E-01
BUTENE CIS-2-	1.82E-03	1.89E-03	7.96E-03
BUTENE TRANS-2-	2.23E-03	2.33E-03	9.79E-03
CIS-2-PENTENE	1.47E-03	1.53E-03	6.43E-03
CYCLOHEXANE	9.42E-04	9.82E-04	4.13E-03
CYCLOPENTANE	1.34E-03	1.39E-03	5.85E-03
DIMETHYLBUTANE 2,2-	2.28E-03	2.37E-03	9.98E-03
DIMETHYLPENTANE 2,4-	9.42E-04	9.82E-04	4.13E-03
ETHANE	1.53E-04	1.60E-04	6.72E-04
ETHYLBENZENE	**1.31E-04**	**1.37E-04**	**5.76E-04**
HEPTANE N-	8.76E-04	9.13E-04	3.84E-03
HEXANE N-	**8.21E-03**	**8.56E-03**	**3.60E-02**
ISOBUTANE	1.83E-02	1.90E-02	8.00E-02
ISOPROPYL BENZENE	**2.19E-05**	**2.28E-05**	**9.59E-05**
METHYLCYCLOHEXANE	2.63E-04	2.74E-04	1.15E-03
METHYLCYCLOPENTANE	3.09E-03	3.22E-03	1.35E-02
METHYLHEPTANE 3-	1.31E-04	1.37E-04	5.76E-04
METHYLHEXANE 3-	9.20E-04	9.59E-04	4.03E-03
METHYLPENTANE 3-	4.36E-03	4.54E-03	1.91E-02
OCTANE N-	6.57E-05	6.85E-05	2.88E-04
PENTANE N-	1.59E-02	1.65E-02	6.96E-02
PENTENE 1-	1.88E-03	1.96E-03	8.25E-03
PROPANE	2.32E-03	2.42E-03	1.02E-02
TOLUENE	**2.74E-03**	**2.85E-03**	**1.20E-02**
TRANS-2-PENTENE	3.00E-03	3.13E-03	1.31E-02
TRIMETHYLBENZENE 1,2,4-	1.10E-04	1.14E-04	4.80E-04
TRIMETHYLBENZENE 1,3,5-	4.38E-05	4.57E-05	1.92E-04
TRIMETHYLPENTANE 2,2,4-	**9.20E-04**	**9.59E-04**	**4.03E-03**
TRIMETHYLPENTANE 2,3,4-	1.53E-04	1.60E-04	6.72E-04
XYLENE O-	**8.76E-05**	**9.13E-05**	**3.84E-04**
UNIDENTIFIED VOC	7.88E-02	8.21E-02	3.45E-01

REFERENCES/NOTES

1 Emissions were calculated using EPA TANKS 4.09d Program.
2 Maximum emissions are based on emissions during the month of July.
3 Speciation derived from EPA's SPECIATE 3.2 Program, Profile 2490.

HIGHLANDS ETHANOL, LLC
HIGHLANDS COUNTY, FLORIDA
PRODUCT LOADOUT

SOURCE DESCRIPTION

Denatured ethanol product will be loaded onto trucks which will not be in dedicated service. Emissions from the process will be directed to the plant RTO for control. Emissions shown on this sheet are before RTO control.

OPERATING PARAMETERS

Operating Schedule	8,760	hrs/yr	
Design Thruput	36	Mgallons/hr	assume 600 gpm truck filling rate
Annual Thruput	41,495	Mgallons/Yr	E95 (ethanol plus denaturant)

EMISSION CALCULATIONS

VOC Loading Emissions [1]

L (lbs/Mgal) = (12.46 x S x P x M)/T

where:
L = Loading Loss, lb VOC/Mgal of liquid loaded
S = Saturation Factor (AP-42 Table 5.2-1)
P = True Vapor Pressure of Liquid Loaded, psia
M = Molecular Weight of Vapors, lb/lb-mole
T = Temperature of Bulk Liquid Loaded, ^{o}R

The values for P, T, and M were obtained from EPA's TANKS 4.09c emissions calculation software, which calculates the annual average bulk product temperature based on the annual average temperatures for the city of West Palm Beach, Florida. The saturation factor is based on submerged loading, dedicated vapor balance service for gasoline. This should be conservative because the vapor pressure of ethanol is less than that for gasoline and because the trucks will not be in dedicated gasoline service.

Saturation Factor(s)	1
Annual Thruput	41,495 Mgal/yr
Vapor Molecular Weight (MW)	64.00 lb/lb-mole
Product Temperature (T)	534.33 ^{o}R
True Vapor Pressure (P)	8.63 psia *(based on RVP 12 gasoline)*

VOC Emission Factor

*L = (12.46 * 1 * 8.6339 psia * 64 lb/lb-mole) / 534.33 R*
12.89 lb VOC/Mgal

Uncontrolled Emissions

*VOC = 12.89 lb VOC/Mgal * 36 Mgal /hr*
463.87 lb/hr VOC gasoline vapors displaced

VOC = 12.89 lb VOC/Mgal * 41,495 Mgal /yr
267.34 tpy VOC

HIGHLANDS ETHANOL, LLC
HIGHLANDS COUNTY, FLORIDA
PRODUCT LOADOUT

HAP Emissions [2]	lb/hr	tpy
benzene	6.54	3.77
ethylbenzene	0.278	0.160
n-hexane	17.4	10.0
isopropyl benzene	0.0464	0.0267
toluene	5.80	3.34
2,2,4-trimethylpentane	1.95	1.12
o-xylene	0.186	0.107
Total	32.2	18.6

REFERENCES/NOTES

1 Based on EPA AP-42, Section 5.2, Transportation and Marketing of Petroleum Liquids, January 1995.

2 HAP emissions based on speciation shown for denaturant storage, conservatively assuming gasoline vapors.

HIGHLANDS ETHANOL, LLC
HIGHLANDS COUNTY, FLORIDA
MISCELLANEOUS STORAGE SILOS

SOURCE DESCRIPTION

A number of silos are used to handle dry materials. These materials include a number of nutrients for the propagation area and a number of materials associated with the biomass boilers. The vents for each of these silos will be controlled by a bin vent filter that meets BACT emission requirements.

OPERATING PARAMETERS

Emission Source	Stack Height (feet)	Exit Diameter (feet)	Exhaust Flow (acfm)	Exit Velocity (ft/s)	Exhaust Temperature (°F)	BACT Emission Rate (gr/scf)	BACT Emission Rate (lb/hr)	BACT Emission Rate (tpy)
Wheat Bran	48	1.0	2,500	53.05	80	0.005	0.11	0.47
Powdered Cellulose	48	1.0	2,500	53.05	80	0.005	0.11	0.47
Ammonium Sulfate	40	1.0	2,500	53.05	80	0.005	0.11	0.47
Potassium Phosphate	48	1.0	2,500	53.05	80	0.005	0.11	0.47
Bulk Urea	40	1.0	2,500	53.05	80	0.005	0.11	0.47
Discrete Wheat Bran Transfers	35	0.5	650	55.17	70	0.005	0.03	0.12
Discrete Urea Transfers	35	0.5	650	55.17	70	0.005	0.03	0.12
Ash	34	1.5	2,500	23.58	77	0.005	0.1	0.47
Hydrated Lime	34	1.5	2,500	23.58	77	0.005	0.1	0.47
Sand	34	1.5	2,500	23.58	77	0.005	0.1	0.47
Limestone	34	1.5	2,500	23.58	77	0.005	0.1	0.47
						total	1.0	4.5

Notes:
Stack heights referenced as above ground level (AGL).
Stack locations assumed at center of silo.
PM emission rates from dust collector baghouses are based on gr/dscf BACT and exhaust flow.

HIGHLANDS ETHANOL, LLC
HIGHLANDS COUNTY, FLORIDA
BIOGAS BACKUP FLARE

SOURCE DESCRIPTION

A flare is used for combusting methane generated by anaerobic digestion and has a rated capacity of 100 MMBtu/hr. The flare will use natural gas for the pilot and will be limited to combust biogas only when the biomass boiler is shut down. Hence, annual potential emissions include only the pilot because emissions for biogas combustion are accounted for by the biomass boilers.

OPERATING PARAMETERS

Operating Schedule (Pilot)	8,760	hrs/yr	
Natural Gas Heat Rate (Pilot)	0.18	MMBtu/hr	3 scfm gas
Biogas Heat Rate (Flare)	100.0	MMBtu/hr	
H2S Controlled	5.4	lb/hr	scrubber prior to flare
H2S Flare Reduction (minimum)	98%		

EMISSION CALCULATIONS

Combustion Emissions[1]

Emission Factor		lb/MMBtu	µg/l	
H2S (max)		0.0011		
SO2 (max)		0.10		assumes 100% conversion
SO2 (nat. gas)		0.00059		
NOx		0.068		
CO		0.37		
THC		0.14		
PM		0.0024	40	lightly smoking
CO2	1	117		
CH4	21	0.0022		
N2O	320	0.00022		

Emissions During Flare Operation

*Avg = Heat Input (100.0 MMBtu/hr) * Emission Factor (lbs/MMBtu)*

*H2S = 100.0 MMBtu/hr * 0.00108 lb/MMBtu*
0.108 lb/hr H2S

*SO2 = 100.0 MMBtu/hr * 0.102 lb/MMBtu*
10.2 lb/hr SO2

*NOx = 100.0 MMBtu/hr * 0.068 lb/MMBtu*
6.8 lb/hr NOx

*CO = 100.0 MMBtu/hr * 0.37 lb/MMBtu*
37 lb/hr CO

*PM = 100.0 MMBtu/hr * 0.0024 lb/MMBtu*
0.24 lb/hr PM

*THC = 100.0 MMBtu/hr * 0.14 lb/MMBtu*
14.0 lb/hr THC

*CO2 = 100.0 MMBtu/hr * 117 lb/MMBtu*
11,689 lb/hr CO2

*CH4 = 100.0 MMBtu/hr * 0.0022 lb/MMBtu*
0.22 lb/hr CH4

*N2O = 100.0 MMBtu/hr * 0.00022 lb/MMBtu*
0.022 lb/hr CH4

CO2e (total) = (11,689 lb CO2/hr x 1 lb CO2e/lb CO2) + (0.22 lb CH4/hr x 21 lb CO2e/lb CH4)
+ (0.022 lb N2O/hr x 320 lb CO2e/lb N2O)
11,701 lb CO2e/hr

CO2e (non-biogenic) = (0.220 lb CH4/hr x 21 lb CO2e/lb CH4) + (0.0220 lb N2O/hr x 320 lb CO2e/lb N2O)
11.7 lb CO2e/hr

Annual Emissions - Pilot Operation

*Annual = [Pilot Input (0.18 MMBtu/hr) * EF (lbs/MMBtu)] / 2,000 lbs/ton*

*SO2 = [0.18 MMBtu/hr * 0.00059 lb/MMBtu * 8,760 hr/yr] / 2,000 lbs/ton*
0.00047 TPY SOx

*NOx = [0.18 MMBtu/hr * 0.068 lb/MMBtu * 8,760 hr/yr] / 2,000 lbs/ton*
0.055 TPY NOx

*CO = [0.18 MMBtu/hr * 0.37 lb/MMBtu * 8,760 hr/yr] / 2,000 lbs/ton*
0.30 TPY CO

*PM = [0.18 MMBtu/hr * 0.0024 lb/MMBtu * 8,760 hr/yr] / 2,000 lbs/ton*
0.0020 TPY PM

*THC = [0.18 MMBtu/hr * 0.14 lb/MMBtu * 8,760 hr/yr] / 2,000 lbs/ton*
0.11 TPY THC

*CO2 = [0.18 MMBtu/hr * 117 lb/MMBtu * 8,760 hr/yr] / 2,000 lbs/ton*
94 TPY CO2

*CH4 = [0.18 MMBtu/hr * 0.0022 lb/MMBtu * 8,760 hr/yr] / 2,000 lbs/ton*
0.0018 TPY CH4

*N2O = [0.18 MMBtu/hr * 0.00022 lb/MMBtu * 8,760 hr/yr] / 2,000 lbs/ton*
0.00018 TPY N2O

CO2e (total) = (94 ton CO2/yr x 1 ton CO2e/ton CO2) + (0.0018 ton CH4/yr x 21 ton CO2e/ton CH4)
+ (0.00018 ton N2O/yr x 320 ton CO2e/ton N2O)
94 TPY CO2e

CO2e (non-biogenic) = CO2e (total)
94 TPY CO2e

Emissions Summary

Pollutant	*Maximum (lbs./hr)*	*Annual (TPY)*
PM	0.24	0.0020
SO2	10	0.00047
NOx	6.8	0.055
CO	37	0.30
VOC[3]	14.0	0.11
CO2e (total)	11,701	94
CO2e (non-biogenic)	11.7	94

REFERENCES/NOTES

1 Based on EPA AP-42, Section 13.5, Industrial Flares, January 1995.

HIGHLANDS ETHANOL, LLC
HIGHLANDS COUNTY, FLORIDA
COOLING TOWER

SOURCE DESCRIPTION

Cooling for equipment within the facility will be provided by an induced draft cooling tower.

OPERATING PARAMETERS

Operating Schedule	8,760	hrs/yr
Cells	4	
Water Flow (total)	25,038,000	lb/hr cooling water
Water Density	8.346	lb/gal
Water Flow (total)	50,000	gallons/minute (GPM) cooling water
Drift Losses	0.0005	%
TDS [1]	2,750	mg/L
Air Flow (total)	25,282,963	lb/hr air flow
Air Exit Temperature	94.3	°F
Air Density	0.07165	lb/ft3
Air Flow (total)	5,881,420	acfm
Air Flow (each cell)	1,470,355	acfm
Exit Diameter (each cell)	32.8	ft
Exit Velocity (each cell)	28.9	ft/s

EMISSION CALCULATIONS [1]

PM Emissions

*Drift Loss (gal/hr) = 50,000 GPM * 60 mins/hr * 0.0005 %drift*

15.00 gals/hr Drift Loss

Average Emissions

*Average = 15.0 gal/hr loss * 2,750 mg/L * 3.7854 L/gal / 453,600 mg/lb*

0.34 lb PM10/hr

Annual Emissions

*Total = 0.34 lbs/hr * 8,760 hrs/yr / 2,000 lbs/ton*

1.51 TPY PM10

VOC Emissions

SCAQMD Guidance (2006)

Average Emissions

*Average = 50,000 GPM * 0.00144 MGD/GPM * 0.7 lb VOC/MGD / 24 hr/day*

2.10 lb VOC/hr

Annual Emissions

*Total = 2.10 lbs/hr * 8,760 hrs/yr / 2,000 lbs/ton*

9.20 TPY VOC

HIGHLANDS ETHANOL, LLC
HIGHLANDS COUNTY, FLORIDA
COOLING TOWER

Emissions Summary

Pollutant	*Average (lbs/hr)*	*Annual (TPY)*	
PM10	0.34	1.5	
PM2.5	0.34	1.5	assume equal to PM10
VOC	2.1	9.2	
HAP [2]	0.11	0.5	

Dispersion Modeling Emissions Summary, Each Cooling Tower Cell

Pollutant	*Averaging Period*	*Emissions (lb/hr)*
PM_{10}	24-Hour	0.086
PM_{10}	Annual	0.086

REFERENCES/NOTES

1 Based on facility supplied information.
2 HAP emissions are conservatively assumed to represent 5% of the VOC emissions, and are conservatively assigned to acetaldehyde.

HIGHLANDS ETHANOL, LLC
HIGHLANDS COUNTY, FLORIDA
BIOMASS BOILER

SOURCE DESCRIPTION

The project includes a single fluidized bed biomass boiler with a rated capacity of 270 MMBtu/hr. The unit will burn stillage cake, biosolids, biogas and natural gas, and will supply baseload process steam to the facility. Some of the steam produced by the boiler will be used to produce 7.6 MW of power. The unit will utilize best available control technology (BACT) to minimize emissions. Specifically, the boiler will be equipped with a baghouse to control PM emissions, selective non-catalytic reduction (SNCR) to control NOx emissions, and limestone injection and a scrubber to control SO2 emissions. Good combustion practices will be used to minimize CO and VOC emissions.

OPERATING PARAMETERS

Operating Schedule	8,760	Hrs/yr		
Total Capacity	270	MMBtu/hr		
Biomass Capacity	170	MMBtu/hr	stillage cake and biosolids	
Biogas Capacity	100	MMBtu/hr		
Natural Gas Capacity	250	MMBtu/hr		
Biomass F-Factor (approx.)	16,500	wscf/MMBtu	9,600	dscf/MMBtu
Biogas F-Factor (approx.)	9,400	wscf/MMBtu	8,710	dscf/MMBtu
Natural Gas F-Factor (approx.)	10,610	wscf/MMBtu	8,710	dscf/MMBtu
Natural Gas HHV	1,020	Btu/scf	from AP42	
Exhaust Flow	75,073	acfm		
Exit Temperature	175	°F		
Exit Diameter	7	ft		
Exit Velocity	32.5	ft/s		

EMISSION CALCULATIONS

Emission Factors[1]		lbs/MMBtu	
PM10 (filterable)		0.01	
PM10 (total)		0.05	
PM2.5 (filterable)		0.01	
PM2.5 (total)		0.05	
SO_2		0.06	30-day rolling average
SO_2		0.12	short-term average (24-hour)
SO_2		0.14	short-term average (3-hour)
NOx		0.08	30-day rolling average
NOx		0.1	short-term average (24-hour)
CO		0.1	30-day rolling average
CO		0.2	short-term average (8-hour)
VOC		0.005	
CO2 (stillage)	1	260.5	40 CFR 98, Table C-1
CO2 (nat. gas)	1	117.6	AP42, Table 1.4-2
CH4 (stillage)	21	0.0705	40 CFR 98, Table C-1
CH4 (nat. gas)	21	0.00225	AP42, Table 1.4-2
N2O (stillage)	310	0.00926	40 CFR 98, Table C-1
N2O (nat. gas)	310	0.000627	AP42, Table 1.4-2
HCl		0.0054	
Pb		0.000048	
Hg		0.00001	
NH3		0.013	

Typical Emissions

Typical = Boiler Capacity (270 MMBtu/hr) x Emission Factor (lb/MMBtu)

Filterable PM10 = 270 MMBtu/hr x 0.01 lb/MMBtu
2.70 lb Filterable PM10/hr

Total PM10 = 270 MMBtu/hr x 0.05 lb/MMBtu
13.5 lb Total PM10/hr

Filterable PM2.5 = 270 MMBtu/hr x 0.01 lb/MMBtu
2.70 lb Filterable PM2.5/hr

Total PM2.5 = 270 MMBtu/hr x 0.05 lb/MMBtu
13.5 lb Total PM2.5/hr

SO2 = 270 MMBtu/hr x 0.06 lbs/MMBtu
16.2 lb SO2/hr

NOx = 270 MMBtu/hr x 0.08 lbs/MMBtu
21.6 lb NOx/hr

CO = 270 MMBtu/hr x 0.1 lbs/MMBtu
27.0 lb CO/hr

VOC = 270 MMBtu/hr x 0.005 lbs/MMBtu
1.35 lb VOC/hr

CO2 = 270 MMBtu/hr x 260.5 lbs/MMBtu
70,340 lb CO2/hr

CH4 = 270 MMBtu/hr x 0.071 lbs/MMBtu
19.0 lb CH4/hr

N2O = 270 MMBtu/hr x 0.0093 lbs/MMBtu
2.50 lb N2O/hr

CO2e (total) = (70,340 lb CO2/hr x 1 lb CO2e/lb CO2) + (19.0 lb CH4/hr x 21 lb CO2e/lb CH4
+ (2.50 lb N2O/hr x 310 lb CO2e/lb N2O)
71,515 lb CO2e/hr

CO2e (non-biogenic) = (19.0 lb CH4/hr x 21 lb CO2e/lb CH4) + (2.50 lb N2O/hr x 310 lb CO2e/lb N2O
1,175 lb CO2e/hr

HCl = 270 MMBtu/hr x 0.0054 lbs/MMBtu
1.46 lb HCl/hr

Pb = 270 MMBtu/hr x 0.000048 lbs/MMBtu
1.30E-02 lb Pb/hr

Hg = 270 MMBtu/hr x 0.00001 lbs/MMBtu
2.70E-03 lb Hg/hr

NH3 = 270 MMBtu/hr x 0.013 lbs/MMBtu
3.44 lb NH3/hr

GHG Emissions - During Worst-Case Fossil Fuel Firing

CO2 = 20 MMBtu/hr x 260.5 lbs/MMBtu + 250 MMBtu/hr x 117.6 lbs/MMBtu
34,622 lb CO2/hr

CO2 (fossil) = 250 MMBtu/hr x 117.6 lbs/MMBtu
29,412 lb CO2/hr

CH4 = 20 MMBtu/hr x 0.0705 lbs/MMBtu + 250 MMBtu/hr x 0.00225 lbs/MMBtu
2.0 lb CH4/hr

N2O = 20 MMBtu/hr x 0.00926 lbs/MMBtu + 250 MMBtu/hr x 0.000627 lbs/MMBtu
0.34 lb N2O/hr

CO2e (total) = (34,622 lb CO2/hr x 1 lb CO2e/lb CO2) + (2.0 lb CH4/hr x 21 lb CO2e/lb CH4)
+ (0.34 lb N2O/hr x 310 lb CO2e/lb N2O)
34,770 lb CO2e/hr

CO2e (non-biogenic) = (29,412 lb CO2/hr x 1 lb CO2e/lb CO2) + (2.0 lb CH4/hr x 21 lb CO2e/lb CH4)
+ (0.34 lb N2O/hr x 310 lb CO2e/lb N2O)
29,421 lb CO2e/hr

Annual Emissions

*Annual = Average (lbs/hr) * 8,760 hrs/yr / 2,000 lbs/ton*

*Filterable PM10 = (2.70 lbs/hr) * (8,760 hrs/yr) / (2,000 lbs/ton)*
11.8 TPY Filterable PM10

*Total PM10 = (13.5 lbs/hr) * (8,760 hrs/yr) / (2,000 lbs/ton)*
59.1 TPY Total PM10

*Filterble PM2.5 = (2.70 lbs/hr) * (8,760 hrs/yr) / (2,000 lbs/ton)*
11.8 TPY Filterable PM2.5

*Total PM2.5 = (13.5 lbs/hr) * (75,073 hrs/yr) / (2,000 lbs/ton)*
59.1 TPY Total PM2.5

*SO2 = (16.2 lbs/hr) * (8,760 hrs/yr) / (2,000 lbs/ton)*
71.0 TPY SO2

*NOx = (21.6 lbs/hr) * (8,760 hrs/yr) / (2,000 lbs/ton)*
95 TPY NOx

*CO = (27.0 lbs/hr) * (8,760 hrs/yr) / (2,000 lbs/ton)*
118 TPY CO

*VOC = (1.35 lbs/hr) * (8,760 hrs/yr) / (2,000 lbs/ton)*
5.91 TPY VOC

*CO2e (total) = (71,515 lbs/hr) * (8,760 hrs/yr) / (2,000 lbs/ton)*
313,238 TPY CO2e

*CO2e (non-biogenic) = (29,421 lbs/hr) * (8,760 hrs/yr) / (2,000 lbs/ton)*
128,864 TPY CO2e

*HCl = (1.46 lbs/hr) * (8,760 hrs/yr) / (2,000 lbs/ton)*
6.39 TPY HCl

*Pb = (0.01296 lbs/hr) * (8,760 hrs/yr) / (2,000 lbs/ton)*
5.68E-02 TPY Pb

*Hg = (0.0027 lbs/hr) * (8,760 hrs/yr) / (2,000 lbs/ton)*
1.18E-02 TPY Hg

*NH3 = (3.44 lbs/hr) * (8,760 hrs/yr) / (2,000 lbs/ton)*
15.1 TPY Hg

Emissions Summary

Pollutant	***Typical (lbs/hr)***	***Annual (TPY)***
Filterable PM10	2.70	11.8
Total PM10	13.5	59.1
Filterable PM2.5	2.70	11.8
Total PM2.5	13.5	59.1
SO_2	16.2	71.0
NOx	21.6	95
CO	27.0	118
VOC	1.35	5.91
CO2e (total)	71,515	313,238
CO2e (non-biogenic)	29,421	128,864
HCl	1.46	6.39
Pb	0.0130	0.0568
Hg	0.00270	0.0118
total HAPs	1.50	6.57
NH3	3.44	15.1

Dispersion Modeling Emissions Summary

Pollutant	***Averaging Period***	***Emissions (lb/hr)***	***Emissions (g/s)***
PM_{10}	24-Hour	13.5	1.70
PM_{10}	Annual	13.5	1.70
$PM_{2.5}$	24-Hour	13.5	1.70
$PM_{2.5}$	Annual	13.5	1.70
SO_2	1-Hour	37.8	4.76
SO_2	3-Hour	37.8	4.76
SO_2	24-Hour	37.8	4.76
SO_2	Annual	37.8	4.76
NO_2	1-Hour	27.0	3.40
NO_2	Annual	27.0	3.40
CO	1-Hour	54.0	6.80
CO	8-Hour	54.0	6.80

TOTAL SPECIATED POLLUTANT EMISSIONS SUMMARY[2,3]

The maximum potential HAP emissions of biomass or natural gas are used for purposes of calculating potential emissions. For example, total potential HAP emissions are greater for biomass combustion than for natural gas combustion, so in the case of total HAPs the maximum potential emissions are based on biomass combustion. In contrast, maximum potential n-hexane emissions are greater for natural gas combustion, so in the case of n-hexane the maximum potential emissions are based on natural gas combustion. Because of this conservative approach, individual HAP potential emissions will not sum to equal total HAP potential emissions.

HAP Emissions, Biomass Combustion

	lb/MMBtu	lb/hr	tpy
HCl	5.40E-03	1.46E+00	6.39E+00
Hg	1.00E-05	2.70E-03	1.18E-02
POM	1.43E-04	3.86E-02	1.69E-01
Total HAPs (biomass)	5.55E-03	1.50E+00	6.57E+00

HAP Emissions, Natural Gas Combustion

	lb/MMscf	lb/MMBtu	lb/hr	tpy
Total HAPs (natural gas)	1.89E+00	1.85E-03	4.63E-01	2.03E+00
Organic HAP Speciation				
n-hexane	1.80E+00	1.76E-03	4.41E-01	1.93E+00
formaldehyde	7.50E-02	7.35E-05	1.84E-02	8.05E-02
toluene	3.40E-03	3.33E-06	8.33E-04	3.65E-03
benzene	2.10E-03	2.06E-06	5.15E-04	2.25E-03
dichlorobenzene	1.20E-03	1.18E-06	2.94E-04	1.29E-03
naphthalene	6.10E-04	5.98E-07	1.50E-04	6.55E-04
POM Speciation				
total POM	8.82E-05	8.65E-08	2.16E-05	9.47E-05
2-methylnaphthalene	2.40E-05	2.35E-08	5.88E-06	2.58E-05
phenanthrene	1.70E-05	1.67E-08	4.17E-06	1.83E-05
7,12-dimethylbenz(a)anthracene	1.60E-05	1.57E-08	3.92E-06	1.72E-05
pyrene	5.00E-06	4.90E-09	1.23E-06	5.37E-06
benzo(b,k)fluoranthene	3.60E-06	3.53E-09	8.82E-07	3.86E-06
fluoranthene	3.00E-06	2.94E-09	7.35E-07	3.22E-06
fluorene	2.80E-06	2.75E-09	6.86E-07	3.01E-06
anthracene	2.40E-06	2.35E-09	5.88E-07	2.58E-06
acenaphthene	1.80E-06	1.76E-09	4.41E-07	1.93E-06
acenaphthylene	1.80E-06	1.76E-09	4.41E-07	1.93E-06
benz(a)anthracene	1.80E-06	1.76E-09	4.41E-07	1.93E-06
chrysene	1.80E-06	1.76E-09	4.41E-07	1.93E-06
indeno(1,2,3-cd)pyrene	1.80E-06	1.76E-09	4.41E-07	1.93E-06
3-methylchloranthene	1.80E-06	1.76E-09	4.41E-07	1.93E-06
benzo(a)pyrene	1.20E-06	1.18E-09	2.94E-07	1.29E-06
benzo(g,h,i)perylene	1.20E-06	1.18E-09	2.94E-07	1.29E-06
dibenzo(a,h)anthracene	1.20E-06	1.18E-09	2.94E-07	1.29E-06
Inorganic HAP Speciation				
nickel	2.10E-03	2.06E-06	5.15E-04	2.25E-03
chromium	1.40E-03	1.37E-06	3.43E-04	1.50E-03
cadmium	1.10E-03	1.08E-06	2.70E-04	1.18E-03
manganese	3.80E-04	3.73E-07	9.31E-05	4.08E-04
mercury	2.60E-04	2.55E-07	6.37E-05	2.79E-04
arsenic	2.00E-04	1.96E-07	4.90E-05	2.15E-04
cobalt	8.40E-05	8.24E-08	2.06E-05	9.02E-05
selenium	2.40E-05	2.35E-08	5.88E-06	2.58E-05
beryllium	1.20E-05	1.18E-08	2.94E-06	1.29E-05

REFERENCES/NOTES

1 Emission factors based on proposed BACT emission limits.

2 HAP emission factors are not available for stillage cake. Emission factors from AP-42 Section 1.8, Bagasse Combustion In Sugar Mills (Oct. 1996), were used as a surrogate except for HCl and Hg.

HIGHLANDS ETHANOL, LLC
HIGHLANDS COUNTY, FLORIDA
GAS BOILER (PEAKING STEAM DEMAND)

SOURCE DESCRIPTION

The gas boiler is fired with natural gas and will be used to provide steam to the facility processes during peak demand periods. The boiler is conservatively assumed to operate at full capacity year-round. The unit will utilize best available control technology (BACT) to minimize emissions. Specifically, the boiler will be equipped with ultra-low NOx burners to control NOx emissions. Good combustion practices will be used to minimize CO and VOC emissions. Natural gas is inherently low in sulfur and produces little PM emissions.

OPERATING PARAMETERS

Boiler

Operating Schedule	8,760	hrs/yr	
Fuels		Natural Gas	
Capacity	95	MMBtu/hr	
Natural Gas HHV	1,020	Btu/scf	from AP42
Capacity	93,137	scf/hr	
Sulfur Content	0.02	gr/scf	from FDEP
F-Factor	10,610	scf/MMBtu	from 40 CFR 60 Method 19
Exhaust Flow	29,590	acfm	
Exit Temperature	350	°F	
Exit Diameter	4	ft	
Exit Velocity	39.24	ft/s	

EMISSION CALCULATIONS

Criteria Pollutant and GHG Emission Factors for Natural Gas

Pollutant		lb/MMBtu	Emission Factor Source
PM10		0.004	BACT
PM2.5		0.004	BACT
SO2		0.0056	BACT
NOx		0.035	BACT
CO		0.037	BACT
VOC		0.0014	BACT
CO2	1	117.6	AP42, Table 1.4-2
CH4	21	0.00225	AP42, Table 1.4-2
N2O	310	0.000627	AP42, Table 1.4-2

Typical Emissions

Typical = *Boiler Capacity (95 MMBtu/hr) x Emission Factor (lb/MMBtu)*

PM10 = *95 MMBtu/hr * 0.004 lbs/MMBtu*
0.380 lbs PM/hr

PM2.5 = *95 MMBtu/hr * 0.004 lbs/MMBtu*
0.380 lbs PM/hr

SO2 = *95 MMBtu/hr * 0.0055964 lbs/MMBtu*
0.532 lbs SO2/hr

NOx = *95 MMBtu/hr * 0.035 lbs/MMBtu*
3.33 lbs NOx/hr

CO = *95 MMBtu/hr * 0.037 lbs/MMBtu*
3.52 lbs CO/hr

VOC = *95 MMBtu/hr * 0.0014 lbs/MMBtu*
0.133 lbs VOC/hr

CO2 = 95 MMBtu/hr x 117.6 lbs/MMBtu
11,176 lb CO2/hr

CH4 = 95 MMBtu/hr x 0.00225 lbs/MMBtu
0.214 lb CH4/hr

N2O = 95 MMBtu/hr x 0.000627 lbs/MMBtu
0.0596 lb N2O/hr

CO2e (total) = (11,176 lb CO2/hr x 1 lb CO2e/lb CO2) + (0.214 lb CH4/hr x 21 lb CO2e/lb CH4) + (0.0596 lb N2O/hr x 310 lb CO2e/lb N2O)
11,199 lb CO2e/hr

CO2e (non-biogenic) = (11,176 lb CO2/hr x 1 lb CO2e/lb CO2) + (0.214 lb CH4/hr x 21 lb CO2e/lb CH4) + (0.0596 lb N2O/hr x 310 lb CO2e/lb N2O)
11,199 lb CO2e/hr

Annual Emissions

*Annual = Average (lbs/hr) * 8,760 hrs/yr / 2,000 lbs/ton*

PM10 = *(0.380 lbs/hr) * (8,760 hrs/yr) / (2,000 lbs/ton)*
1.664 TPY Total PM10

PM2.5 = *(0.380 lbs/hr) * (8,760 hrs/yr) / (2,000 lbs/ton)*
1.664 TPY Filterable PM2.5

SO2 = *(0.532 lbs/hr) * (8,760 hrs/yr) / (2,000 lbs/ton)*
2.33 TPY SO2

NOx = *(3.33 lbs/hr) * (8,760 hrs/yr) / (2,000 lbs/ton)*
14.6 TPY NOx

CO = *(3.52 lbs/hr) * (8,760 hrs/yr) / (2,000 lbs/ton)*
15.4 TPY CO

VOC = *(0.133 lbs/hr) * (8,760 hrs/yr) / (2,000 lbs/ton)*
0.583 TPY VOC

*CO2e (total) = (11,199 lbs/hr) * (8,760 hrs/yr) / (2,000 lbs/ton)*
49,054 TPY CO2e

*CO2e (non-biogenic) = (11,199 lbs/hr) * (8,760 hrs/yr) / (2,000 lbs/ton)*
49,054 TPY CO2e

TOTAL CRITERIA POLLUTANT EMISSIONS SUMMARY

Pollutant	*Typical (lbs/hr)*	*Annual (TPY)*
PM10	0.380	1.664
PM2.5	0.380	1.664
SO2	0.532	2.33
NOx	3.33	14.6
CO	3.52	15.4
VOC	0.133	0.583
CO2e (total)	11,199	49,054
CO2e (non-biogenic)	11,199	49,054
total HAP	0.176	0.770

Dispersion Modeling Emissions Summary

Pollutant		*Averaging Period*	*Emissions (lb/hr)*	*Emissions (g/s)*
PM_{10}		24-Hour	0.380	0.0479
$PM_{2.5}$		24-Hour	0.380	0.0479
SO_2		1-Hour	0.532	0.0670
SO_2		3-Hour	0.532	0.0670
SO_2		24-Hour	0.532	0.0670
SO_2		Annual	0.532	0.0670
NO_2		1-Hour	3.325	0.419
NO_2		Annual	3.33	0.419
CO		1-Hour	3.52	0.443
CO		8-Hour	3.52	0.443

HIGHLANDS ETHANOL, LLC
HIGHLANDS COUNTY, FLORIDA
GAS BOILER (PEAKING STEAM DEMAND)

TOTAL SPECIATED POLLUTANT EMISSIONS SUMMARY [1]

	lb/MMscf	lb/MMBtu	lb/hr	tpy
HAP	1.89E+00	1.85E-03	1.76E-01	7.70E-01
Organic HAP Speciation				
n-hexane	1.80E+00	1.76E-03	1.68E-01	7.34E-01
formaldehyde	7.50E-02	7.35E-05	6.99E-03	3.06E-02
toluene	3.40E-03	3.33E-06	3.17E-04	1.39E-03
benzene	2.10E-03	2.06E-06	1.96E-04	8.57E-04
dichlorobenzene	1.20E-03	1.18E-06	1.12E-04	4.90E-04
naphthalene	6.10E-04	5.98E-07	5.68E-05	2.49E-04
POM Speciation				
total POM	8.82E-05	8.65E-08	8.21E-06	3.60E-05
2-methylnaphthalene	2.40E-05	2.35E-08	2.24E-06	9.79E-06
phenanthrene	1.70E-05	1.67E-08	1.58E-06	6.94E-06
7,12-dimethylbenz(a)anthracene	1.60E-05	1.57E-08	1.49E-06	6.53E-06
pyrene	5.00E-06	4.90E-09	4.66E-07	2.04E-06
benzo(b,k)fluoranthene	3.60E-06	3.53E-09	3.35E-07	1.47E-06
fluoranthene	3.00E-06	2.94E-09	2.79E-07	1.22E-06
fluorene	2.80E-06	2.75E-09	2.61E-07	1.14E-06
anthracene	2.40E-06	2.35E-09	2.24E-07	9.79E-07
acenaphthene	1.80E-06	1.76E-09	1.68E-07	7.34E-07
acenaphthylene	1.80E-06	1.76E-09	1.68E-07	7.34E-07
benz(a)anthracene	1.80E-06	1.76E-09	1.68E-07	7.34E-07
chrysene	1.80E-06	1.76E-09	1.68E-07	7.34E-07
indeno(1,2,3-cd)pyrene	1.80E-06	1.76E-09	1.68E-07	7.34E-07
3-methylchloranthene	1.80E-06	1.76E-09	1.68E-07	7.34E-07
benzo(a)pyrene	1.20E-06	1.18E-09	1.12E-07	4.90E-07
benzo(g,h,i)perylene	1.20E-06	1.18E-09	1.12E-07	4.90E-07
dibenzo(a,h)anthracene	1.20E-06	1.18E-09	1.12E-07	4.90E-07
Inorganic HAP Speciation				
nickel	2.10E-03	2.06E-06	1.96E-04	8.57E-04
chromium	1.40E-03	1.37E-06	1.30E-04	5.71E-04
cadmium	1.10E-03	1.08E-06	1.02E-04	4.49E-04
manganese	3.80E-04	3.73E-07	3.54E-05	1.55E-04
mercury	2.60E-04	2.55E-07	2.42E-05	1.06E-04
arsenic	2.00E-04	1.96E-07	1.86E-05	8.16E-05
cobalt	8.40E-05	8.24E-08	7.82E-06	3.43E-05
selenium	2.40E-05	2.35E-08	2.24E-06	9.79E-06
beryllium	1.20E-05	1.18E-08	1.12E-06	4.90E-06

REFERENCES/NOTES

1 Emission factors based on EPA AP-42, Section 1.4 *"Natural Gas Combustion"*, July 1998.

HIGHLANDS ETHANOL, LLC
HIGHLANDS COUNTY, FLORIDA
FIRE PUMP

SOURCE DESCRIPTION

The diesel pump will be used in the event of a fire. The pump will be tested weekly for approximately 1 hour or less, and will be operationally limited to less than 500 hours per year.

OPERATING PARAMETERS, EACH ENGINE

Operating Schedule	500	hrs/yr
Capacity	850	hp
	6.16	MMBtu/hr
Primary Fuel	#2 Diesel (ULSD)	
Sulfur Content	15	ppm (ULSD)

EMISSION CALCULATIONS, EACH ENGINE

Pollutant	g/kW-hr [1]	GWP	Pollutant	lb/MMBtu [2]
PM10	0.2		Acetaldehyde	0.0000252
SOx	0.00738		Acrolein	0.00000788
NOx	5.76		Benzene	0.000776
CO	3.5		Formaldehyde	0.0000789
VOC	0.64		Propylene	0.00279
CO2*	165	1	Toluene	0.000281
CH4*	0.0066	21	Xylene	0.000193
N2O*	0.00132	310		

*Emission factors for GHGs are lb/MMBtu. For CO2, EFs are from AP-42 Section 3.4. For CH4 and N2O, EFs from Part 98 Table C-2.

Average Emissions - Criteria Pollutants

*Average = Capacity (kW) * Emission Factor (g/kW-hr) * (1 lb/453.5924 g)*

*PM = 634 kW * 0.2 g/kW-hr * (1 lb/453.5924 g)*
0.279 lb PM10/hr

*SO2 = 634 kW * 0.0074 g/kW-hr * (1 lb/453.5924 g)*
0.0103 lb SO2/hr

*NOx = 634 kW * 5.76 g/kW-hr * (1 lb/453.5924 g)*
8.0 lb NOx/hr

*CO = 634 kW * 3.5 g/kW-hr * (1 lb/453.5924 g)*
4.9 lb CO/hr

*VOC = 634 kW * 0.64 g/kW-hr * (1 lb/453.5924 g)*
0.89 lb VOC/hr

CO2 = *6.16 MMBtu/hr * 165 lb/MMBtu*
1,017 lb CO2/hr

CH4 = *6.16 MMBtu/hr * 0.0066 lb/MMBtu*
0.0407 lb CH4/hr

N2O = *6.16 MMBtu/hr * 0.00132 lb/MMBtu*
0.0081 lb N2O/hr

CO2e = *(1,017 lb CO2/hr x lb CO2e/lb) + (0.0407 lb CH4/hr x lb CO2e/lb CH4) + (0.00814 lb N2O/hr x 1 lb CO2e/lb N2O)*
1,020 lb CO2e/hr

Average Emissions - Speciated Pollutants

*Average = Capacity (6.16 MMBtu/hr) * Emission Factor (lb/MMBtu)*

*Acetaldehyde = 6.16 MMBtu/hr * 0.0000252 lb/MMBtu*
0.00016 lb Acetaldehyde/hr

*Acrolein = 6.16 MMBtu/hr * 0.0000079 lb/MMBtu*
0.00005 lb Acrolein/hr

*Benzene = 6.16MMBtu/hr * 0.000776 lb/MMBtu*
0.005 lb Benzene/hr

*Formaldehyde = 6.16 MMBtu/hr * 0.0000789 lb/MMBtu*
0.0005 lb Formaldehyde/hr

*Propylene = 6.16 MMBtu/hr * 0.002790 lb/MMBtu*
0.017 lb Propylene/hr

*Toluene = 6.16 MMBtu/hr * 0.000281 lb/MMBTu*
0.0017 lb Toluene/hr

*Xylene = 6.16 MMBtu/hr * 0.000193 lb/MMBtu*
0.0012 lb Xylene/hr

Annual Emissions

*Total = Average lbs/hr * 500 hrs/yr / 2,000 lbs/ton*

*PM10 = 0.28 lbs/hr * 500 hrs/yr / 2,000 lbs/ton*
0.07 TPY PM10

*SO2 = 0.01 lbs/hr * 500 hrs/yr / 2,000 lbs/ton*
0.003 TPY SO2

*NOx = 8.05 lbs/hr * 500 hrs/yr / 2,000 lbs/ton*
2.01 TPY NOx

*CO = 4.89 lbs/hr * 500 hrs/yr / 2,000 lbs/ton*
1.22 TPY CO

*VOC = 0.89 lbs/hr * 500 hrs/yr / 2,000 lbs/ton*
0.22 TPY VOC

CO2e = *1,020 lbs/hr * 500 hrs/yr / 2,000 lbs/ton*
255 TPY CO2e

*Acetaldehyde = 0.00016 lbs/hr * 500 hrs/yr / 2,000 lbs/ton*
0.0000 TPY Acetaldehyde

*Acrolein = 0.00005 lbs/hr * 500 hrs/yr / 2,000 lbs/ton*
0.00001 TPY Acrolein

*Benzene = 0.005 lbs/hr * 500 hrs/yr / 2,000 lbs/ton*
0.001 TPY Benzene

*Formaldehyde = 0.0005 lbs/hr * 500 hrs/yr / 2,000 lbs/ton*
0.0001 TPY Formaldehyde

*Propylene = 0.0012 lbs/hr * 500 hrs/yr / 2,000 lbs/ton*
0.0003 TPY Propylene

*Toluene = 0.017 lbs/hr * 500 hrs/yr / 2,000 lbs/ton*
0.00 TPY Toluene

*Xylene = 0.0017 lbs/hr * 500 hrs/yr / 2,000 lbs/ton*
0.000 TPY Xylene

Emissions Summary - Each Engine

Pollutant	***Average (lbs./hr)***	***Annual (TPY)***
PM10	0.279	0.070
PM2.5	0.279	0.070
SOx	0.01031	0.00258
NOx	8.0	2.01
CO	4.89	1.22
Total VOC	0.89	0.224
CO2e	1,020	255
HAPs	0.0244	0.0061
Acetaldehyde	0.00016	0.000039
Acrolein	0.000049	0.000012
Benzene	0.0048	0.0012
Formaldehyde	0.00049	0.00012
Propylene	0.0012	0.00030
Toluene	0.017	0.0043
Xylene	0.0017	0.00043

REFERENCES/NOTES

1 40 CFR 60 Subpart IIII
2 Emission factor based on AP-42, Table 3.4-3: Speciated Organic Compound Emission Factors for Large Uncontrolled Stationary Diesel Engines, October 1996.

HIGHLANDS ETHANOL, LLC
HIGHLANDS COUNTY, FLORIDA
EMERGENCY GENERATORS

SOURCE DESCRIPTION

Five emergency generators will be used in the event of power supply disruptions. The engines will be tested weekly for approximately 1 hour or less, and will be operationally limited to less than 500 hours per year. Emissions listed here are per each engine.

OPERATING PARAMETERS, EACH ENGINE

Operating Schedule	500 hrs/yr		
Capacity	2,012 hp		1500 ekW
	14.59 MMBtu/hr		104.2 gal/hr
Primary Fuel	#2 Diesel (ULSD)		
Sulfur Content	15 ppm (ULSD)		

EMISSION CALCULATIONS, EACH ENGINE

Pollutant	g/kW-hr [1]	GWP	Pollutant	lb/MMBtu [2]
PM10	0.2		Acetaldehyde	0.0000252
SOx	0.00738		Acrolein	0.00000788
NOx	5.76		Benzene	0.000776
CO	3.5		Formaldehyde	0.0000789
VOC	0.64		Propylene	0.00279
CO2*	165	1	Toluene	0.000281
CH4*	0.0066	21	Xylene	0.000193
N2O*	0.00132	310		

*Emission factors for GHGs are lb/MMBtu. For CO2, EFs are from AP-42 Section 3.4. For CH4 and N2O, EFs from Part 98 Table C-2.

Average Emissions - Criteria Pollutants

*Average = Capacity (kW) * Emission Factor (g/kW-hr) * (1 lb/453.5924 g)*

*PM = 1,500 kW * 0.2 g/kW-hr * (1 lb/453.5924 g)*
0.661 lb PM10/hr

*SO2 = 1,500 kW * 0.0074 g/kW-hr * (1 lb/453.5924 g)*
0.0244 lb SO2/hr

*NOx = 1,500 kW * 5.76 g/kW-hr * (1 lb/453.5924 g)*
19.0 lb NOx/hr

*CO = 1,500 kW * 3.5 g/kW-hr * (1 lb/453.5924 g)*
11.6 lb CO/hr

*VOC = 1,500 kW * 0.64 g/kW-hr * (1 lb/453.5924 g)*
2.12 lb VOC/hr

CO2 = *14.59 MMBtu/hr * 165 lb/MMBtu*
2,407 lb CO2/hr

CH4 = *14.59 MMBtu/hr * 0.0066 lb/MMBtu*
0.0963 lb CH4/hr

N2O = *14.59 MMBtu/hr * 0.00132 lb/MMBtu*
0.0193 lb N2O/hr

CO2e = *(2,407 lb CO2/hr x lb CO2e/lb) + (0.0963 lb CH4/hr x lb CO2e/lb CH4)*
+ (0.01925 lb N2O/hr x 1 lb CO2e/lb N2O)
2,415 lb CO2e/hr

Average Emissions - Speciated Pollutants

*Average = Capacity (14.59 MMBtu/hr) * Emission Factor (lb/MMBtu)*

*Acetaldehyde = 14.59 MMBtu/hr * 0.0000252 lb/MMBtu*
0.00037 lb Acetaldehyde/hr

*Acrolein = 14.59 MMBtu/hr * 0.0000079 lb/MMBtu*
0.00011 lb Acrolein/hr

*Benzene = 14.59MMBtu/hr * 0.000776 lb/MMBtu*
0.011 lb Benzene/hr

*Formaldehyde = 14.59 MMBtu/hr * 0.0000789 lb/MMBtu*
0.0012 lb Formaldehyde/hr

*Propylene = 14.59 MMBtu/hr * 0.002790 lb/MMBtu*
0.041 lb Propylene/hr

*Toluene = 14.59 MMBtu/hr * 0.000281 lb/MMBTu*
0.0041 lb Toluene/hr

*Xylene = 14.59 MMBtu/hr * 0.000193 lb/MMBtu*
0.0028 lb Xylene/hr

Annual Emissions

*Total = Average lbs/hr * 500 hrs/yr / 2,000 lbs/ton*

*PM10 = 0.66 lbs/hr * 500 hrs/yr / 2,000 lbs/ton*
0.17 TPY PM10

*SO2 = 0.02 lbs/hr * 500 hrs/yr / 2,000 lbs/ton*
0.006 TPY SO2

*NOx = 19.05 lbs/hr * 500 hrs/yr / 2,000 lbs/ton*
4.76 TPY NOx

*CO = 11.57 lbs/hr * 500 hrs/yr / 2,000 lbs/ton*
2.89 TPY CO

*VOC = 2.12 lbs/hr * 500 hrs/yr / 2,000 lbs/ton*
0.53 TPY VOC

CO2e = *2,415 lbs/hr * 500 hrs/yr / 2,000 lbs/ton*
604 TPY CO2e

*Acetaldehyde = 0.00037 lbs/hr * 500 hrs/yr / 2,000 lbs/ton*
0.0001 TPY Acetaldehyde

*Acrolein = 0.00011 lbs/hr * 500 hrs/yr / 2,000 lbs/ton*
0.00003 TPY Acrolein

*Benzene = 0.011 lbs/hr * 500 hrs/yr / 2,000 lbs/ton*
0.003 TPY Benzene

*Formaldehyde = 0.0012 lbs/hr * 500 hrs/yr / 2,000 lbs/ton*
0.0003 TPY Formaldehyde

*Propylene = 0.0028 lbs/hr * 500 hrs/yr / 2,000 lbs/ton*
0.0007 TPY Propylene

*Toluene = 0.041 lbs/hr * 500 hrs/yr / 2,000 lbs/ton*
0.01 TPY Toluene

*Xylene = 0.0041 lbs/hr * 500 hrs/yr / 2,000 lbs/ton*
0.001 TPY Xylene

Emissions Summary - Each Engine

Pollutant	***Average (lbs./hr)***	***Annual (TPY)***
PM10	0.661	0.165
PM2.5	0.661	0.165
SOx	0.02440	0.00610
NOx	19.0	4.76
CO	11.57	2.89
Total VOC	2.12	0.529
CO2e	2,415	604
HAPs	0.0577	0.0144
Acetaldehyde	0.00037	0.000092
Acrolein	0.000115	0.000029
Benzene	0.0113	0.0028
Formaldehyde	0.00115	0.00029
Propylene	0.0028	0.00070
Toluene	0.041	0.0102
Xylene	0.0041	0.00102

REFERENCES/NOTES

1 40 CFR 60 Subpart IIII
2 Emission factor based on AP-42, Table 3.4-3: Speciated Organic Compound Emission Factors for Large Uncontrolled Stationary Diesel Engines, October 1996.

HIGHLANDS ETHANOL, LLC
HIGHLANDS COUNTY, FLORIDA
STILLAGE LOADOUT (FUGITIVE VOC)

SOURCE DESCRIPTION

Stillage is removed from the beer stripper distillation column, centrifuged to remove some of the water fraction, and conveyed to the biomass boiler. The stillage will not be dried. Stillage will be generated at a rate of 11 dry tons per hour and will consist primarily of lignin fibers and secondarily of unhydrolyzed cellulose fibers with a moisture content between 50 and 60 percent. Emissions will occur from the conveyor and the centrifuges used for dewatering. Based on the consistency and moisture content of the material, PM emissions are expected to be negligible. VOC emissions will occur from the evaporation of organics dissolved in the water fraction and escaping the conveyor as fugitive emissions.

OPERATING PARAMETERS

Operating Schedule	8,760	hrs/yr
Ethanol Production	39,420,000	gal/yr

EMISSION CALCULATIONS [1]

VOC Emission Factor	0.0004262	lb/gal

VOC Emissions

*Average Emissions = VOC Emission Factor (0.00043 lb/gal) * Ethanol Production (39,420,000 gal/yr) / Operating Hours (8,760 hrs/yr)*

Average VOC Emission Rate	1.918	lbs/hr

*Annual Emissions = Average VOC Emission Rate (1.92 lbs/hr) * 8,760 hrs/yr / 2,000 lbs/ton*

Annual VOC Emission Rate	8.40	tons/yr

Emissions Speciation [2]

Pollutant	CAS No.	Percent	HAP
Acetic Acid	64-19-7	66.5%	No
Hydroxymethylfurfural	67-47-0	16.9%	No
Ethanol	64-17-5	12.4%	No
Furfural	98-01-1	4.2%	No

Speciated Emissions

Pollutant	Average (lb/hr)	Annual (tpy)
Acetic Acid	1.275	5.586
Hydroxymethylfurfural	0.324	1.420
Ethanol	0.238	1.042
Furfural	0.081	0.353

Emissions Summary

Pollutant	***Average (lbs./hr)***	***Annual (TPY)***
Total VOC	1.9	8.4
Acetic Acid	1.3	5.6
Hydroxymethylfurfural	0.3	1.4
Ethanol	0.2	1.0
Furfural	0.1	0.4

REFERENCES/NOTES

1 Emission factor based on the procedure used for the permitting of the Pacific Ethanol Facility located in Madera, California. Three emission calculation procedures were identified and the one that resulted in the greatest VOC emission rate was selected. The emission factor was then doubled for an additional margin of safety. See Initial Study/Environmental Checklist for the Pacific Ethanol Facility, San Joaquin Valley Unified Air Pollution Control District, January 29, 2004. AMEC in turn tripled the resulting emissions factor to provide for an additional margin of safety.

2 ASPEN modeling of the water fraction of the stillage cake shows constituents that are consistent in properties with those identified in the Pacific Ethanol analysis. The speciation shown is based on the ASPEN modeling and shows only those components that EPA's WATER9 model shows to be volatile.

HIGHLANDS ETHANOL, LLC
HIGHLANDS COUNTY, FLORIDA
FUGITIVE VOC EQUIPMENT LEAKS

SOURCE DESCRIPTION

Equipment components in VOC service are subject to 40 CFR Part 60 Subpart VV; therefore components are monitored monthly. Control effectiveness is allowed for components subject to an LDAR program.

OPERATING PARAMETERS

Operating Schedule 8,760 hrs/yr

EMISSION CALCULATIONS [1]

*Average (Lbs/hr) = Component Count x Emission Factor (lb/hr/source) * (1 - Control Effectiveness/100)*

*Annual (TPY) = Average (lbs VOC/hr) * 8,760 hrs/yr / 2,000 lbs/ton*

Component Type	Service	Component Count	Emission Factors (kg/hr/source) [1]	Weighted Average VOC Content [2]	Subpart VV Control Effectiveness [3]	Emissions		
						Avg (lbs/hr)	Max (lbs/hr)	Tons/Yr
Valves	Gas/Vapor	50	0.00597	100%	87%	8.56E-02	1.03E-01	3.75E-01
Valves	Light Liquid	400	0.00403	96%	84%	5.46E-01	6.55E-01	2.39E+00
Valves	Heavy Liquid	200	0.00023	5%	0%	5.07E-03	6.08E-03	2.22E-02
Sealless Valves	Light Liquid	400	4.90E-07	96%	84%	6.64E-05	7.96E-05	2.91E-04
Sealless Valves	Heavy Liquid	200	0	5%	0%	0.00E+00	0.00E+00	0.00E+00
Pump Seals	Light Liquid	0	0.0199	96%	69%	0.00E+00	0.00E+00	0.00E+00
Pump Seals	Heavy Liquid	0	0.00862	5%	0%	0.00E+00	0.00E+00	0.00E+00
Pump Seals, Dual Mech.	Light Liquid	100	7.50E-06	96%	69%	4.92E-04	5.90E-04	2.16E-03
Pump Seals, Dual Mech.	Heavy Liquid	20	0	5%	0%	0.00E+00	0.00E+00	0.00E+00
Agitator Seals	Light Liquid	20	0.0199	96%	69%	2.61E-01	3.13E-01	1.14E+00
Agitator Seals	Heavy Liquid	20	0.00862	5%	0%	1.90E-02	2.28E-02	8.32E-02
Compressor Seals	Gas/Vapor	0	0.228	100%	0%	0.00E+00	0.00E+00	0.00E+00
Pressure Relief Valves	Gas/Vapor	0	0.104	100%	0%	0.00E+00	0.00E+00	0.00E+00
Connectors	All	2500	0.00183	30%	0%	3.03E+00	3.63E+00	1.33E+01
Open-Ended Lines	All	120	0.0017	30%	0%	1.35E-01	1.62E-01	5.91E-01
Sampling Connections	All	40	0.015	30%	0%	3.97E-01	4.76E-01	1.74E+00
					TOTAL	**4.5**	**5.4**	**19.6**

Emissions Summary

Pollutant	*Average (lbs/hr)*	*Annual (TPY)*
VOC	4.5	19.6
HAP [4]	0.22	0.98

REFERENCES/NOTES:

1 Table 2-1, SOCMI Average Emission Factors; or Table 2-11, Default-Zero Values: SOCMI Process Units; or Table 5-1, Summary of Equipment Modifications; Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017, November 1995.

2 For components in liquid service, approximately 75% are associated with liquids containing less than 5% VOC, 20% are associated with liquids containing less than 95% VOC, and 5% are associated with liquids containing greater than 95% VOC. The resulting weighted average VOC content is approximately 30%. For components in light liquid service, approximately 80% are associated with liquids containing less than 95% VOC, and 20% are associated with liquids containing greater than 95% VOC. The resulting weighted average VOC content is approximately 96%.

3 Table 5-2, Control Effectiveness for an LDAR Program at a SOCMI Process Unit, Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017, November 1995.

4 HAP emissions are conservatively assumed to represent 5% of the VOC emissions, and are conservatively assigned to acetaldehyde.

HIGHLANDS ETHANOL, LLC
HIGHLANDS COUNTY, FLORIDA
VEHICLE FUGITIVES (PAVED ROADS)

SOURCE DESCRIPTION

Approximately 60 trucks per day will be used to deliver feedstock to the feedstock hopper, and an additional 127 vehicles per day will drive on the plant roads. All roads will be paved with asphalt.

OPERATING PARAMETERS

Operating Schedule 8,760 hr/yr

Vehicle Traffic	Vehicles/Day	Miles/Vehicle	VMT/Day	VMT/Year
Feedstock Delivery	60	0.17	10.23	3,733
Employee Vehicles	60	0.73	43.78	15,979
Product Tankers	21	0.66	13.93	5,084
Denaturant Tankers	1	0.66	0.66	242
Fuel Delivery Trucks	2	1.24	2.47	903
Chemical Delivery Trucks	9	1.10	9.87	3,604
Ash Disposal Trucks	2	1.24	2.47	903
Process Waste Trucks	20	1.10	21.94	8,009
Vendors/Deliveries	5	1.10	5.49	2,002
Miscellaneous	7	1.10	7.68	2,803
TOTAL			**118.53**	**43,264**

EMISSION CALCULATIONS [1]

$$E = k\,(sL)^{0.91} * (W)^{1.02}$$

$$E_{est} = E\ (lbs/VMT) * [1-(P/4N)]$$

where:

E = particulate emission factor (lb/VMT)

	PM	PM10	PM2.5	
k =	0.011	0.0022	0.00054	particle size multiplier (Table 13.2.1-1)
sL =	0.6	0.6	0.6	road surface silt loading (g/m2, Table 13.2.1-3)
W =	15	15	15	avg weight of the vehicles traveling the road (tons)
P =	120	120	120	Days rainfall > 0.01" (Figure 13.2.1-2)
N =	365	365	365	days in averaging period

Emission Factor

*E = 0.011 * (0.6)^0.91 * (15)^1.02*

0.11 lbs PM/VMT

*E = 0.0022 * (0.6)^0.91 * (15)^1.02*

0.022 lbs PM10/VMT

*E = 0.00054 * (0.6)^0.91 * (15)^1.02*

0.003 lbs PM2.5/VMT

Adjusted for Rainfall

E_{est} = *0.11 lbs/VMT * {1-[120/(4*365)]}*

0.11 lbs PM/VMT

E_{est} = *0.02 lbs/VMT * {1-[120/(4*365)]}*

0.020 lbs PM10/VMT

E_{est} = *0.00 lbs/VMT * {1-[120/(4*365)]}*

0.003 lbs PM2.5/VMT

Emission Calculations

*Average PM (Lbs/Hr) = 0.11 lbs PM/VMT * 43,264 VMT/yr / 8,760 hrs/yr*

0.5 lb/hr PM

*Annual PM (TPY) = Avg (lbs/hr) * 9 hrs/yr / 2,000 lbs/ton*

2.3 tpy PM

*Average PM10 (Lbs/Hr) = 0.020 lbs PM10/VMT * 43,264 VMT/yr / 8,760 hrs/yr*

0.10 lb/hr PM10

*Annual PM10 (TPY) = Avg (lbs/hr) * 8,760 hrs/yr / 2,000 lbs/ton*

0.43 tpy PM10

*Average PM2.5 (Lbs/Hr) = 0.0026 lbs PM10/VMT * 43,264 VMT/yr / 8,760 hrs/yr*

0.013 lb/hr PM2.5

*Annual PM2.5 (TPY) = Avg (lbs/hr) * 8,760 hrs/yr / 2,000 lbs/ton*

0.057 tpy PM2.5

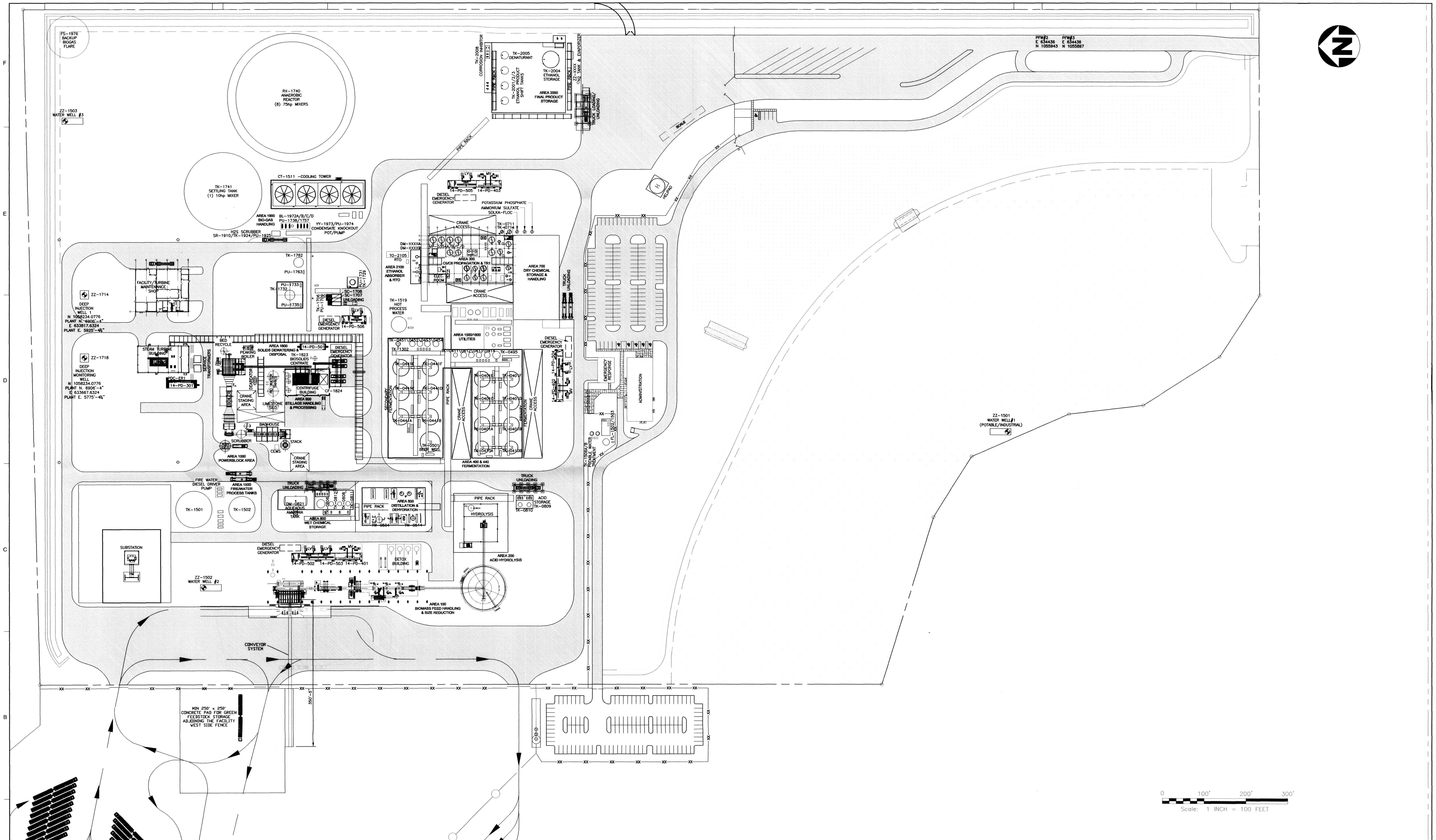
Emissions Summary

Pollutant	***Average (lbs/hr)***	***Annual (TPY)***
PM	0.5	2.3
PM10	0.1	0.4
PM2.5	0.01	0.06

REFERENCES/NOTES:

1 EPA, AP-42, Section 13.2.1, Paved Roads, January 2011.

APPENDIX C
Site Plan



REV	DDMMMYY	REVISION / ISSUE DESCRIPTION	BY	CHK	APP	CLIENT APP
A	01AUG2012	ISSUED FOR AIR PERMIT APPLICATION	GH	GB	BB	

STAMP/SEAL

PROPRIETARY INFORMATION: THIS DRAWING IS THE PROPERTY OF HIGHLANDS ETHANOL, LLC AND IS NOT TO BE LOANED OR REPRODUCED IN ANY WAY WITHOUT THE PERMISSION OF HIGHLANDS ETHANOL, LLC.

CH2MHILL.

FLORIDA REGISTERED ENGINEERING FIRM EB0000072
FLORIDA REGISTERED ARCHITECTURAL FIRM AAC001992
TEXAS REGISTERED ENGINEERING FIRM F-3699

bp

	NAME	DDMMMYY
DESIGNED BY	GAH	02/28/2012
DRAWN BY	GAH	02/28/2012
CHECKED BY	GRB	07/02/2012
APPROVED BY	WLB	07/02/2012

SUBJECT
HIGHLANDS ETHANOL, LLC
PLOT PLAN - PERMITTING

PROJECT NO.	SCALE
418587	1"=100'

DRAWING NO.	REV.
SK-P-0020	A

amec

APPENDIX D
USEPA Applicability Determinations for NSPS Subparts NNN and RRR

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

MAR 26 2009

Mr. Joseph Kahn, Director
Division of Air Resources Management
Florida Department of Environmental Protection
Mail Station 5500
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Mr. Kahn:

We have received a request for an applicability determination from Highlands Ethanol, LLC, an affiliate of Verenium Biofuels Corporation, concerning a new fuel-grade cellulosic ethanol production facility to be constructed in Highlands County, Florida. The company requests a determination concerning the applicability of New Source Performance Standards (NSPS) Subpart NNN – "Standards of Performance for Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations" and Subpart RRR – "Standards of Performance for VOC Emissions From SOCMI Reactor Processes." Highlands Ethanol will produce fuel-grade ethanol by the use of fermentation (biological synthesis). We have reviewed the Highlands Ethanol request and have determined the facility will not be subject to Subparts NNN and RRR.

NSPS Subpart NNN applies to affected facilities described in Section 60.660(b) that are part of a process unit producing any of the listed chemicals in Section 60.667 as a product, co-product, by-product, or intermediate. NSPS Subpart RRR applies to affected facilities described in Section 60.700(b) that are part of a process unit producing any of the listed chemicals in Section 60.707 as a product, co-product, by-product, or intermediate. Subparts NNN and RRR both identify ethanol as a listed chemical. However, background information documents created during the development of Subparts NNN and RRR indicate the production of ethanol by biological synthesis is outside the scope of both standards. As stated on page 8-23 of the background information document for the proposed Subpart NNN standard (EPA-450/3-83-005a; December 1983) - "The scope of the distillation NSPS does not include polymers, coal tar distillation products, chemicals extracted from natural resources, or chemicals totally produced by biological synthesis." Also, the background information document for the proposed Subpart RRR standard (EPA-450/3-90-016a; June 1990) indicates on page 3-2 that the list of chemicals included in the scope of the standard does not include polymers or chemicals produced exclusively by biological synthesis.

The U.S. Environmental Protection Agency (EPA) has previously indicated the applicability of Subparts NNN and RRR should be determined on a case-by-case basis for facilities producing ethanol by the use of a biological fermentation process. Based on a review of previous EPA determinations and background documents, we have determined the production of fuel-grade ethanol by fermentation at the Highlands Ethanol facility will not be subject to NSPS Subparts NNN and RRR.

If there are any questions regarding this determination, please contact Mr. Keith Goff of the EPA Region 4 staff at (404) 562-9137.

Sincerely,

Carol L. Kemker
Acting Director
Air, Pesticides, and Toxics
Management Division

cc: Al Linero, Florida Department of
Environmental Protection

Jeff Harrington, AMEC Earth & Environmental

APPENDIX E
USEPA's RACT/BACT/LAER Clearinghouse Data

Table E-1

Recent BACT/Permit Decisions - VOC from Fermentation

RBLC ID	Permit No.	Date	State	Owner/Facility	Process	Control Technology	Control Efficiency	Basis	Source
IA-0092	06-A-571P - 06-A-590P	4/19/2007	IA	Southwest Iowa Renewable Energy	Fermentation	Wet Scrubber	95%	BACT-PSD	RBLC Clearinghouse
IA-0082	03-A-600P-S2	4/19/2006	IA	Golden Grain Energy	Fermentation	Water Scrubber	95%	BACT-PSD	RBLC Clearinghouse
MN-0062	14300014-005	12/22/2005	MN	Heartland Corn Products	Fermentation	Absorption Column	95%	BACT-PSD	RBLC Clearinghouse
NA	F-06-033	8/31/2006	KY	Bluegrass Bioenergy, LLC	Degasser, Beer Well, Fermenters	CO2 Scrubber	95%	Conditional Major Permit	State Permit Files
NA	04300041-009	5/9/2008	MN	Corn Plus	Fermentation and Beer Well	Scrubber	95%	BACT-PSD	State Permit Files
IA-0089	07-A-955P - 07-A-982P	8/8/2007	IA	Homeland Energy Solutions LLC, PN 06-672	Fermenters/Beerwell	Scrubber	97%	BACT-PSD	RBLC Clearinghouse
ND-0020	4004	8/4/2004	ND	Red Tail Energy, LLC - Richardton Plant	Fermentation	Wet Scrubber	97%	BACT-PSD	RBLC Clearinghouse
IA-0095	Project 08-126	9/19/2008	IA	Tate & Lyle Ingredients Americas, Inc.	Ethanol Fermentation Area	CO2 Scrubber, Distillation Scrubber & RTO	98%	BACT-PSD	RBLC Clearinghouse
PA-0257	17-313-001	5/7/2007	PA	Sunnyside Ethanol, LLC	Fermentation	Packed Bed Counterflow Scrubber	98%	Other	RBLC Clearinghouse
IL-0102	5010062	11/1/2005	IL	Aventine Renewable Energy	Fermentation	CO2 Scrubber, Purge Scrubber	98%	BACT-PSD	RBLC Clearinghouse
IA-0088	57-01-080	6/29/2007	IA	Archer Daniels Midland ADM Corn Processing - Cedar Rapids	Fermentation Distillation and Dehydration	Scrubber and RTO	98%	BACT-PSD	RBLC Clearinghouse
OH-0303	01-01306	8/10/2006	OH	Asaliance Biofuels, LLC; Asa Bloominburg, LLC	Fermenting Units	CO2 Wet Scrubber; Leak Detection & Repair	98.5%	State BAT; NSPS VV	RBLC Clearinghouse
WI-0204	03-DCF-048	8/14/2003	WI	United Wisconsin Grain Producers - Fuel Grade Ethanol Plant	Fermentation Process	Wet Scrubber Packed Tower	98.7%	Other	RBLC Clearinghouse
NE-0046	CP06-0048	9/27/2007	NE	Aventine Renewable Energy - Aurora West, LLC	Fermentation Operations	CO2 Scrubber	99%	BACT-PSD	RBLC Clearinghouse
FL-0322	0510032-001-AC	12/23/2010	FL	Southeast Renewable Fuels (SRF), LLC	Fermentation	Wet Scrubber	98%	BACT-PSD	RBLC Clearinghouse
NA	0550063-001-AC	9/23/2011	FL	Highlands EnviroFuels (HEF), LLC	Fermentation	Wet Scrubber	98%	BACT-PSD	State Permit Files
NA	0610096-001-AC		FL	INEOS New Planet BioEnergy	Fermentation	Wet Scrubber	95%	Minor Construction	State Permit Files
NA	2869-205-0047-S-02-0	12/28/2007	GA	Southwest Georgia Ethanol, LLC	Fermentation	Wet Scrubber	Not Specified	PSD Avoidance	State Permit Files
NA	2869-305-0037-E-01-0	7/29/2009	GA	East Coast Ethanol, LLC	Fermentation	Scrubber	Not Specified	PSD Avoidance	State Permit Files
NA	0240-00092	5/1/2006	MS	Southern Ethanol Company, LLC - Rosedale	Fermentation	Scrubber	Not Specified	Minor Construction	State Permit Files
NA	1840-00078	9/22/2006	MS	Southern Ethanol Company, LLC - Amory	Fermentation	Scrubber	Not Specified	Minor Construction	State Permit Files
NA	1560-00075	8/3/2004	MS	Delta Ethanol, LLC	Fermentation	Scrubber	Not Specified	Minor Construction	State Permit Files
NA	0571321-001-AC	4/5/2006	FL	United States EnviroFuels, LLC - Port Sutton Ethanol Facility	Fermentation Process	CO2 Scrubber	Not Specified	Minor Construction	State Permit Files
NA	0810213-001-AC	11/15/2005	FL	United States EnviroFuels, LLC -Port Manatee Ethanol Facility	Fermentation Process	CO2 Scrubber	Not Specified	Minor Construction	State Permit Files
NA	S-06-021	2/27/2006	KY	Commonwealth Agri-Energy, LLC	Fermentation	CO2 Scrubber	Not Specified	Minor Construction/Operating	State Permit Files
NA	F-07-047	11/27/2007	KY	The Four Rivers BioEnergy Company, Inc.	Fermenting Operations	Scrubber & Regenerative Thermal Oxidizer	Not Specified	Conditional Major/Synthetic Minor	State Permit Files
NA	F-07-025	9/6/2007	KY	Kentucky 5 Star Energy, LLC	Fermentation	CO2 Scrubber	Not Specified	Conditional Major/Synthetic Minor	State Permit Files
NA	1050145-003-AF	3/8/2007	FL	Bartow Ethanol of Florida L.C.	Fermentation Unit	No Control	No Control	FESOP	State Permit Files
NA	V-07-024 R1	10/31/2007	KY	Constellation Spirits Inc.	Fermentation	No Control	No Control	Conditional Major Operating	State Permit Files
NA	V-0-7-0038	10/15/2007	KY	Buffalo Trace Distillery Inc.	Fermentation (includes distilling process)	No Control	No Control	Title V	State Permit Files
NA	F-06-037	12/22/2006	KY	Four Roses Distillery, LLC	Fermentation, Distillation, Beer Wells, Spent Grain Processing	No Control	No Control	Conditional Major/FESOP	State Permit Files

Table E-2									
Recent BACT/Permit Decisions - VOC from Distillation									
RBLC ID	Permit No.	Date	State	Owner/Facility	Process	Control Technology	Control Efficiency	Basis	Source
MN-0062	14300014-005	12/22/2005	MN	Heartland Corn Products	Distillation	Scrubber (Absorption column)	95%	BACT-PSD	RBLC Clearinghouse
NA	0430041-009	5/9/2008	MN	Corn Plus	Distillation Process	Scrubber	95%	BACT-PSD	State Permit Files
IA-0092	06-A-571P - 06-A-590P	4/19/2007	IA	Southwest Iowa Renewable Energy	DDGS Dryers & Distillation	Thermal Oxidizer	98%	BACT-PSD; NSPS	RBLC Clearinghouse
IA-0088	57-01-080	6/29/2007	IA	Archer Daniels Midland ADM Corn Processing - Cedar Rapids	Fermentation Distillation and Dehydration	Scrubber and RTO	98%	BACT-PSD	RBLC Clearinghouse
NE-0046	CP06-0048	9/27/2007	NE	Aventine Renewable Energy - Aurora West, LLC	Pre-Fermentation, Distillation and DGS Drying Operations	Regenerative Thermal Oxidizer	99%	BACT-PSD	RBLC Clearinghouse
FL-0322	0510032-001-AC	12/23/2010	FL	Southeast Renewable Fuels (SRF), LLC	Fermentation	Wet Scrubber	98%	BACT-PSD	RBLC Clearinghouse
NA	0550063-001-AC	9/23/2011	FL	Highlands EnviroFuels (HEF), LLC	Fermentation	Wet Scrubber	98%	BACT-PSD	State Permit Files
NA	0610096-001-AC		FL	INEOS New Planet BioEnergy	Fermentation	Wet Scrubber	95%	Minor Construction	State Permit Files
NA	0240-00092	5/1/2006	MS	Southern Ethanol Company, LLC - Rosedale	Distillation	Scrubber	Not Specified	Minor Construction	State Permit Files
NA	1840-00078	9/22/2006	MS	Southern Ethanol Company, LLC - Amory	Distillation	Scrubber	Not Specified	Minor Construction	State Permit Files
NA	1560-00075	8/3/2004	MS	Delta Ethanol, LLC	Distillation	Scrubber	Not Specified	Minor Construction	State Permit Files
NA	0571321-001-AC	4/5/2006	FL	United States EnviroFuels, LLC - Port Sutton Ethanol Facility	Distillation Process	Scrubber	Not Specified	Minor Construction	State Permit Files
NA	0810213-001-AC	11/15/2005	FL	United States EnviroFuels, LLC -Port Manatee Ethanol Facility	Distillation Process	Scrubber	Not Specified	Minor Construction	State Permit Files
NA	S-06-021	2/27/2006	KY	Commonwealth Agri-Energy, LLC	Distillation	Process Blower	Not Specified	Minor Construction/Operating	State Permit Files
NA	F-07-025	9/6/2007	KY	Kentucky 5 Star Energy, LLC	Distillation	Vent Gas Scrubber	Not Specified	Conditional Major/Synthetic Minor	State Permit Files
NA	1050145-003-AF	3/8/2007	FL	Bartow Ethanol of Florida L.C.	Distillation	No Control	No Control	FESOP	State Permit Files
NA	V-0-7-0038	10/15/2007	KY	Buffalo Trace Distillery Inc.	Fermentation (includes distilling process)	No Control	No Control	Title V	State Permit Files
NA	F-06-037	12/22/2006	KY	Four Roses Distillery, LLC	Fermentation, Distillation, Beer Wells, Spent Grain Processing	No Control	No Control	Conditional Major/FESOP	State Permit Files

Table E-3

Recent BACT/Permit Decisions - VOC from Storage Tanks

RBLC ID	Permit No.	Date	State	Owner/Facility	Process	Control Technology	Control Efficiency	Basis	Source
PA-0257	17-313-001	5/7/2007	PA	Sunnyside Ethanol, LLC	Storage Tanks	Floating Roof Tanks	Not Specified	Other	RBLC Clearinghouse
NA	2869-205-0047-S-02-0	12/28/2007	GA	Southwest Georgia Ethanol, LLC	Storage Tanks	Internal Floating Roof	Not Specified	PSD Avoidance	State Permit Files
NA	0240-00092	5/1/2006	MS	Southern Ethanol Company, LLC - Rosedale	Storage Tanks	Internal Floating Roof	Not Specified	Minor Construction	State Permit Files
NA	1840-00078	9/22/2006	MS	Southern Ethanol Company, LLC - Amory	Storage Tanks	Internal Floating Roof	Not Specified	Minor Construction	State Permit Files
NA	1560-00075	8/3/2004	MS	Delta Ethanol, LLC	Storage Tanks	Internal Floating Roof	Not Specified	Minor Construction	State Permit Files
NA	707-0022-X001	9/18/2007	AL	*Dixie Biodiesel, LLC*	*Storage Tanks*	*Submerged Fill Pipe*	*Not Specified*	*Minor Construction*	*State Permit Files*
NA	708-0029-X001, X002, X003	11/9/2007	AL	Athens Biodiesel, LLC	Storage Tanks	Submerged Fill Pipe	Not Specified	Minor Construction	State Permit Files
NA	413-0107-X001, X002	2/20/2008	AL	Alabama Biodiesel Corporation	Storage Tanks	Submerged Fill Pipe, vented to condensers	Not Specified	Synthetic Minor Operating	State Permit Files
NA	503-077-X017 - X023	?	AL	Dunhill Entities, L.P.(loading terminal for biodiesel, gasoline, ethanol)	Storage Tanks	Internal Floating Roofs	Not Specified	Minor Construction	State Permit Files
NA	0571321-001-AC	4/5/2006	FL	United States EnviroFuels, LLC - Port Sutton Ethanol Facility	Storage Tanks	Submerged Fill, Internal Floating Roof	Not Specified	Minor Construction	State Permit Files
NA	0810213-001-AC	11/15/2005	FL	United States EnviroFuels, LLC -Port Manatee Ethanol Facility	Storage Tanks	Submerged Fill	Not Specified	Minor Construction	State Permit Files
NA	1310023-005-AC	1/31/2008	FL	*Murphy Oil USA, Inc.*	*Ethanol Storage*	*Internal Floating Roof*	*Not Specified*	*Minor Construction*	*State Permit Files*
NA	F-06-033	8/31/2006	KY	Bluegrass Bioenergy, LLC	Storage Tanks	Internal Floating Roof	Not Specified	Conditional Major Permit	State Permit Files
NA	S-06-021	2/27/2006	KY	Commonwealth Agri-Energy, LLC	Storage Tanks	Internal Floating Roof	Not Specified	Minor Construction/Operating	State Permit Files
NA	S-07-037-R1	6/4/2007	KY	Countrymark Cooperative, LLP	Storage Tanks	Internal Floating Roof	Not Specified	Minor Source Operating	State Permit Files
NA	F-07-047	11/27/2007	KY	The Four Rivers BioEnergy Company, Inc.	Storage Tanks	Internal Floating Roof	Not Specified	Conditional Major/Synthetic Minor	State Permit Files
NA	F-07-025	9/6/2007	KY	Kentucky 5 Star Energy, LLC	Tanks	Internal Floating Roof	Not Specified	Conditional Major/Synthetic Minor	State Permit Files
NA	0430041-009	5/9/2008	MN	Corn Plus	Floating Roof Tanks	Internal Floating Roof	Not Specified	BACT-PSD	State Permit Files
OH-0303	01-01306	8/10/2006	OH	Asaliance Biofuels, LLC; Asa Bloominburg, LLC	Ethanol Storage Tanks	No Control	No Control	State BAT; NSPS	RBLC Clearinghouse
NA	0380-00055	7/31/2006	MS	Tri States Petroleum Products LLC	Ethanol, Biodiesel, and Glycerine Storage Tanks	No Control	No Control	Minor Construction	State Permit Files
NA	1050145-003-AF	3/8/2007	FL	Bartow Ethanol of Florida L.C.	Process and Storage Tanks	No Control	No Control	FESOP	State Permit Files
NA	F-03-024	12/22/2003	KY	*Heaven Hill Distilleries, Inc.*	*Outside Ethanol Storage Tanks*	*No Control*	*No Control*	*Conditional Major Operating*	*State Permit Files*

Table E-4									
Recent BACT/Permit Decisions - VOC from Product Loadout									
RBLC ID	**Permit No.**	**Date**	**State**	**Owner/Facility**	**Process**	**Control Technology**	**Control Efficiency**	**Basis**	**Source**
NA	F-06-033	8/31/2006	KY	Bluegrass Bioenergy, LLC	Truck and Rail Loadout	Flare	97%	Conditional Major Permit	State Permit Files
IA-0095	Project 08-126	9/19/2008	IA	Tate & Lyle Ingredients Americas, Inc.	Ethanol Truck Loadout	Flare	98%	BACT-PSD	RBLC Clearinghouse
IA-0095	Project 08-126	9/19/2008	IA	Tate & Lyle Ingredients Americas, Inc.	Ethanol Rail Loadout	Flare	98%	BACT-PSD	RBLC Clearinghouse
IA-0089	07-A-955P - 07-A-982P	8/8/2007	IA	Homeland Energy Solutions LLC, PN 06-672	Product Loadout	Flare	98%	BACT-PSD	RBLC Clearinghouse
IA-0088	57-01-080	6/29/2007	IA	Archer Daniels Midland ADM Corn Processing - Cedar Rapids	Alcohol Rail Loadout	Flare	98%	BACT-PSD	RBLC Clearinghouse
PA-0257	17-313-001	5/7/2007	PA	Sunnyside Ethanol, LLC	Ethanol Loadout	Flare	98%	Other	RBLC Clearinghouse
IA-0092	06-A-571P - 06-A-590P	4/19/2007	IA	Southwest Iowa Renewable Energy	Ethanol Loadout	Flare	98%	BACT-PSD; NSPS VV	RBLC Clearinghouse
NA	S-07-037-R1	6/4/2007	KY	Countrymark Cooperative, LLP	Loading Rack	Flare	98%	Minor Source Operating	State Permit Files
IA-0082	03-A-600P-S2	4/19/2006	IA	Golden Grain Energy	Ethanol Loadout	Flare	99%	BACT-PSD; NSPS	RBLC Clearinghouse
FL-0322	0510032-001-AC	12/23/2010	FL	Southeast Renewable Fuels (SRF), LLC	Ethanol Loadout	Flare	99%	BACT-PSD	RBLC Clearinghouse
NA	0550063-001-AC	9/23/2011	FL	Highlands EnviroFuels (HEF), LLC	Ethanol Loadout	Flare	98%	BACT-PSD	State Permit Files
NA	0610096-001-AC		FL	INEOS New Planet BioEnergy	Ethanol Loadout	Flare	Not Specified	Minor Construction	State Permit Files
NA	2869-205-0047-S-02-0	12/28/2007	GA	Southwest Georgia Ethanol, LLC	Product Loadout	Flare	Not Specified	PSD Avoidance	State Permit Files
NA	0240-00092	5/1/2006	MS	Southern Ethanol Company, LLC - Rosedale	Ethanol and Industrial Grade Alcohol Loadout	Flare	Not Specified	Minor Construction	State Permit Files
NA	1840-00078	9/22/2006	MS	Southern Ethanol Company, LLC - Amory	Ethanol and Industrial Grade Alcohol Loadout	Flare	Not Specified	Minor Construction	State Permit Files
NA	1560-00075	8/3/2004	MS	Delta Ethanol, LLC	Ethanol Loadout	Afterburner (Flare)	Not Specified	Minor Construction	State Permit Files
NA	503-077-X017 - X023	?	AL	Dunhill Entities, L.P.(loading terminal for biodiesel, gasoline, ethanol)	Loading Operations	Vapor Combustion Unit (Flare)	Not Specified	Minor Construction	State Permit Files
NA	0571321-001-AC	4/5/2006	FL	United States EnviroFuels, LLC - Port Sutton Ethanol Facility	Ethanol Loadout	Flare	Not Specified	Minor Construction	State Permit Files
NA	0810213-001-AC	11/15/2005	FL	United States EnviroFuels, LLC -Port Manatee Ethanol Facility	Ethanol Loadout	Flare	Not Specified	Minor Construction	State Permit Files
NA	1310023-005-AC	1/31/2008	FL	Murphy Oil USA, Inc.	Loading Rack	Vapor Combustion Unit (Flare)	Not Specified	Minor Construction	State Permit Files
NA	F-07-047	11/27/2007	KY	The Four Rivers BioEnergy Company, Inc.	Ethanol Loadout	Flare	Not Specified	Conditional Major/Synthetic Minor	State Permit Files
NA	F-07-025	9/6/2007	KY	Kentucky 5 Star Energy, LLC	Ethanol Loadout	Regenerative Thermal Oxidizer	Not Specified	Conditional Major/Synthetic Minor	State Permit Files
NA	1050145-003-AF	3/8/2007	FL	Bartow Ethanol of Florida L.C.	Loadout	No Control	No Control	FESOP	State Permit Files

Table E-5										
Recent BACT/Permit Decisions - VOC from Wastewater Treatment										
RBLC ID	Permit No.	Date	State	Owner/Facility	Process	Corresponding Highlands Ethanol Process	Control Technology	Control Efficiency	Basis	Source
NA	F-06-033	8/31/2006	KY	Bluegrass Bioenergy, LLC	Anaerobic Wastewater Treatment Module	Anaerobic Digestion	Flare	98%	Conditional Major Permit	State Permit Files
NA	F-07-047	11/27/2007	KY	The Four Rivers BioEnergy Company, Inc.	Anaerobic Wastewater Treatment Module	Anaerobic Digestion	Flare	Not Specified	Conditional Major/Synthetic Minor	State Permit Files
NA	V-0-7-0038	10/15/2007	KY	Buffalo Trace Distillery Inc.	Wastewater Treatment Process	Anaerobic Digestion	No Control	No Control	Title V	State Permit Files
NA	V-07-024 R1	10/31/2007	KY	Constellation Spirits Inc.	Wastewater Treatment Process	Anaerobic Digestion	No Control	No Control	Conditional Major Operating	State Permit Files

Table E-6

Recent BACT/Permit Decisions - VOC from Biomass Boilers

RBLC ID	Permit No.	Date	State	Owner/Facility	Process	Control Technology	Control Efficiency	Emission Limit	Basis	Source
OH-0269	07-00534	1/5/2004	OH	Biomass Energy, LLC - South Point Power	7 Wood Fired Boilers	Catalytic Oxidation	25%	Not specified in lb/MMBtu	BACT-PSD	RBLC Clearinghouse
OH-0307	07-00534	4/4/2006	OH	Biomass Energy - South Point Biomass Generation	7 Wood Fired Boilers	Good Combustion Practices and Oxidation Catalyst	Not Specified	0.013 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
AR-0083	0117-AOP-R4	7/26/2005	AR	Potlatch Corporation - Ozan Unit	Wood Fired Boiler	Good Combustion Practices	Not Specified	0.034 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
AR-0084	0117-AOP-R4	7/26/2005	AR	Potlatch Corporation - Ozan Unit	Wood Fired Boiler	Good Combustion Practices	Not Specified	0.034 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
NH-0013	TP-B-0501	10/25/2004	NH	Public Service of New Hampshire - Schiller Station	Circulating Fluidized Bed Wood Fired Boiler No. 5	Good Combustion Practices	Not Specified	0.005 lb/MMBtu (24-hr)	Other	RBLC Clearinghouse
GA-0114	2631-115-0021-V-01-4	10/13/2004	GA	Inland Paperboard and Packaging - Rome Linerboard Mill	Solid Fuel Boiler (Bark)	Staged Combustion and Good Combustion Practices	Not Specified	0.05 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
FL-0257	PSD-FL-333	11/18/2003	FL	U.S. Sugar Corporation - Clewiston Sugar Mill & Refinery	Bagasse External Combustion	Good Combustion and Operating Practices	Not Specified	0.05 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
LA-0178	PSD-LA-77(M-2)	11/14/2003	LA	Boise Cascade Corp - Deridder Paper Mill	Wood Fired Boiler (Bark)	Good Equipment Design and Proper Combustion Techniques	Not Specified	0.034 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
LA-0218	PSD-LA-716	7/18/2007	LA	Boise Building Solutions Manufacturing, LLC - Florien Plywood Plant	Hogged Fuel Fired Boiler (wood)	High Pressure Overfire Air, Good Combustion	Not Specified	0.017 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
FL-0322	0510032-001-AC	12/23/2010	FL	Southeast Renewable Fuels (SRF), LLC	Biomass Boiler	Good Combustion Practices	Not Specified	0.010 lb/MMBtu	BACT-PSD	State Permit Files
NA	0550063-001-AC	9/23/2011	FL	Highlands EnviroFuels (HEF), LLC	Biomass Boiler (stoker)	Good Combustion Practices	Not Specified	0.017 lb/MMBtu	BACT-PSD	State Permit Files
NA	4911-061-0001-P-01-0	5/15/2009	GA	Yellow Pine Energy Company, LLC	1,529 MMBtu/hr Fluidized Bed Biomass Boilers	Good combustion	Not Specified	0.02 lb/MMBtu	BACT-PSD	State Permit Files
NA	PSD-FL-333A	11/3/2004	FL	U.S. Sugar Corporation - Clewiston Sugar Mill & Refinery	Boiler No. 8 - Bagasse	Good Combustion Practices	Not Specified	0.05 lb/MMBtu	PSD Construction	State Permit Files
NA	PSD-TX-1061	2007	TX	Nacogdoches Power Electric Generating Plant	Fluidized Bed Biomass Boiler	Good combustion	Not Specified	0.02 lb/MMBtu	BACT-PSD	State Permit Files
WA-0327	PSD-05-04	1/25/2006	WA	Sierra Pacific Industries - Skagit County Lumber Mill	Bark/Wood Waste Fired Cogeneration Boiler	No Control	No Control	0.019 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
NA	2676-095-0071-V-01-8	10/24/2007	GA	The Procter & Gamble Paper Products Company	216 MMBtu/hr Biomass Boiler	No Control	No Control	0.03 lb/MMBtu (biomass); 0.0015 lb/MMBtu (oil)	Title V	State Permit Files
NA	0430041-009	5/9/2008	MN	Corn Plus	Fluidized Bed Boiler	No Control	No Control	10 ppmdv or 95% destruction	BACT-PSD	State Permit Files

Table E-7

Recent BACT/Permit Decisions - VOC from Boilers (10-100 MMBtu/hr)

RBLC ID	Permit No.	Date	State	Owner/Facility	Process	Control Technology	Control Efficiency	Emission Limit	Basis	Source
OR-0046	24-0047	01/06/05	OR	Calpine - Turner Energy Center LLC	Auxiliary Boiler - Natural Gas	Oxidation Catalyst	90%	0.0044 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
PA-0257	17-313-001	05/07/07	PA	Sunnyside Ethanol, LLC	Auxiliary Boiler - Natural Gas	Good Combustion Practices	Not Specified	0.0014 lb/MMBtu (gas)	Other	RBLC Clearinghouse
NA	Under Review by GaEPD	06/30/05	GA	Yellow Pine Energy Company, LLC	25 MMBtu/hr Oil Fired Auxiliary Boiler	Combustion Controls	Not Specified	0.0024 lb/MMBtu	PSD Application	State Permit Files
MN-0066	05300015-004	05/16/06	MN	Northern States Power Company/XCEL Energy - Riverside Plant	Auxiliary Boiler-Natural Gas	Good Combustion	Not Specified	0.005 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
NC-0101	00986R1	09/29/05	NC	Forsyth Energy Projects, LLC - Forsyth Energy Plant	Auxiliary Boiler-Natural Gas	Good Combustion Control, and Clean Burning Low Sulfur Fuel	Not Specified	Not specified in lb/MMBtu	BACT-PSD	RBLC Clearinghouse
WI-0228	04-RV-248	10/19/04	WI	Wisconsin Public Service - Weston Plant	Auxiliary Nat Gas Fired Boiler	Natural Gas, Good Combustion Practices	Not Specified	0.0054 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
WV-0023	R14-0024	03/02/04	WV	Longview Power, LLC - Maidsville	Auxiliary Boiler-Natural Gas	Good Combustion Practices, Use of Natural Gas	Not Specified	0.0054 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
OH-0310	06-08138	02/07/08	OH	American Municipal Power Generating Station	Auxiliary Boiler - Natural Gas	No Control Listed	No Control	5.5 lb/MMCF	BACT-PSD	RBLC Clearinghouse
GA-0127	4911-067-0003-V-02-2	01/07/08	GA	Southern Company/Georgia Power - Plant McDonough	Auxiliary Boiler - Natural Gas	No Control Listed	No Control	0.0051 lb/MMBtu	LAER	RBLC Clearinghouse
TX-0499	PSD-TX 1039 AND 70861	07/24/06	TX	Sandy Creek Energy Station	Auxiliary Boiler - Natural Gas	No Control Listed	No Control	Not specified in lb/MMBtu	BACT-PSD	RBLC Clearinghouse
MD-0040	CPCN CASE NO. 9129	11/12/08	MD	CPV St. Charles	Auxiliary Boiler - Natural Gas	No Control Listed	No Control	0.002 lb/MMBtu	LAER	RBLC Clearinghouse
LA-0240	PSD-LA-747/1280-00141-V0	06/14/10	LA	Flopam Inc.	Natural Gas Fired Boilers	Good Combustion Practices	Not Specified	0.003 lb/MMBtu	LAER	RBLC Clearinghouse
NV-0049	NA	08/20/09	FL	Harrah's Operating Company, Inc.	Natural Gas Fired Boilers	Good Combustion Practices	Not Specified	0.0054 lb/MMBtu	Other	RBLC Clearinghouse
AL-0230	503-0095-X001 THRU X026	08/17/07	AL	Thyssenkrup Steel and Stainless USA, LLC	Natural Gas Fired Boilers	No Control Listed	No Control	0.0055 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
OH-0323	03-17392	06/05/08	OH	Titan Tire Corporation of Bryan	Natural Gas Fired Boilers	No Control Listed	No Control	0.0054 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
OH-0309	04-01358	05/03/07	OH	Toledo Supplier Park Paint Shop	Natural Gas Fired Boilers	No Control Listed	No Control	0.0054 lb/MMBtu	LAER	RBLC Clearinghouse
VA-0308	NA	01/14/08	VA	Warren County Facility	Auxiliary Boiler - Natural Gas	No Control Listed	No Control	0.0060 lb/MMBtu	Other	RBLC Clearinghouse

Table E-8

Recent BACT/Permit Decisions - VOC from Emergency Engines

RBLC ID	Permit No.	Date	State	Owner/Facility	Process	Control Technology	Control Efficiency	Emission Limit	Basis	Source
LA-0224	PSD-LA-726	3/20/2008	LA	Southwest Electric Power Company - Arsenal Hill Power Plant	Diesel Fire Pump	Low Sulfur Fuel, Limit Operating Hours, Proper Engine Maintenance	Not Specified	Not specified in lb/hp-hr or g/bhp-hr	BACT-PSD	RBLC Clearinghouse
IA-0084	Project Number 06-203	11/30/2006	IA	ADM Corn Processing - Clinton ADM Polymers	Fire Pump Engine	Good Combustion Practices	Not Specified	3 g/bhp-hr	BACT-PSD	RBLC Clearinghouse
OK-0100	2004-198-TV	10/21/2005	IA	Dalitalia, LLC - Muskogee Porcelain Floor Tile Pit	Emergency Generators	Good Combustion	Not Specified	0.0025 lb/hp-hr	Other	RBLC Clearinghouse
OK-0111	2004-198-C (M-1)	10/14/2005	OK	Dalitalia, LLC - Muskogee Porcelain Floor Tile Pit	Emergency Generators	Good Combustion	Not Specified	0.0025 lb/hp-hr	BACT-PSD	RBLC Clearinghouse
LA-0192	PSD-LA-704	6/6/2005	LA	Crescent City Power	Diesel Fire Water Pump	Good Engine Design and Proper Operating Practices	Not Specified	0.05 g/bhp-hr	BACT-PSD	RBLC Clearinghouse
LA-0194	PSD-LA-703	11/24/2004	LA	Sabine Pass LNG Import Terminal	Firewater Booster Pump Diesel Engines	Good Engine Design, Proper Operating Practices	Not Specified	0.15 g/bhp-hr	BACT-PSD	RBLC Clearinghouse
WI-0228	04-RV-248	10/19/2004	WI	Wisconsin Public Service - Weston Plant	Diesel Booster Pump	0.003% Sulfur Fuel, Good Combustion Practices	Not Specified	Not specified in lb/hp-hr or g/bhp-hr	BACT-PSD	RBLC Clearinghouse
WI-0228	04-RV-248	10/19/2004	WI	Wisconsin Public Service - Weston Plant	Main Fire Pump	0.003% Sulfur Fuel, Good Combustion Practices	Not Specified	Not specified in lb/hp-hr or g/bhp-hr	BACT-PSD	RBLC Clearinghouse
WV-0023	R14-0024	3/2/2004	WV	Longview Power, LLC - Maidsville	Fire Water Pump	Good Combustion Practices	Not Specified	Not specified in lb/hp-hr or g/bhp-hr	BACT-PSD	RBLC Clearinghouse
IA-0067	Project 02-528	6/17/2003	IA	Midamerican Energy Company	Diesel Fire Pump	Good Combustion Practices	Not Specified	0.35 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
OK-0090	2001-157-C M-1 PSD	3/21/2003	OK	Duke Energy Stephens, LLC	Fire Water Pump	Engine Design	Not Specified	Not specified in lb/hp-hr or g/bhp-hr	BACT-PSD	RBLC Clearinghouse
NC-0101	00986R1	9/29/2005	NC	Forsyth Energy Projects, LLC - Forsyth Energy Plant	Emergency Generator	No Control	No Control	Not specified in lb/hp-hr or g/bhp-hr	BACT-PSD	RBLC Clearinghouse
NC-0101	00986R1	9/29/2005	NC	Forsyth Energy Projects, LLC - Forsyth Energy Plant	Emergency Firewater Pump	No Control	No Control	Not specified in lb/hp-hr or g/bhp-hr	BACT-PSD	RBLC Clearinghouse
OH-0252	07-00503	12/28/2004	OH	Duke Energy Hanging Rock	Fire Water Pump	No Control	No Control	1.1 g/bhp-hr	BACT-PSD	RBLC Clearinghouse
OH-0252	07-00503	12/28/2004	OH	Duke Energy Hanging Rock	Back-up Generators	No Control	No Control	0.75 g/bhp-hr	BACT-PSD	RBLC Clearinghouse
OH-0275	14-04682	8/24/2004	OH	Cinergy - PSI Energy - Madison Station	Emergency Diesel Fire Pump	No Control	No Control	Not specified in lb/hp-hr or g/bhp-hr	BACT-PSD	RBLC Clearinghouse

Table E-9									
Recent BACT/Permit Decisions - VOC from Equipment Leaks									
RBLC ID	Permit No.	Date	State	Owner/Facility	Process	Control Technology	Control Efficiency	Basis	Source
IA-0089	07-A-955P - 07-A-982P	8/8/2007	IA	Homeland Energy Solutions LLC, PN 06-672	Equipment Leaks	Best Practices	Not Specified	BACT-PSD	RBLC Clearinghouse
OH-0303	01-01306	8/10/2006	OH	Asaliance Biofuels, LLC; Asa Bloominburg, LLC	Fugitive VOC Emission Leaks from Process Units	Leak Detection and Repair Program	Not Specified	BACT-PSD; NSPS VV	RBLC Clearinghouse
IA-0082	03-A-600P-S2	4/19/2006	IA	Golden Grain Energy	Fugitive Leaks	Leak Detection and Repair Program	Not Specified	BACT-PSD; NSPS VV	RBLC Clearinghouse
IL-0102	5010062	11/1/2005	IL	Aventine Renewable Energy	Leaking Components	Leak Detection and Repair Program	Not Specified	BACT-PSD; NSPS	RBLC Clearinghouse
FL-0322	0510032-001-AC	12/23/2010	FL	Southeast Renewable Fuels (SRF), LLC	Fugitive VOC Emission Leaks	Leak Detection and Repair Program	Not Specified	BACT-PSD	RBLC Clearinghouse
NA	0550063-001-AC	9/23/2011	FL	Highlands EnviroFuels (HEF), LLC	Fugitive VOC Emission Leaks	Leak Detection and Repair Program	Not Specified	BACT-PSD	RBLC Clearinghouse
NA	2869-205-0047-S-02-0	12/28/2007	GA	Southwest Georgia Ethanol, LLC	Equipment Leaks	Leak Detection and Repair Program	Not Specified	PSD Avoidance	State Permit Files
NA	2640-00054	5/3/2006	MS	Three Rivers Biofuels, LLC	Fugitive Methanol Emissions from Equipment	Leak Detection and Repair Program	Not Specified	Minor Construction	State Permit Files
NA	0240-00092	5/1/2006	MS	Southern Ethanol Company, LLC - Rosedale	Fugitive Components	Leak Detection and Repair Program	Not Specified	Minor Construction	State Permit Files
NA	1840-00078	9/22/2006	MS	Southern Ethanol Company, LLC - Amory	Fugitive Components	Leak Detection and Repair Program	Not Specified	Minor Construction	State Permit Files
NA	1560-00075	8/3/2004	MS	Delta Ethanol, LLC	Equipment Leaks	Leak Detection and Repair Program	Not Specified	Minor Construction	State Permit Files
NA	707-0022-X001	9/18/2007	AL	Dixie Biodiesel, LLC	Equipment Leaks	Leak Detection and Repair Program	Not Specified	Minor Construction	State Permit Files
NA	708-0029-X001, X002, X003	11/9/2007	AL	Athens Biodiesel, LLC	Equipment Leaks	Leak Detection and Repair Program	Not Specified	Minor Construction	State Permit Files
NA	413-0107-X001, X002	2/20/2008	AL	Alabama Biodiesel Corporation	Equipment Leaks	Leak Detection and Repair Program	Not Specified	Synthetic Minor Operating	State Permit Files
NA	0571321-001-AC	4/5/2006	FL	United States EnviroFuels, LLC - Port Sutton Ethanol Facility	Equipment Leaks	Leak Detection and Repair Program	Not Specified	Minor Construction	State Permit Files
NA	0810213-001-AC	11/15/2005	FL	United States EnviroFuels, LLC -Port Manatee Ethanol Facility	Equipment Leaks	Leak Detection and Repair Program	Not Specified	Minor Construction	State Permit Files
NA	F-06-033	8/31/2006	KY	Bluegrass Bioenergy, LLC	Fugitives	Leak Detection and Repair Program	Not Specified	Conditional Major Permit	State Permit Files
NA	S-06-021	2/27/2006	KY	Commonwealth Agri-Energy, LLC	Fugitives	Leak Detection and Repair Program	Not Specified	Minor Construction/Operating	State Permit Files
NA	S-07-037-R1	6/4/2007	KY	*Countrymark Cooperative, LLP*	*Pipeline Equipment*	*Best Management Practices*	*Not Specified*	*Minor Source Operating*	*State Permit Files*
NA	F-07-047	11/27/2007	KY	The Four Rivers BioEnergy Company, Inc.	Equipment Leaks	Leak Detection and Repair Program	Not Specified	Conditional Major/Synthetic Minor	State Permit Files
NA	F-07-025	9/6/2007	KY	Kentucky 5 Star Energy, LLC	Equipment Leaks	Leak Detection and Repair Program	Not Specified	Conditional Major/Synthetic Minor	State Permit Files
NA	0430041-009	5/9/2008	MN	Corn Plus	Valves, Flanges, Etc.	Leak Detection and Repair Program	Not Specified	BACT-PSD	State Permit Files
NA	1050145-003-AF	3/8/2007	FL	Bartow Ethanol of Florida L.C.	Equipment Leaks	No Control (Recordkeeping only)	No Control	FESOP	State Permit Files
NA	F-03-024	12/22/2003	KY	Heaven Hill Distilleries, Inc.	Equipment Leaks	No Control	No Control	Conditional Major Operating	State Permit Files

Table E-10										
Recent BACT/Permit Decisions - PM/PM-10 from Lime Handling										
RBLC ID	Permit No.	Date	State	Owner/Facility	Process	Control Technology	Control Efficiency	Emission Limit	Basis	Source
MT-0022	3182-00	7/21/2003	MT	Bull Mountain Dev Company - Roundup Power Project	Material Handling - Lime Handling Transfer	Baghouse	91%	0.01 gr/dscf	BACT-PSD	RBLC Clearinghouse
AR-0082	0045-AOP-R3	8/30/2005	AR	Arkansas Lime Company	Lime Storage Silo Dust Collectors	Dust Collector	99%	0.015 gr/dscf	BACT-PSD	RBLC Clearinghouse
AR-0082	0045-AOP-R3	8/30/2005	AR	Arkansas Lime Company	Lime Loadout Dust Collector	Dust Collector	99%	0.015 gr/dscf	BACT-PSD	RBLC Clearinghouse
LA-0202	PSD-LA-711	2/23/2006	LA	CLECO Power, LLC - Rodemacher Brownfield Unit	Lime Silo	Baghouse	99%	Not specified in gr/dscf	BACT-PSD	RBLC Clearinghouse
SC-0104	0420-0030-CI	2/5/2004	SC	Santee Cooper - Cross Generating Station	Limestone Handling	Baghouse	99%	0.022 gr/dscf	BACT-PSD	RBLC Clearinghouse
LA-0122	PSD-LA-93 (M-6)	8/14/2001	LA	International Paper Company - Mansfield Mill	Lime Slaker	Wet Scrubber	99.5%	Not specified in gr/dscf	BACT-PSD	RBLC Clearinghouse
CO-0055	05PR0027	2/3/2006	CO	Lamar Light & Power Power Plant	Limestone Handling/Processing/Storage	Baghouse	99.5%	Not specified in gr/dscf	BACT-PSD	RBLC Clearinghouse
ND-0024	PTC07026	9/14/2007	ND	Great River Energy - Spiritwood Station	Lime, Limestone, and Ash Handling	Baghouse	99.9%	0.005 gr/dscf	BACT-PSD	RBLC Clearinghouse
ND-0021	PTC 05005	6/3/2005	ND	Montana Dakota Utilities/Westmoreland Power - Gascoyne Gen. Sta.	Lime, Limestone, and Ash Handling	Baghouse	99.9%	0.005 gr/dscf	BACT-PSD	RBLC Clearinghouse
OH-0270	03-13527	10/14/2003	OH	Carmeuse Lime Inc. - Maple Grove Facility	Lime Material Handling #2	Baghouse	Not Specified	0.01 gr/dscf	BACT-PSD	RBLC Clearinghouse
AL-0220	411-0039-X026 -- X032	3/23/2005	AL	Chemical Lime Company - O'Neal Plant	Lime Product Handling and Storage	Baghouse	Not Specified	0.005 gr/dscf and 0.009 gr/dscf	BACT-PSD	RBLC Clearinghouse
LA-0202	PSD-LA-711	2/23/2006	LA	CLECO Power, LLC - Rodemacher Brownfield Unit	Limestone Rock Silo	Baghouse	Not Specified	Not specified in gr/dscf	BACT-PSD	RBLC Clearinghouse
WI-0233	05-DCF-412	8/16/2006	WI	Cutler Magner Company - Superior	Lime Storage and Handling	Baghouse	Not Specified	0.0114 gr/dscm	BACT-PSD	RBLC Clearinghouse
LA-0221	PSD-LA-720	11/30/2007	LA	Entergy Louisiana LLC - Little Gypsy Generating Plant	Activated Carbon & Lime Silos	Baghouse	Not Specified	No numerical limit	BACT-PSD	RBLC Clearinghouse
TX-0485	PSD-TX-684M1 /9654A/833M1	10/5/2004	TX	Inland Paperboard and Packaging - Orange Mill	Lime Silo	Baghouse	Not Specified	Not specified in gr/dscf	BACT-PSD	RBLC Clearinghouse
LA-0207	PSD-LA-93(M-7)	7/22/2004	LA	International Paper Company - Mansfield Mill	Lime Slaker	Wet Scrubber	Not Specified	Not specified in gr/dscf	BACT-PSD	RBLC Clearinghouse
LA-0223	PSD-LA-660(M-1)	1/8/2008	LA	Louisiana Generating, LLC - Big Cajun I Power Plant	Lime Silo	Baghouse	Not Specified	Not specified in gr/dscf	BACT-PSD	RBLC Clearinghouse
LA-0223	PSD-LA-660(M-1)	1/8/2008	LA	Louisiana Generating, LLC - Big Cajun I Power Plant	Limestone Storage Dome	Baghouse	Not Specified	Not specified in gr/dscf	BACT-PSD	RBLC Clearinghouse
LA-0223	PSD-LA-660(M-1)	1/8/2008	LA	Louisiana Generating, LLC - Big Cajun I Power Plant	Limestone Silo and Crusher	Baghouse	Not Specified	Not specified in gr/dscf	BACT-PSD	RBLC Clearinghouse
FL-0322	0510032-001-AC	12/23/2010	FL	Southeast Renewable Fuels (SRF), LLC	Miscellaneous Storage Silos	Baghouse	Not Specified	0.01 gr/dscf	BACT-PSD	RBLC Clearinghouse
NA	0550063-001-AC	9/23/2011	FL	Highlands EnviroFuels (HEF), LLC	Miscellaneous Storage Silos	Baghouse	Not Specified	0.01 gr/dscf	BACT-PSD	RBLC Clearinghouse
WI-0225	02-RV-147	12/3/2003	WI	Manitowoc Public Utilities	Lime Storage Silo	Baghouse	Not Specified	No numerical limit	Other	RBLC Clearinghouse
AR-0078	1139-AOP-R5	6/9/2003	AR	Nucor Corporation	Lime Silo	Baghouse	Not Specified	0.0005 gr/dscf	BACT-PSD	RBLC Clearinghouse
AR-0074	1995-AOP-R0	8/20/2003	AR	Plum Point Associates, LLC - Plum Point Energy	Material Handling - Lime	Baghouse	Not Specified	Not specified in gr/dscf	BACT-PSD	RBLC Clearinghouse
CO-0057	04UNITPB1015	7/5/2005	CO	Public Service Company of Colorado - Comanche Station	Lime Slaker	Scrubber	Not Specified	0.015 gr/dscf	BACT-PSD	RBLC Clearinghouse
CO-0057	04UNITPB1015	7/5/2005	CO	Public Service Company of Colorado - Comanche Station	Lime Silo	Baghouse	Not Specified	0.01 gr/dscf	BACT-PSD	RBLC Clearinghouse
IA-0095	PROJECT 08-126	9/19/2008	IA	Tate & Lyle Ingredients Americas, Inc.	Lime Silo	Dust Collector	Not Specified	0.005 gr/dscf	BACT-PSD	RBLC Clearinghouse
IA-0086	02-111	5/3/2007	IA	University of Northern Iowa	#4 Limestone System - Silo	Baghouse	Not Specified	0.005 gr/dscf	BACT-PSD	RBLC Clearinghouse
WV-0024	R14-0028	4/26/2006	WV	Western Greenbriar Cogeneration LLC	Limestone Handling	Baghouse	Not Specified	0.01 gr/dscf	BACT-PSD	RBLC Clearinghouse
WI-0228	04-RV-248	10/19/2004	WI	Wisconsin Public Service - Weston Plant	Lime Day Bin Vent	Baghouse	Not Specified	0.01 gr/dsc	BACT-PSD	RBLC Clearinghouse
WI-0228	04-RV-248	10/19/2004	WI	Wisconsin Public Service - Weston Plant	Lime Storage Silo Bin Vent	Baghouse	Not Specified	0.01 gr/dscf	BACT-PSD	RBLC Clearinghouse

Table E-11

Recent BACT/Permit Decisions - PM/PM-10 from Cooling Towers

RBLC ID	Permit No.	Date	State	Owner/Facility	Process	Control Technology	Basis	Source
FL-0299	PSD-FL-392	10/12/2007	FL	Progress Energy Florida - Crystal River Power Plant	Cooling Towers	0.0005% Drift Eliminator	BACT-PSD	RBLC Clearinghouse
FL-0294	1010017-008-AC	12/22/2006	FL	Progress Energy Florida - Anclote Power Plant	Cooling Towers	0.0005% Drift Eliminator	BACT-PSD	RBLC Clearinghouse
AZ-0047	1001653	12/1/2004	AZ	Dome Valley Energy Partners - Wellton Mohawk Generating Station	Mechanical Draft Cooling Towers	0.0005% Drift Eliminator	BACT-PSD	RBLC Clearinghouse
AZ-0049	1001743	9/4/2003	AZ	Allegheny Energy Supply, LLC - La Paz Generating Facility	Mechanical Draft Cooling Towers for GE Turbines	0.0005% Drift Eliminator	BACT-PSD	RBLC Clearinghouse
AZ-0049	1001743	9/4/2003	AZ	Allegheny Energy Supply, LLC - La Paz Generating Facility	Mechanical Draft Cooling Towers for Siemens Turbines	0.0005% Drift Eliminator	BACT-PSD	RBLC Clearinghouse
LA-0191	PSD-LA-700	10/12/2004	LA	Entergy New Orleans, Inc. - Michoud Electric Generating Plant	Cooling Towers	0.001% Drift Eliminator	BACT-PSD	RBLC Clearinghouse
NA	4911-061-0001-P-01-0	5/15/2009	GA	Yellow Pine Energy Company, LLC	Cooling Tower	0.001% Drift Eliminator	PSD Application	State Permit Files
LA-0206	PSD-LA-667(M-1)	2/18/2004	LA	ExxonMobil Refining and Supply Co - Baton Rouge Refinery	Cooling Towers	0.003% Drift Eliminators	BACT-PSD	RBLC Clearinghouse
IA-0092	06-A-571P - 06-A-590P	4/19/2007	IA	Southwest Iowa Renewable Energy	Cooling Towers	0.005% Drift Eliminator	BACT-PSD	RBLC Clearinghouse
WY-0064	CT-4631	10/15/2007	WY	Basin Electric Power Cooperative - Dry Fork Station	Cooling Towers	0.005% Drift Eliminator	BACT-PSD	RBLC Clearinghouse
OH-0303	01-01306	8/10/2006	OH	Asaliance Biofuels, LLC; Asa Bloominburg, LLC	Cooling Tower	0.005% Drift Eliminator	State BAT	RBLC Clearinghouse
IL-0102	5010062	11/1/2005	IL	Aventine Renewable Energy	Cooling Tower	0.005% Drift Eliminator	BACT-PSD	RBLC Clearinghouse
WI-0204	03-DCF-048	8/14/2003	WI	United Wisconsin Grain Producers - Fuel Grade Ethanol Plant	Cooling Towers	0.005% Drift Eliminator	Other	RBLC Clearinghouse
NV-0047	114	2/26/2008	NV	99 Civil Engineer Squadron of USAF - Nellis AFB	Cooling Towers	0.005% Drift Eliminator, Limits on Water Flow Rate and Solids Content	Other	RBLC Clearinghouse
WI-0207	03-DCF-184	1/21/2004	WI	Ace Ethanol - Stanley	Cooling Towers	0.005% Drift Eliminators	BACT-PSD	RBLC Clearinghouse
NC-0112	08680T09	11/23/2004	NC	Nucor Steel	Cooling Towers	0.008% Drift Eliminator	BACT-PSD	RBLC Clearinghouse
NC-0113	08680T09	11/23/2004	NC	Nucor Steel	Cooling Towers	0.008% Drift Eliminator	BACT-PSD	RBLC Clearinghouse
NA	V-0-7-0038	10/15/2007	KY	Buffalo Trace Distillery Inc.	Cooling Tower	Best Management Practices	Title V	State Permit Files
NA	F-03-024	12/22/2003	KY	Heaven Hill Distilleries, Inc.	Bottling House Cooling Tower	Best Management Practices	Conditional Major Operating	State Permit Files
LA-0148	PSD-LA-727	5/28/2008	LA	Red River Enviromental Products, LLC - Activated Carbon Facility	Cooling Towers	Drift Elimination System	BACT-PSD	RBLC Clearinghouse
LA-0213	PSD-LA-619(M-2)	2/8/2007	LA	Valero Refining - New Orleans, LLC - St. Charles Refinery	Cooling Towers	Drift Eliminators	BACT-PSD	RBLC Clearinghouse
FL-0322	0510032-001-AC	12/23/2010	FL	Southeast Renewable Fuels (SRF), LLC	Cooling Towers	0.001% Drift Eliminator	BACT-PSD	RBLC Clearinghouse
NA	0550063-001-AC	9/23/2011	FL	Highlands EnviroFuels (HEF), LLC	Cooling Towers	0.001% Drift Eliminator	BACT-PSD	RBLC Clearinghouse
AR-0077	2062-AOP-R0	7/22/2004	AR	Steelcorr, Inc. - Bluewater Project	Cooling Towers	Drift Eliminators	BACT-PSD	RBLC Clearinghouse
ID-0015	T1-9507-114-1	4/5/2004	ID	*J.R. Simplot Company - Don Siding Plant*	*Cooling Towers, Reclaim*	*Drift Eliminators*	RACT	*RBLC Clearinghouse*
IN-0108	107-16823-00038	11/21/2003	IN	Nucor Steel	Cooling Towers	Drift Eliminators	BACT-PSD	RBLC Clearinghouse
LA-0204	PSD-LA-709	7/27/2005	LA	Shintech Louisiana, LLC - Plaquemine PVC Plant	VCM Cooling Towers	Good Design, Maintenance, Integrated Drift Eliminators	BACT-PSD	RBLC Clearinghouse
SC-0104	0420-0030-CI	2/5/2004	SC	Santee Cooper - Cross Generating Station	Cooling Towers	No Control	Other	RBLC Clearinghouse
NA	2640-00054	5/3/2006	MS	Three Rivers Biofuels, LLC	Cooling Tower	No Control	Minor Construction	State Permit Files
NA	0240-00092	5/1/2006	MS	Southern Ethanol Company, LLC - Rosedale	Cooling Tower	No Control	Minor Construction	State Permit Files
NA	1840-00078	9/22/2006	MS	Southern Ethanol Company, LLC - Amory	Cooling Tower	No Control	Minor Construction	State Permit Files
NA	F-07-047	11/27/2007	KY	The Four Rivers BioEnergy Company, Inc.	Cooling Tower	No Control	Conditional Major/Synthetic Minor	State Permit Files
NA	F-06-033	8/31/2006	KY	Bluegrass Bioenergy, LLC	Cooling Tower	Not Specified	Conditional Major Permit	State Permit Files
GA-0141	4911-301-0016-P-01-0	12/17/2010	GA	Warren County Biomass Energy Facility	Cooling Towers	0.0005% Drift Eliminator	BACT-PSD	RBLC Clearinghouse
TX-0553	PSDTX1184	1/8/2010	TX	Lindale Renewable Energy	Cooling Towers	0.0005% Drift Eliminator	BACT-PSD	RBLC Clearinghouse
TX-0551	PSDTX1198	2/3/2010	TX	Panda Sherman Power Station	Cooling Towers	0.0005% Drift Eliminator	BACT-PSD	RBLC Clearinghouse
TX-0552	PSDTX1110	3/3/2010	TX	Wolf Hollow Power Plant No. 2	Cooling Towers	0.0005% Drift Eliminator	BACT-PSD	RBLC Clearinghouse
ID-0017	P-2008.0066	2/10/2009	ID	Power County Advanced Energy Center	Cooling Towers	0.0005% Drift Eliminator	BACT-PSD	RBLC Clearinghouse

Table E-12

Recent BACT/Permit Decisions - PM/PM-10 from Biomass Boilers

RBLC ID	Permit No.	Date	State	Owner/Facility	Process	Pollutant	Control Technology	Control Efficiency	Emission Limit	Basis	Source
LA-0188	PSD-LA-698	11/23/2004	LA	Inland Paperboard and Packaging - Bogalusa Mill	No. 12 Hogged Fuel Boiler (Bark)	PM-10	Wet Scrubber	80%	0.15 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
MN-0059	13700027-003	6/30/2005	MN	Hibbing Public Utilities	Wood Fired Boiler	PM-10	ESP	90%	0.025 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
ND-0022	PTC06004	5/1/2006	ND	Archer Daniels Midland Company - Northern Su n	Wood/Hull Fired Boiler	PM	ESP	95%	0.08 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
OH-0269	07-00534	1/5/2004	OH	Biomass Energy, LLC - South Point Power	7 Wood Fired Boilers	PM-10	Baghouse	98%	0.0125 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
MN-0058	13700028-005	6/30/2005	MN	City of Virginia Department of Public Utilities	Wood Fired Boiler	PM-10	ESP	98%	0.025 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
NA	0430041-009	5/9/2008	MN	Corn Plus	Fluidized Bed Boiler	PM-10	Baghouse	99%	0.8 lb/MMBtu	BACT-PSD	State Permit Files
NH-0013	TP-B-0501	10/25/2004	NH	Public Service of New Hampshire - Schiller Station	Circulating Fluidized Bed Wood Fired Boiler No. 5	PM-10	Baghouse	99%	0.025 lb/MMBtu (no avg); 0.03 lb/MMBtu (30 day); 0.01 lb/hr (24hr)	MACT	RBLC Clearinghouse
WA-0327	PSD-05-04	1/25/2006	WA	Sierra Pacific Industries - Skagit County Lumber Mill	Bark/Wood Waste Fired Cogeneration Boiler	PM-10	ESP	99%	0.02 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
WA-0335	PSD-06-02	5/22/2007	WA	Simpson Paper Company - Simpson Tacoma Kraft Company, LLC	Wood Waste Boiler	PM-10	ESP	99%	0.02 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
FL-0257	PSD-FL-333	11/18/2003	FL	U.S. Sugar Corporation - Clewiston Sugar Mill & Refinery	Bagasse External Combustion	PM	Wet Cyclone and ESP	99%	0.026 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
NA	4911-061-0001-P-01-0	5/15/2009	GA	Yellow Pine Energy Company, LLC	1.529 MMBtu/hr Fluidized Bed Biomass Boilers	PM-10	Baghouse	99%	0.018 lb/MMBtu (front & back)	BACT-PSD	State Permit Files
OH-0307	07-00534	4/4/2006	OH	Biomass Energy - South Point Biomass Generation	7 Wood Fired Boilers	PM-10	Baghouse	Not Specified	0.0064 gr/dscf	BACT-PSD	RBLC Clearinghouse
LA-0218	PSD-LA-716	7/18/2007	LA	Boise Building Solutions Manufacturing, LLC - Florien Plywood Plant	Hogged Fuel Fired Boiler (wood)	PM-10	Multiclones, Venturi Scrubber, Good Combustion Practices	Not Specified	0.1 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
WA-0329	PSD-03-04	2/11/2005	WA	Darrington Energy Cogeneration Power Plant	Wood Waste Fired Boiler	PM-10	ESP	Not Specified	0.02 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
NA	4911-119-0025-E-03-0	7/29/2008	GA	Earth Resources, Inc. - Plant Carl	400 MMBtu/hr Bubbling Fluidized Bed Biomass Boiler	PM	ESP	Not Specified	0.03 lb/MMBtu	Title V; PSD Avoidance	State Permit Files
NA	4991-119-0025-E-02-0	10/31/2006	GA	Earth Resources, Inc. - Plant Carl	335 MMBtu/hr Bubbling Fluidized Bed Biomass Boiler	PM	ESP	Not Specified	0.03 lb/MMBtu	Title V; PSD Avoidance	State Permit Files
WA-0336	PSD-06-01	11/17/2006	WA	Grays Harbor Paper, LP	Wood Waste Boiler	PM-10	Multiclones and Wet Scrubbers	Not Specified	Not specified in lb/MMBtu	BACT-PSD	RBLC Clearinghouse
WA-0336	PSD-06-01	11/17/2006	WA	Grays Harbor Paper, LP	Industrial Sized Boiler (wood waste)	PM-10	Primary and Secondary Multiclones, Packed Bed Wet Venturi Scrubber	Not Specified	Not specified in lb/MMBtu	BACT-PSD	RBLC Clearinghouse
NA	4911-149-0008-E-01-0	6/10/2008	GA	Greenway Renewable Power, LLC	719 MMBtu/hr Wood Biomass Boiler	PM	Baghouse	Not Specified	0.03 lb/MMBtu	Title V; PSD Avoidance	State Permit Files
GA-0114	2631-115-0021-V-01-4	10/13/2004	GA	Inland Paperboard and Packaging - Rome Linerboard Mill	Solid Fuel Boiler (Bark)	PM-10	ESP	Not Specified	0.025 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
MN-0074	13900114	8/23/2007	MN	Koda Energy	Biomass Boiler 3	PM	Cyclone and ESP	Not Specified	0.037 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
MN-0074	13900114	8/23/2007	MN	Koda Energy	Biomass Boiler 1	PM	Cyclone and ESP	Not Specified	0.03 lb/MMBtu on biomass	BACT-PSD	RBLC Clearinghouse
TX-0461	P1024	10/10/2003	TX	Rio Grand Valley Sugar Growers, Inc. - WR Crowley Sugar House	Boiler 1-2 Case 1 - Bagasse	PM-10	Multiclones and Wet Scrubbers	Not Specified	Not specified in lb/MMBtu	BACT-PSD	RBLC Clearinghouse
TX-0461	P1024	10/10/2003	TX	Rio Grand Valley Sugar Growers, Inc. - WR Crowley Sugar House	Boiler 1-2 Case 2 - Bagasse	PM-10	Multiclones and Wet Scrubbers	Not Specified	Not specified in lb/MMBtu	BACT-PSD	RBLC Clearinghouse
TX-0461	P1024	10/10/2003	TX	Rio Grand Valley Sugar Growers, Inc. - WR Crowley Sugar House	Boiler 3-4 Case 1 - Bagasse	PM-10	Multiclones and Wet Scrubbers	Not Specified	Not specified in lb/MMBtu	BACT-PSD	RBLC Clearinghouse
TX-0461	P1024	10/10/2003	TX	Rio Grand Valley Sugar Growers, Inc. - WR Crowley Sugar House	Boiler 3-4 Case 2 - Bagasse	PM-10	Multiclones and Wet Scrubbers	Not Specified	Not specified in lb/MMBtu	BACT-PSD	RBLC Clearinghouse
TX-0461	P1024	10/10/2003	TX	Rio Grand Valley Sugar Growers, Inc. - WR Crowley Sugar House	Boiler 6 - Bagasse	PM-10	Multiclones and Wet Scrubbers	Not Specified	Not specified in lb/MMBtu	BACT-PSD	RBLC Clearinghouse
FL-0322	0510032-001-AC	12/23/2010	FL	Southeast Renewable Fuels (SRF), LLC	Biomass Boiler	PM-10	Wet Cyclone and ESP	Not Specified	0.015 lb/MMBtu front half only	BACT-PSD	State Permit Files
NA	0550063-001-AC	9/23/2011	FL	Highlands EnviroFuels (HEF), LLC	Biomass Boiler	PM-10	Wet Cyclone and ESP	Not Specified	0.015 lb/MMBtu front half only	BACT-PSD	State Permit Files
NA	05600T10	11/15/2006	NC	Suez Energy BioPower, Inc. - North Cove	Wood/Carpet Waste-Fired Boiler	PM	Multiclone and Variable Throat Venturi	Not Specified	0.38 lb/MMBtu (wood)	Title V; PSD Avoidance	State Permit Files
NA	2676-095-0071-V-01-8	10/24/2007	GA	The Procter & Gamble Paper Products Company	216 MMBtu/hr Biomass Boiler	PM	Wet ESP	Not Specified	0.03 lb/MMBtu (biomass); 0.024lb/MMBtu (oil)	Title V	State Permit Files
NA	PSD-FL-389	12/6/2007	FL	U.S. Sugar Corporation - Clewiston Sugar Mill & Refinery	Boiler No. 7 - Permitting of Wood Chips	PM	Wet sand separator and ESP	Not Specified	0.03 lb/MMBtu; 22 lb/hr	PSD Construction	State Permit Files
NA	PSD-FL-333A	11/3/2004	FL	U.S. Sugar Corporation - Clewiston Sugar Mill & Refinery	Boiler No. 8 - Bagasse	PM-10	Wet Cyclone and ESP	Not Specified	0.026 lb/MMBtu	PSD Construction	State Permit Files
NA	2048-205-0037-V-03-0	12/3/2002	GA	Wind Gap Farms	87.5 MMBtu/hr Wood Fired Boiler	PM	Scrubber	Not Specified	Not specified in lb/MMBtu	Title V	State Permit Files
NA	PSD-TX-1061	6/29/1905	TX	Nacogdoches Power Electric Generating Plant	Fluidized Bed Biomass Boiler	PM-10	Baghouse	Not Specified	0.015 lb/MMBtu front half; 0.032 lb/MMBtu total	BACT-PSD	State Permit Files
NA	PSD-TX-1061	2007	TX	Nacogdoches Power Electric Generating Plant	Fluidized Bed Biomass Boiler	PM	Baghouse	Not Specified	0.015 lb/MMBtu front half; 0.032 lb/MMBtu total	BACT-PSD	State Permit Files

Table E-13

Recent BACT/Permit Decisions - PM/PM-10 from Natural Gas Boilers (10-100 MMBtu/hr)

RBLC ID	Permit No.	Date	State	Owner/Facility	Process	Pollutant	Control Technology	Control Efficiency	Emission Limit	Basis	Source
OR-0046	24-0047	1/6/05	OR	Calpine - Turner Energy Center LLC	Auxiliary Boiler - Natural Gas	PM-10	Use of Natural Gas	Not Specified	No numerical limit	BACT-PSD	RBLC Clearinghouse
NC-0101	00986R1	9/29/05	NC	Forsyth Energy Projects, LLC - Forsyth Energy Plant	Auxiliary Boiler - Natural Gas	PM-10	Low NOx Burners, Good Combustion Control, and Clean Burning Low Sulfur Fuel	Not Specified	0.007 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
WV-0023	R14-0024	3/2/04	WV	Longview Power, LLC - Maidsville	Auxiliary Boiler - Natural Gas	PM-10	Clean Fuels and Good Combustion Practices	Not Specified	0.0022 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
WI-0228	04-RV-248	10/19/04	WI	Wisconsin Public Service - Weston Plant	Auxiliary Boiler - Natural Gas	PM-10	Natural Gas Only, Good Combustion Practices	Not Specified	0.0075 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
OH-0310	06-08138	2/7/08	OH	American Municipal Power Generating Station	Auxiliary Boiler - Natural Gas	PM-10	No Control Listed	No Control	7.6 lb/MMCF	BACT-PSD	RBLC Clearinghouse
TX-0499	PSD-TX 1039 AND 70861	7/24/06	TX	Sandy Creek Energy Station	Auxiliary Boiler - Natural Gas	PM	No Control Listed	No Control	Not specified in lb/MMBtu	BACT-PSD	RBLC Clearinghouse
PA-0257	17-313-001	5/7/07	PA	Sunnyside Ethanol, LLC	Auxiliary Boiler-Natural Gas and Distillate Oil	PM-10	Limited Operating House & Good Combustion Practices	Not Specified	0.0075 lb/MMBtu (gas); 0.017 lb/MMBtu (#2 oil)	BACT-PSD	RBLC Clearinghouse
MD-0040	CPCN CASE NO. 9129	11/12/08	MD	CPV St. Charles	Auxiliary Boiler - Natural Gas	PM	No Control Listed	No Control	0.005 lb/MMBtu (3-hr avg)	BACT-PSD	RBLC Clearinghouse
MD-0040	CPCN CASE NO. 9129	11/12/08	MD	CPV St. Charles	Auxiliary Boiler - Natural Gas	PM-10 filt	No Control Listed	No Control	0.005 lb/MMBtu (3-hr avg)	BACT-PSD	RBLC Clearinghouse
MD-0040	CPCN CASE NO. 9129	11/12/08	MD	CPV St. Charles	Auxiliary Boiler - Natural Gas	PM-2.5 filt	No Control Listed	No Control	0.005 lb/MMBtu (3-hr avg)	LAER	RBLC Clearinghouse
OH-0323	03-17392	6/5/08	OH	Titan Tire Corporation of Bryan	Natural Gas Fired Boilers	PM	No Control Listed	No Control	0.02 lb/MMBtu	Other	RBLC Clearinghouse
OH-0323	03-17392	6/5/08	OH	Titan Tire Corporation of Bryan	Natural Gas Fired Boilers	PM-10 filt	No Control Listed	No Control	0.002 lb/MMBtu	Other	RBLC Clearinghouse
OH-0309	04-01358	5/3/07	OH	Toledo Supplier Park Paint Shop	Natural Gas Fired Boilers	PM	No Control Listed	No Control	0.02 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
OH-0309	04-01358	5/3/07	OH	Toledo Supplier Park Paint Shop	Natural Gas Fired Boilers	PM-10 filt	No Control Listed	No Control	0.007 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
OR-0048	25-0016-ST-02	12/29/10	OR	Carty Plant	Natural Gas Fired Boilers	PM-10 filt	No Control Listed	No Control	0.02 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
NV-0049	NA	8/20/09	NV	Harrah's Operating Company, Inc.	Natural Gas Fired Boilers	PM-10 filt	Operate in accordance with mfg recommendations	No Control	0.0075 lb/MMBtu	Other	RBLC Clearinghouse
AL-0230	503-0095-X001 thru X026	8/17/07	AL	Thyssenkrup Steel and Stainless USA, LLC	Natural Gas Fired Boilers	PM-10 filt	Operate in accordance with mfg recommendations	No Control	0.0076 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
LA-0246	PSD-LA-619(M6)	12/31/10	LA	St. Charles Refinery	Natural Gas Fired Boilers	PM-10 tot	Natural Gas Only, Good Combustion Practices	Not Specified	0.007 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
LA-0240	PSD-LA-747/1280-00141-V0	6/14/10	LA	Flopam Inc.	Natural Gas Fired Boilers	PM-10 tot	Natural Gas Only	Not Specified	0.004 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
LA-0240	PSD-LA-747/1280-00141-V0	6/14/10	LA	Flopam Inc.	Natural Gas Fired Boilers	PM tot	Natural Gas Only	Not Specified	0.005 lb/MMBtu	BACT-PSD	RBLC Clearinghouse

Table E-14

Recent BACT/Permit Decisions - PM/PM-10 from Emergency Engines

RBLC ID	Permit No.	Date	State	Owner/Facility	Process	Control Technology	Control Efficiency	Emission Limit	Basis	Source
CA-1144	SE 02-01	4/25/2007	CA	Caithness Blythe II, LLC - Blythe Energy Project II	Fire Pump	0.05% Sulfur Fuel	Not Specified	Not specified in lb/hp-hr or g/bhp-hr	BACT-PSD	RBLC Clearinghouse
LA-0192	PSD-LA-704	6/6/2005	LA	Crescent City Power	Diesel Fire Water Pump	Good Engine Design and Proper Operating Practices	Not Specified	0.15 g/bhp-hr	BACT-PSD	RBLC Clearinghouse
OK-0100	2004-198-TV	10/21/2005	OK	Dalitalia, LLC - Muskogee Porcelain Floor Tile Pit	Emergency Generators	Good Combustion	Not Specified	0.0022 lb/hp-hr	Other	RBLC Clearinghouse
OK-0111	2004-198-C (M-1)	10/14/2005	OK	Dalitalia, LLC - Muskogee Porcelain Floor Tile Pit	Emergency Generators	Good Combustion	Not Specified	0.0022 lb/hp-hr	BACT-PSD	RBLC Clearinghouse
OK-0090	2001-157-C M-1 PSD	3/21/2003	OK	Duke Energy Stephens, LLC	Fire Water Pump	Combustion Control and Good Engine Design	Not Specified	0.31 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
OH-0254	06-06792	8/14/2003	OH	Duke Energy Washington County LLC	Emergency Diesel Fire Pump Engine	Low Sulfur Fuel, Combustion Control	Not Specified	1 g/bhp-hr	BACT-PSD	RBLC Clearinghouse
NA	4911-149-0008-E-01-0	6/10/2008	GA	Greenway Renewable Power, LLC	1500 kW Biodiesel Emergency Generator	200 hr/yr (100 hr/yr non-emergency time); 0.05% Sulfur Fuel (0.0015% after 10/1/10)	Not Specified	0.15 g/hp-hr	Title V; PSD Avoidance	State Permit Files
WV-0023	R14-0024	3/2/2004	WV	Longview Power, LLC - Maidsville	Fire Water Pump	Good Combustion Practices	Not Specified	Not specified in lb/hp-hr or g/bhp-hr	BACT-PSD	RBLC Clearinghouse
CA-1073	418342	8/14/2003	CA	Los Angeles County Probation/FAC Planning/ISD	Fire Pump, Compression Ignition	Operation Limited to 200 hr/yr	Not Specified	0.14 g/bhp-hr	BACT-PSD	RBLC Clearinghouse
IA-0067	Project 02-528	6/17/2003	IA	Midamerican Energy Company	Diesel Fire Pump	Good Combustion Practices	Not Specified	0.31 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
LA-0194	PSD-LA-703	11/24/2004	LA	Sabine Pass LNG Import Terminal	Firewater Booster Pump Diesel Engines	Low Sulfur Fuel, Good Engine Design, Proper Operating Practices	Not Specified	0.09 g/bhp-hr	BACT-PSD	RBLC Clearinghouse
LA-0224	PSD-LA-726	3/20/2008	LA	Southwest Electric Power Company - Arsenal Hill Power Plant	Diesel Fire Pump	Low Sulfur Fuel, Limit Operating Hours, Proper Engine Maintenance	Not Specified	Not specified in lb/hp-hr or g/bhp-hr	BACT-PSD	RBLC Clearinghouse
WI-0228	04-RV-248	10/19/2004	WI	Wisconsin Public Service - Weston Plant	Diesel Booster Pump	0.003% Sulfur Fuel, Good Combustion Practices	Not Specified	Not specified in lb/hp-hr or g/bhp-hr	BACT-PSD	RBLC Clearinghouse
WI-0228	04-RV-248	10/19/2004	WI	Wisconsin Public Service - Weston Plant	Main Fire Pump	0.003% Sulfur Fuel, Good Combustion Practices	Not Specified	Not specified in lb/hp-hr or g/bhp-hr	BACT-PSD	RBLC Clearinghouse
OH-0275	14-04682	8/24/2004	OH	Cinergy - PSI Energy - Madison Station	Emergency Diesel Fire Pump	No Control	No Control	Not specified in lb/hp-hr or g/bhp-hr	BACT-PSD	RBLC Clearinghouse
OH-0252	07-00503	12/28/2004	OH	Duke Energy Hanging Rock	Fire Water Pump	No Control	No Control	1.1 g/bhp-hr	BACT-PSD	RBLC Clearinghouse
OH-0252	07-00503	12/28/2004	OH	Duke Energy Hanging Rock	Back-up Generators	No Control	No Control	0.4 g/bhp-hr	BACT-PSD	RBLC Clearinghouse
NC-0101	00986R1	9/29/2005	NC	Forsyth Energy Projects, LLC - Forsyth Energy Plant	Emergency Generator	No Control	No Control	Not specified in lb/hp-hr or g/bhp-hr	BACT-PSD	RBLC Clearinghouse
NC-0101	00986R1	9/29/2005	NC	Forsyth Energy Projects, LLC - Forsyth Energy Plant	Emergency Firewater Pump	No Control	No Control	Not specified in lb/hp-hr or g/bhp-hr	BACT-PSD	RBLC Clearinghouse
NE-0031	58343C01	3/9/2005	NE	Omaha Public Power District - Nebraska City Station	Emergency Generator	No Control	No Control	Not specified in lb/hp-hr or g/bhp-hr	Other	RBLC Clearinghouse

Table E-15										
Recent BACT/Permit Decisions - NOx from Biomass Boilers										
RBLC ID	Permit No.	Date	State	Owner/Facility	Process	Control Technology	Control Efficiency	Emission Limit	Basis	Source
WA-0327	PSD-05-04	1/25/2006	WA	Sierra Pacific Industries - Skagit County Lumber Mill	Bark/Wood Waste Fired Cogeneration Boiler	SNCR	48%	0.13 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
FL-0257	PSD-FL-333	11/18/2003	FL	U.S. Sugar Corporation - Clewiston Sugar Mill & Refinery	Bagasse External Combustion	SNCR with Good Combustion and Operating Practices	50%	0.14 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
MN-0058	13700028-005	6/30/2005	MN	City of Virginia Department of Public Utilities	Wood Fired Boiler	SNCR	50%	0.15 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
MN-0059	13700027-003	6/30/2005	MN	Hibbing Public Utilities	Wood Fired Boiler	SNCR	50%	0.15 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
NA	4911-061-0001-P-01-0	5/15/2009	GA	Yellow Pine Energy Company, LLC	1,529 MMBtu/hr Fluidized Bed Biomass Boilers	Low NOx Burner and SNCR	55%	0.10 lb/MMBtu	BACT-PSD	State Permit Files
NH-0013	TP-B-0501	10/25/2004	NH	Public Service of New Hampshire - Schiller Station	Circulating Fluidized Bed Wood Fired Boiler No. 5	SNCR	65%	0.075 lb/MMBtu (24-hr); 0.6 lb/MMBtu (30 day); 1.6 lb/MW (30 day)	Other	RBLC Clearinghouse
OH-0307	07-00534	4/4/2006	OH	Biomass Energy - South Point Biomass Generation	7 Wood Fired Boilers	SCR	80%	0.44 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
OH-0269	07-00534	1/5/2004	OH	Biomass Energy, LLC - South Point Power	7 Wood Fired Boilers	SCR	80%	0.44 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
FL-0301	PSD-FL-389	12/6/2007	FL	U.S. Sugar Corporation - Clewiston Sugar Mill & Refinery	Bagasse & Woodchip Fired Boiler	Boiler Design and Operation	Not Specified	0.31 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
MN-0074	13900114	8/23/2007	MN	Koda Energy	Biomass Boiler 3	SNCR	Not Specified	0.25 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
MN-0074	13900114	8/23/2007	MN	Koda Energy	Biomass Boiler 4	SNCR	Not Specified	0.18 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
WA-0335	PSD-06-02	5/22/2007	WA	Simpson Paper Company - Simpson Tacoma Kraft Company, LLC	Wood Waste Boiler	Proper Combustion Controls with Overfire Air	Not Specified	0.2 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
ND-0022	PTC06004	5/1/2006	ND	Archer Daniels Midland Company - Northern Su n	Wood/Hull Fired Boiler	Combustion Controls	Not Specified	0.2 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
WA-0337	PSD-01-07 Amendment 1	2/1/2006	WA	Boise Cascade Corp - Boise White Paper, LLC	Wood/Bark Boilers	Overfire Air	Not Specified	0.3 lb/MMBtu	Other	RBLC Clearinghouse
WA-0329	PSD-03-04	2/11/2005	WA	Darrington Energy Cogeneration Power Plant	Wood Waste Fired Boiler	SNCR	Not Specified	0.12 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
LA-0188	PSD-LA-698	11/23/2004	LA	Inland Paperboard and Packaging - Bogalusa Mill	No. 12 Hogged Fuel Boiler (Bark)	Low NOx Burners, Overfire Air, Good Combustion Practices	Not Specified	0.45 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
TX-0461	P1024	10/10/2003	TX	Rio Grand Valley Sugar Growers, Inc. - WR Crowley Sugar House	Boiler 1-2 Case 1 - Bagasse	Good Combustion Practices	Not Specified	Not specified in lb/MMBtu	BACT-PSD	RBLC Clearinghouse
TX-0461	P1024	10/10/2003	TX	Rio Grand Valley Sugar Growers, Inc. - WR Crowley Sugar House	Boiler 1-2 Case 2 - Bagasse	Good Combustion Practices	Not Specified	Not specified in lb/MMBtu	BACT-PSD	RBLC Clearinghouse
TX-0461	P1024	10/10/2003	TX	Rio Grand Valley Sugar Growers, Inc. - WR Crowley Sugar House	Boiler 3-4 Case 1 - Bagasse	Good Combustion Practices	Not Specified	Not specified in lb/MMBtu	BACT-PSD	RBLC Clearinghouse
TX-0461	P1024	10/10/2003	TX	Rio Grand Valley Sugar Growers, Inc. - WR Crowley Sugar House	Boiler 3-4 Case 2 - Bagasse	Good Combustion Practices	Not Specified	Not specified in lb/MMBtu	BACT-PSD	RBLC Clearinghouse
TX-0461	P1024	10/10/2003	TX	Rio Grand Valley Sugar Growers, Inc. - WR Crowley Sugar House	Boiler 6 - Bagasse	Good Combustion Practices	Not Specified	Not specified in lb/MMBtu	BACT-PSD	RBLC Clearinghouse
LA-0218	PSD-LA-716	7/18/2007	LA	Boise Building Solutions Manufacturing, LLC - Florien Plywood Plant	Hogged Fuel Fired Boiler (wood)	Good Combustion Practices, Boiler Design and Operation	Not Specified	0.22 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
FL-0322	0510032-001-AC	12/23/2010	FL	Southeast Renewable Fuels (SRF), LLC	Biomass Boiler	SNCR with Good CombustionPractices	Not Specified	0.08 lb/MMBtu (30-day rolling)	BACT-PSD	State Permit Files
NA	0550063-001-AC	9/23/2011	FL	Highlands EnviroFuels (HEF), LLC	Biomass Boiler	SNCR with Good Combustion Practices	Not Specified	0.10 lb/MMBtu (30-day rolling)	BACT-PSD	State Permit Files
NA	4911-149-0006-E-01-0	6/10/2008	GA	Greenway Renewable Power, LLC	719 MMBtu/hr Wood Biomass Boiler	SNCR	Not Specified	Meet Db Standards	Title V; PSD Avoidance	State Permit Files
NA	4911-119-0025-E-03-0	7/29/2008	GA	Earth Resources, Inc. - Plant Carl	400 MMBtu/hr Bubbling Fluidized Bed Biomass Boiler	SNCR	Not Specified	Meet Db Standards	Title V; PSD Avoidance	State Permit Files
NA	2676-095-0071-V-01-8	10/24/2007	GA	The Procter & Gamble Paper Products Company	216 MMBtu/hr Biomass Boiler	Overfire Air, Good Combustion Practices	Not Specified	0.28 lb/MMBtu	BACT-PSD; Title V	State Permit Files
NA	PSD-FL-333A	11/3/2004	FL	U.S. Sugar Corporation - Clewiston Sugar Mill & Refinery	Boiler No. 8 - Bagasse	SNCR	Not Specified	0.14 lb/MMBtu	PSD Construction	State Permit Files
NA	PSD-FL-389	12/6/2007	FL	U.S. Sugar Corporation - Clewiston Sugar Mill & Refinery	Boiler No. 7 - Permitting of Wood Chips	Good Combustion Practices, Overfire Air, Low Nitrogen Content Fuel	Not Specified	0.31 lb/MMBtu	PSD Construction	State Permit Files
NA	0430041-009	5/9/2008	MN	Com Plus	Fluidized Bed Boiler	Ammonia Injection (SNCR)	Not Specified	0.17 lb/MMBtu	BACT-PSD	State Permit Files
NA	PSD-TX-1061	2007	TX	Nacogdoches Power Electric Generating Plant	Fluidized Bed Biomass Boiler	Low NOx fluidized bed combustion and SNCR	Not Specified	0.1 lb/MMBtu	BACT-PSD	State Permit Files

Table E-16

Recent BACT/Permit Decisions - NOx from Natural Gas Boilers (10-100 MMBtu/hr)

RBLC ID	Permit No.	Date	State	Owner/Facility	Process	Control Technology	Control Efficiency	Emission Limit	Basis	Source
NA	0430041-009	05/09/08	MN	Corn Plus	Auxiliary Boilers (Natural Gas/Propane)	Low NOx Burners	Not Specified	0.04 lb/MMBtu	BACT-PSD	State Permit Files
VA-0308	NA	01/14/08	VA	Warren County Facility	Auxiliary Boiler - Natural Gas	Not specified	Not Specified	0.011 lb/MMBtu	NA	RBLC Clearinghouse
OR-0048	25-0016-ST-02	12/29/10	OR	Carty Plant	Natural Gas Fired Boiler	Low NOx Burners	Not Specified	0.05 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
NH-0015	TP-0014	02/27/09	NH	Concord Steam Corporation	Auxiliary Boiler - Natural Gas	Low NOx Burners w/ FGR	Not Specified	0.049 lb/MMBtu	LAER	RBLC Clearinghouse
MD-0040	CPCN CASE NO. 9129	2/27/09	MD	CPV St. Charles	Auxiliary Boiler - Natural Gas	Low NOx Burners w/ FGR	Not Specified	0.011 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
LA-0240	PSD-LA-747/1280-00141-V0	11/12/08	LA	Flopam Inc.	Natural Gas Fired Boilers	Ultra Low NOx Burners	Not Specified	0.015 lb/MMBtu	LAER	RBLC Clearinghouse
FL-0286	PSD-FL-354 AND 0990646-001-AC	06/14/10	FL	FPL West County Energy Center	Auxiliary Boiler - Natural Gas	Not specified	Not Specified	0.05 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
NV-0049	NA	8/20/09	NV	Harrah's Operating Company, Inc.	Natural Gas Fired Boilers	Low NOx Burners w/ FGR	70%	0.035 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
OH-0323	03-17392	6/5/08	OH	Titan Tire Corporation of Bryan	Natural Gas Fired Boilers	Not specified	Not Specified	0.049 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
OH-0309	04-01358	5/3/07	OH	Toledo Supplier Park Paint Shop	Natural Gas Fired Boilers	Low NOx Burners w/ FGR	Not Specified	0.035 lb/MMBtu	LAER	RBLC Clearinghouse
AL-0230	503-0095-X001 thru X026	8/17/07	AL	Thyssenkrup Steel and Stainless USA, LLC	Natural Gas Fired Boilers	Ultra Low NOx Burners	Not Specified	0.035 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
LA-0246	PSD-LA-619(M6)	12/31/10	LA	St. Charles Refinery	Natural Gas Fired Boilers	Ultra Low NOx Burners and/or SCR	Not Specified	0.04 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
GA-0130	3711-285-0084-P-01-0	7/27/07	GA	Kia Motors Manufacturing Georgia	Natural Gas Fired Boilers	Low NOx Burners	Not Specified	0.037 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
MD-0037	NSR-2007-01	1/28/08	MD	Medimmune Frederick Camput	Natural Gas Fired Boilers	Ultra Low NOx Burners	Not Specified	0.011 lb/MMBtu	LAER	RBLC Clearinghouse
MN-0070	06100067-001	9/7/07	MN	Minnesota Steel Industries, LLC	Natural Gas Fired Boilers	Not specified	Not Specified	0.035 lb/MMBtu (3-hr avg)	BACT-PSD	RBLC Clearinghouse

Table E-17

Recent BACT/Permit Decisions - NOx from Emergency Engines

RBLC ID	Permit No.	Date	State	Owner/Facility	Process	Control Technology	Control Efficiency	Emission Limit	Basis	Source
MT-0022	3182-00	7/21/2003	MT	Bull Mountain Dev Company - Roundup Power Project	Emergency Generator	Limited to 200 hr/yr	97.7%	97.7% reduction based on hourly operational limit	BACT-PSD	RBLC Clearinghouse
PA-0257	17-313-001	5/7/2007	PA	Sunnyside Ethanol, LLC	Emergency Generators	Ignition Retard and 300 hr/yr limit	Not Specified	5.39 g/Bhp-hr	LAER	RBLC Clearinghouse
LA-0224	PSD-LA-726	3/20/2008	LA	Southwest Electric Power Company - Arsenal Hill Power Plant	Diesel Fire Pump	Low Sulfur Fuel, Limit Operating Hours, Proper Engine Maintenance	Not Specified	Not specified in g/bhp-hr or lb/hp-hr	BACT-PSD	RBLC Clearinghouse
CA-1144	SE 02-01	4/25/2007	CA	Caithness Blythe II, LLC - Blythe Energy Project II	Fire Pump	0.05% Sulfur Fuel	Not Specified	Not specified in g/bhp-hr or lb/hp-hr	BACT-PSD	RBLC Clearinghouse
LA-0192	PSD-LA-704	6/6/2005	LA	Crescent City Power	Diesel Fire Water Pump	Good Engine Design and Proper Operating Practices	Not Specified	9.5 g/bph-hr	BACT-PSD	RBLC Clearinghouse
MO-0067	122004-017	12/29/2004	MO	Aquila, Inc - South Harper Peaking Facility	Emergency Diesel Fire Pump	Ignition Timing Retard	Not Specified	No numerical limit	BACT-PSD	RBLC Clearinghouse
LA-0194	PSD-LA-703	11/24/2004	LA	Sabine Pass LNG Import Terminal	Firewater Booster Pump Diesel Engines	Good Engine Design, Proper Operating Practices	Not Specified	5.2 g/bhp-hr	BACT-PSD	RBLC Clearinghouse
WI-0228	04-RV-248	10/19/2004	WI	Wisconsin Public Service - Weston Plant	Diesel Booster Pump	0.003% Sulfur Fuel, Good Combustion Practices, Ignition Timing Retard	Not Specified	Not specified in g/bhp-hr or lb/hp-hr	BACT-PSD	RBLC Clearinghouse
WI-0228	04-RV-248	10/19/2004	WI	Wisconsin Public Service - Weston Plant	Main Fire Pump	0.003% Sulfur Fuel, Good Combustion Practices, Ignition Timing Retard	Not Specified	Not specified in g/bhp-hr or lb/hp-hr	BACT-PSD	RBLC Clearinghouse
WV-0023	R14-0024	3/2/2004	WV	Longview Power, LLC - Maidsville	Fire Water Pump	Combustion Controls with Operational Limitations	Not Specified	56 g/bhp-hr	BACT-PSD	RBLC Clearinghouse
AK-0059	307CP01	9/29/2003	AK	USAF Eareckson Air Station	Fire Water Pump	Good Combustion Practices	Not Specified	No numerical limit	BACT-PSD	RBLC Clearinghouse
CA-1073	418342	8/14/2003	CA	Los Angeles County Probation/FAC Planning/ISD	Fire Pump, Compression Ignition	5.5 Degrees Fuel Injection Timing Retard-After Cooler by Raw Water	Not Specified	4.2 g/bhp-hr	BACT-PSD	RBLC Clearinghouse
OH-0254	06-06792	8/14/2003	OH	Duke Energy Washington County LLC	Emergency Diesel Fire Pump Engine	Low Sulfur Fuel, Combustion Control	Not Specified	14.5 g/bhp-hr	BACT-PSD	RBLC Clearinghouse
IA-0067	Project 02-528	6/17/2003	IA	Midamerican Energy Company	Diesel Fire Pump	Good Combustion Practices	Not Specified	4.41 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
OK-0090	2001-157-C M-1 PSD	3/21/2003	OK	Duke Energy Stephens, LLC	Fire Water Pump	Engine Design and Hours Limit (<100 hr/yr)	Not Specified	4.97 g/bhp-hr; 4.41 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
WA-0291	EFSEC/2001-03	1/3/2003	WA	Wallula Generation, LLC - Wallula Power Plant	Emergency Diesel Generator	Limited to 200 hr/yr	Not Specified	568 ppmdv	Other	RBLC Clearinghouse
NC-0101	00986R1	9/29/2005	NC	Forsyth Energy Projects, LLC - Forsyth Energy Plant	Emergency Generator	No Control	No Control	7.7 g/bhp-hr	BACT-PSD	RBLC Clearinghouse
NC-0101	00986R1	9/29/2005	NC	Forsyth Energy Projects, LLC - Forsyth Energy Plant	Emergency Firewater Pump	No Control	No Control	7.7 g/bhp-hr	BACT-PSD	RBLC Clearinghouse
OH-0252	07-00503	12/28/2004	OH	Duke Energy Hanging Rock	Fire Water Pump	No Control	No Control	14 g/bhp-hr	BACT-PSD	RBLC Clearinghouse
OH-0252	07-00503	12/28/2004	OH	Duke Energy Hanging Rock	Back-up Generators	No Control	No Control	6.9 g/bhp	BACT-PSD	RBLC Clearinghouse
OH-0275	14-04682	8/24/2004	OH	Cinergy - PSI Energy - Madison Station	Emergency Diesel Fire Pump	No Control	No Control	Not specified in g/bhp-hr or lb/hp-hr	BACT-PSD	RBLC Clearinghouse

Table E-18

Recent BACT/Permit Decisions - SO2 from Biomass Boilers

RBLC ID	Permit No.	Date	State	Owner/Facility	Process	Control Technology	Control Efficiency	Emission Limit	Basis	Source
OH-0307	07-00534	4/4/2006	OH	Biomass Energy - South Point Biomass Generation	7 Wood Fired Boilers	Spray Dryer Absorber or Sodium Bicarbonate Injection System	20%	0.087 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
OH-0269	07-00534	1/5/2004	OH	Biomass Energy, LLC - South Point Power	7 Wood Fired Boilers	Dry Sodium Bicarbonate Injection or Spray Dryer Absorber	20%	0.087 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
NH-0013	TP-B-0501	10/25/2004	NH	Public Service of New Hampshire - Schiller Station	Circulating Fluidized Bed Wood Fired Boiler No. 5	Lime Injection	70%	0.02 lb/MMBtu	Other	RBLC Clearinghouse
NA	4911-061-0001-P-01-0	5/15/2009	GA	Yellow Pine Energy Company, LLC	1,529 MMBtu/hr Fluidized Bed Biomass Boilers	Dry Scrubber	88.9%	*0.014 lb/MMBtu (30-day)*	BACT-PSD	State Permit Files
LA-0188	PSD-LA-698	11/23/2004	LA	Inland Paperboard and Packaging - Bogalusa Mill	No. 12 Hogged Fuel Boiler (Bark)	Limit Fuel Oil Capacity Factor to <=10%	Not Specified	1.54 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
FL-0257	PSD-FL-333	11/18/2003	FL	U.S. Sugar Corporation - Clewiston Sugar Mill & Refinery	Bagasse External Combustion	Bagasse and Distillate Oil <0.05% S	Not Specified	0.06 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
FL-0322	0510032-001-AC	12/23/2010	FL	Southeast Renewable Fuels (SRF), LLC	Biomass Boiler	Dry sorbent injection, gas desulfurization of biogas	Not Specified	0.06 lb/MMBtu (30-day rolling)	BACT-PSD	State Permit Files
NA	0550063-001-AC	9/23/2011	FL	Highlands EnviroFuels (HEF), LLC	Biomass Boiler	Dry sorbent injection	Not Specified	0.06 lb/MMBtu (30-day rolling)	BACT-PSD	State Permit Files
NA	4911-149-0008-E-01-0	6/10/2008	GA	Greenway Renewable Power, LLC	719 MMBtu/hr Wood Biomass Boiler	Spray Dry Scrubber, 3% Sulfur Fuel	Not Specified	Meet Db Standards	Title V; PSD Avoidance	State Permit Files
NA	4911-119-0025-E-03-0	7/29/2008	GA	Earth Resources, Inc. - Plant Carl	400 MMBtu/hr Bubbling Fluidized Bed Biomass Boiler	Dry Scrubber, 3% Sulfur Fuel	Not Specified	Meet Db Standards	Title V; PSD Avoidance	State Permit Files
NA	2048-205-0037-V-03-0	12/3/2002	GA	Wind Gap Farms	87.5 MMBtu/hr Wood Fired Boiler	2.5% Sulfur Fuel	Not Specified	No numerical limit	Title V	State Permit Files
NA	0430041-009	5/9/2008	MN	Corn Plus	Fluidized Bed Boiler	Lime Injection and Sodium Bicarbonate Injection	Not Specified	0.16 lb/MMBtu	BACT-PSD	State Permit Files
NA	PSD-TX-1061	6/29/1905	TX	Nacogdoches Power Electric Generating Plant	Fluidized Bed Biomass Boiler	Inherent scrubbing from calcium in the fuel	Not Specified	0.046 lb/MMBtu	BACT-PSD	State Permit Files
AL-0223	705-0014-X015	7/14/2006	AL	Smurfit Stone Container Corp - Stevenson Mill	No. 2 Wood Fired Boiler	No Control	*No Control*	*Not specified in lb/MMBtu*	BACT-PSD	RBLC Clearinghouse
ND-0022	PTC06004	5/1/2006	ND	Archer Daniels Midland Company - Northam Su n	Wood/Hull Fired Boiler	No Control	No Control	0.47 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
WA-0327	PSD-05-04	1/25/2006	WA	Sierra Pacific Industries - Skagit County Lumber Mill	Bark/Wood Waste Fired Cogeneration Boiler	No Control	No Control	0.025 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
NA	2676-095-0071-V-01-8	10/24/2007	GA	The Procter & Gamble Paper Products Company	216 MMBtu/hr Biomass Boiler	No Control	No Control	0.025 lb/MMBtu (biomass)	Title V	State Permit Files

Table E-19

Recent BACT/Permit Decisions - SO2 from Emergency Engines

RBLC ID	Permit No.	Date	State	Owner/Facility	Process	Control Technology	Control Efficiency	Emission Limit	Basis	Source
MT-0022	3182-00	7/21/2003	MT	Bull Mountain Dev Company - Roundup Power Project	Emergency Generator	0.05% Sulfur Fuel, Limited to 200 hr/yr	97.7%	97.7% reduction based on hourly operational limit	BACT-PSD	RBLC Clearinghouse
PA-0257	17-313-001	5/7/2007	PA	Sunnyside Ethanol, LLC	Emergency Generators	Fuel Sulfur Limit of 0.05%	Not Specified	0.166 g/Bhp-hr	BACT-PSD	RBLC Clearinghouse
LA-0224	PSD-LA-726	3/20/2008	LA	Southwest Electric Power Company - Arsenal Hill Power Plant	Diesel Fire Pump	Low Sulfur Fuel, Limit Operating Hours, Proper Engine Maintenance	Not Specified	Not specified in g/Bhp-hr or lb/hp-hr	BACT-PSD	RBLC Clearinghouse
MN-0070	06100067-001	9/7/2007	MN	Minnesota Steel Industries, LLC	Diesel Fire Water Pump	0.05% Sulfur Fuel; 500 hr/yr	Not Specified	No numerical limit	BACT-PSD	RBLC Clearinghouse
LA-0192	PSD-LA-704	6/6/2005	LA	Crescent City Power	Diesel Fire Water Pump	Good Engine Design and Proper Operating Practices	Not Specified	0.65 g/bhp-hr	BACT-PSD	RBLC Clearinghouse
OH-0252	07-00503	12/28/2004	OH	Duke Energy Hanging Rock	Fire Water Pump	Low Sulfur Fuel	Not Specified	0.16 g/bhp-hr	BACT-PSD	RBLC Clearinghouse
OH-0252	07-00503	12/28/2004	OH	Duke Energy Hanging Rock	Back-up Generators	Low Sulfur Fuel	Not Specified	0.18 g/bhb-hr	BACT-PSD	RBLC Clearinghouse
WI-0228	04-RV-248	10/19/2004	WI	Wisconsin Public Service - Weston Plant	Diesel Booster Pump	0.003% Sulfur Fuel, Good Combustion Practices	Not Specified	Not specified in g/Bhp-hr or lb/hp-hr	BACT-PSD	RBLC Clearinghouse
WI-0228	04-RV-248	10/19/2004	WI	Wisconsin Public Service - Weston Plant	Main Fire Pump	0.003% Sulfur Fuel, Good Combustion Prectices	Not Specified	Not specified in g/Bhp-hr or lb/hp-hr	BACT-PSD	RBLC Clearinghouse
OH-0275	14-04682	8/24/2004	OH	Cinergy - PSI Energy - Madison Station	Emergency Diesel Fire Pump	0.05% Sulfur Fuel; 499 hr/hr operation	Not Specified	Not specified in g/Bhp-hr or lb/hp-hr	BACT-PSD	RBLC Clearinghouse
WV-0023	R14-0024	3/2/2004	WV	Longview Power, LLC - Maidsville	Fire Water Pump	0.05% Sulfur Fuel	Not Specified	Not specified in g/Bhp-hr or lb/hp-hr	BACT-PSD	RBLC Clearinghouse
CA-1073	418342	8/14/2003	CA	Los Angeles County Probation/FAC Planning/ISD	Fire Pump, Compression Ignition	0.0015% Sulfur Fuel, Limited to 200 hr/yr	Not Specified	No numerical limit	BACT-PSD	RBLC Clearinghouse
OH-0254	06-06792	8/14/2003	OH	Duke Energy Washington County LLC	Emergency Diesel Fire Pump Engine	Low Sulfur Fuel, Combustion Control	Not Specified	0.95 g/bhp-hr	BACT-PSD	RBLC Clearinghouse
IA-0067	Project 02-528	6/17/2003	IA	Midamerican Energy Company	Diesel Fire Pump	0.05% Sulfur Fuel, Good Combustion Practices	Not Specified	0.052 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
OK-0090	2001-157-C M-1 PSD	3/21/2003	OK	Duke Energy Stephens, LLC	Fire Water Pump	0.05% Sulfur Fuel	Not Specified	Not specified in g/Bhp-hr or lb/hp-hr	BACT-PSD	RBLC Clearinghouse
VA-0279	VA-21388	1/8/2003	VA	Cinergy Capital and Trading - Martinsville	Fire Water Pump	0.05% Sulfur Fuel	Not Specified	No numerical limit	BACT-PSD	RBLC Clearinghouse
WA-0291	EFSEC/2001-03	1/3/2003	WA	Wallula Generation, LLC - Wallula Power Plant	Diesel Fire Pump	0.05% Sulfur Fuel, Limited to 100 hr/yr	Not Specified	No numerical limit	Other	RBLC Clearinghouse
NA	0571321-001-AC	4/5/2006	FL	United States EnviroFuels, LLC - Port Sutton Ethanol Facility	Emergency Generator	0.5% Sulfur Fuel	Not Specified	No numerical limit	Minor Construction	State Permit Files
NA	0571321-001-AC	4/5/2006	FL	United States EnviroFuels, LLC - Port Sutton Ethanol Facility	Emergency Water Pump	0.5% Sulfur Fuel	Not Specified	No numerical limit	Minor Construction	State Permit Files
NC-0101	00986R1	9/29/2005	NC	Forsyth Energy Projects, LLC - Forsyth Energy Plant	Emergency Generator	No Control	No Control	Not specified in g/Bhp-hr or lb/hp-hr	BACT-PSD	RBLC Clearinghouse
NC-0101	00986R1	9/29/2005	NC	Forsyth Energy Projects, LLC - Forsyth Energy Plant	Emergency Firewater Pump	No Control	No Control	Not specified in g/Bhp-hr or lb/hp-hr	BACT-PSD	RBLC Clearinghouse

Table E-20

Recent BACT/Permit Decisions - CO from Biomass Boilers

RBLC ID	Permit No.	Date	State	Owner/Facility	Process	Control Technology	Control Efficiency	Emission Limit	Basis	Source
OH-0307	07-00534	4/4/2006	OH	Biomass Energy - South Point Biomass Generation	7 Wood Fired Boilers	Oxidation Catalyst	50%	0.1 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
OH-0269	07-00534	1/5/2004	OH	Biomass Energy, LLC - South Point Power	7 Wood Fired Boilers	Catalytic Oxidation	50%	0.1 lb/MMBtu	Other	RBLC Clearinghouse
MN-0074	13900114	8/23/2007	MN	Koda Energy	Biomass Boiler 4	Good Combustion Practices	Not Specified	0.43 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
WA-0335	PSD-06-02	5/22/2007	WA	Simpson Paper Company - Simpson Tacoma Kraft Company, LLC	Wood Waste Boiler	Overfire Air	Not Specified	0.35 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
ND-0022	PTC06004	5/1/2006	ND	Archer Daniels Midland Company - Northern Su n	Wood/Hull Fired Boiler	Good Combustion Practices	Not Specified	0.63 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
WA-0337	PSD-01-07 Amendment 1	2/1/2006	WA	Boise Cascade Corp - Boise White Paper, LLC	Wood/Bark Boilers	Overfire Air	Not Specified	500 ppm	Other	RBLC Clearinghouse
WA-0329	PSD-03-04	2/11/2005	WA	Darrington Energy Cogeneration Power Plant	Wood Waste Fired Boiler	Good Combustion Practices	Not Specified	0.35 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
LA-0188	PSD-LA-698	11/23/2004	LA	Inland Paperboard and Packaging - Bogalusa Mill	No. 12 Hogged Fuel Boiler (Bark)	Overfire Air, Good Combustion Practices	Not Specified	0.6 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
NH-0013	TP-B-0501	10/25/2004	NH	Public Service of New Hampshire - Schiller Station	Circulating Fluidized Bed Wood Fired Boiler No. 5	Good Combustion Practices with Fluidized Bed Design	Not Specified	0.1 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
GA-0114	2631-115-0021-V-01-4	10/13/2004	GA	Inland Paperboard and Packaging - Rome Linerboard Mill	Solid Fuel Boiler (Bark)	Staged Combustion and Good Combustion Practices	Not Specified	368 ppm @ 3% O2	BACT-PSD	RBLC Clearinghouse
FL-0257	PSD-FL-333	11/18/2003	FL	U.S. Sugar Corporation - Clewiston Sugar Mill & Refinery	Bagasse External Combustion	Good Combustion and Operating Practices	Not Specified	0.38 lb/MMBtu	Other	RBLC Clearinghouse
LA-0178	PSD-LA-77(M-2)	11/14/2003	LA	Boise Cascade Corp - Deridder Paper Mill	Wood Fired Boiler (Bark)	Good Equipment Design and Proper Combustion Techniques	Not Specified	0.33 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
AR-0072	1714-AOP-R3	2/28/2003	AR	Del-Tin Fiber, LLC	Heat Energy System - Wood Waste	Good Combustion Practices	Not Specified	0.78 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
LA-0218	PSD-LA-716	7/18/2007	LA	Boise Building Solutions Manufacturing, LLC - Florien Plywood Plant	Hogged Fuel Fired Boiler (wood)	High Pressure Overfire Air, Good Combustion	Not Specified	0.6 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
MN-0058	13700028-005	6/30/2005	MN	City of Virginia Department of Public Utilities	Wood Fired Boiler	Good Combustion	Not Specified	0.3 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
MN-0059	13700027-003	6/30/2005	MN	Hibbing Public Utilities	Wood Fired Boiler	Good Combustion	Not Specified	0.3 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
FL-0322	0510032-001-AC	12/23/2010	FL	Southeast Renewable Fuels (SRF), LLC	Biomass Boiler	Good Combustion	Not Specified	0.10 lb/MMBtu (30-day rolling)	BACT-PSD	State Permit Files
NA	0550063-001-AC	9/23/2011	FL	Highlands EnviroFuels (HEF), LLC	Biomass Boiler	Good Combustion	Not Specified	0.30 lb/MMBtu (30-day rolling)	BACT-PSD	State Permit Files
NA	4911-119-0025-E-03-0	7/29/2008	GA	Earth Resources, Inc. - Plant Carl	400 MMBtu/hr Bubbling Fluidized Bed Biomass Boiler	Oxidation Catalyst	Not Specified	0.149 lb/MMBtu	Title V; PSD Avoidance	State Permit Files
NA	4911-061-0001-P-01-0	5/15/2009	GA	Yellow Pine Energy Company, LLC	1,529 MMBtu/hr Fluidized Bed Biomass Boilers	Combustion Controls	Not Specified	0.30 lb/MMBtu	PSD Application	State Permit Files
NA	PSD-FL-333A	11/3/2004	FL	U.S. Sugar Corporation - Clewiston Sugar Mill & Refinery	Boiler No. 8 - Bagasse	Good Combustion Practices	Not Specified	No numerical limit	PSD Construc	State Permit Files
NA	PSD-TX-1061	2007	TX	Nacogdoches Power Electric Generating Plant	Fluidized Bed Biomass Boiler	Good combustion	Not Specified	0.15 lb/MMBtu	BACT-PSD	State Permit Files
WA-0327	PSD-05-04	1/25/2006	WA	Sierra Pacific Industries - Skagit County Lumber Mill	Bark/Wood Waste Fired Cogeneration Boiler	No Control	No Control	0.35 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
NA	4991-119-0025-E-02-0	10/31/2006	GA	Earth Resources, Inc. - Plant Carl	335 MMBtu/hr Bubbling Fluidized Bed Biomass Boiler	No Control	No Control	400 ppmdv7	Title V; PSD Avoidance	State Permit Files
NA	2676-095-0071-V-01-8	10/24/2007	GA	The Procter & Gamble Paper Products Company	216 MMBtu/hr Biomass Boiler	No Control	No Control	0.5 lb/MMBtu (biomass); 0.0363 lb/MMBtu (oil)	Title V	State Permit Files
NA	0430041-009	5/9/2008	MN	Corn Plus	Fluidized Bed Boiler	No Control	No Control	100 ppmdv or 90% destruction	BACT-PSD	State Permit Files

Table E-21

Recent BACT/Permit Decisions - CO from Natural Gas Boilers (10-100 MMBtu/hr)

RBLC ID	Permit No.	Date	State	Owner/Facility	Process	Control Technology	Control Efficiency	Emission Limit	Basis	Source
FL-0285	PSD-FL-381 AND 1030011-010-AC	01/26/07	FL	Progress Bartow Power Plant	Auxiliary Boiler - Natural Gas	Not specified	Not Specified	0.02 lb/MMBtu	BACT-PSD	State Permit Files
VA-0308	NA	01/14/08	VA	Warren County Facility	Auxiliary Boiler - Natural Gas	Not specified	Not Specified	0.036 lb/MMBtu	NA	RBLC Clearinghouse
MD-0040	CPCN CASE NO. 9129	2/27/09	MD	CPV St. Charles	Auxiliary Boiler - Natural Gas	Not specified	Not Specified	0.02 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
LA-0240	PSD-LA-747/1280-00141-V0	11/12/08	LA	Flopam Inc.	Natural Gas Fired Boilers	Good combustion practices	Not Specified	0.037 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
FL-0286	PSD-FL-354 AND 0990646-001-AC	06/14/10	FL	FPL West County Energy Center	Auxiliary Boiler - Natural Gas	Not specified	Not Specified	0.08 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
NV-0044	NA	8/20/09	NV	Harrah's Operating Company, Inc.	Natural Gas Fired Boilers	Good combustion practices	Not Specified	0.036 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
OH-0323	03-17392	6/5/08	OH	Titan Tire Corporation of Bryan	Natural Gas Fired Boilers	Not specified	Not Specified	0.08 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
OH-0309	04-01358	5/3/07	OH	Toledo Supplier Park Paint Shop	Natural Gas Fired Boilers	Not specified	Not Specified	0.08 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
AL-0230	503-0095-X001 thru X026	8/17/07	AL	Thyssenkrup Steel and Stainless USA, LLC	Natural Gas Fired Boilers	Not specified	Not Specified	0.04 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
LA-0246	PSD-LA-619(M6)	12/31/10	LA	St. Charles Refinery	Natural Gas Fired Boilers	Good combustion practices	Not Specified	0.08 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
MN-0070	06100067-001	9/7/07	MN	Minnesota Steel Industries, LLC	Natural Gas Fired Boilers	Not specified	Not Specified	0.08 lb/MMBtu	BACT-PSD	RBLC Clearinghouse

Table E-22

Recent BACT/Permit Decisions - CO from Emergency Engines

RBLC ID	Permit No.	Date	State	Owner/Facility	Process	Control Technology	Control Efficiency	Emission Limit	Basis	Source
MT-0022	3182-00	7/21/2003	MT	Bull Mountain Dev Company - Roundup Power Project	Emergency Generator	Limited to 200 hr/yr	97.7%	97.7% reduction based on hourly operational limit	BACT-PSD	RBLC Clearinghouse
LA-0224	PSD-LA-726	3/20/2008	LA	Southwest Electric Power Company - Arsenal Hill Power Plant	Diesel Fire Pump	Low Sulfur Fuel, Limit Operating Hours, Proper Engine Maintenance	Not Specified	Not specified in g/Bhp-hr or lb/hp-hr	BACT-PSD	RBLC Clearinghouse
CA-1144	SE 02-01	4/25/2007	CA	Caithness Blythe II, LLC - Blythe Energy Project II	Fire Pump	0.05% Sulfur Fuel	Not Specified	Not specified in g/Bhp-hr or lb/hp-hr	BACT-PSD	RBLC Clearinghouse
OK-0100	2004-198-TV	10/21/2005	IA	Dalitalia, LLC - Muskogee Porcelain Floor Tile Pit	Emergency Generators	Good Combustion	Not Specified	35.6 g/bhp-hr	Other	RBLC Clearinghouse
OK-0111	2004-198-C (M-1)	10/14/2005	OK	Dalitalia, LLC - Muskogee Porcelain Floor Tile Pit	Emergency Generators	Good Combustion	Not Specified	0.0067 lb/hp-hr	BACT-PSD	RBLC Clearinghouse
LA-0192	PSD-LA-704	6/6/2005	LA	Crescent City Power	Diesel Fire Water Pump	Good Engine Design and Proper Operating Practices	Not Specified	2.01 g/bhp-hr	BACT-PSD	RBLC Clearinghouse
LA-0194	PSD-LA-703	11/24/2004	LA	Sabine Pass LNG Import Terminal	Firewater Booster Pump Diesel Engines	Good Engine Design, Proper Operating Practices	Not Specified	0.27 g/bhp-hr	BACT-PSD	RBLC Clearinghouse
WI-0228	04-RV-248	10/19/2004	WI	Wisconsin Public Service - Weston Plant	Diesel Booster Pump	0.003% Sulfur Fuel, Good Combustion Practices	Not Specified	Not specified in g/Bhp-hr or lb/hp-hr	BACT-PSD	RBLC Clearinghouse
WI-0228	04-RV-248	10/19/2004	WI	Wisconsin Public Service - Weston Plant	Main Fire Pump	0.003% Sulfur Fuel, Good Combustion Practices	Not Specified	Not specified in g/Bhp-hr or lb/hp-hr	BACT-PSD	RBLC Clearinghouse
WV-0023	R14-0024	3/2/2004	WV	Longview Power, LLC - Maidsville	Fire Water Pump	Good Combustion Practices	Not Specified	23.6 g/bhp-hr	BACT-PSD	RBLC Clearinghouse
AK-0059	307CP01	9/29/2003	AK	USAF Eareckson Air Station	Fire Water Pump	Good Combustion Practices	Not Specified	No numerical limit	BACT-PSD	RBLC Clearinghouse
CA-1073	418342	8/14/2003	CA	Los Angeles County Probation/FAC Planning/ISD	Fire Pump, Compression Ignition	Operation Limited to 200 hr/yr	Not Specified	0.44 g/bhp-hr	BACT-PSD	RBLC Clearinghouse
OH-0254	06-06792	8/14/2003	OH	Duke Energy Washington County LLC	Emergency Diesel Fire Pump Engine	Low Sulfur Fuel, Combustion Control	Not Specified	1 g/bhp-hr	BACT-PSD	RBLC Clearinghouse
IA-0067	Project 02-528	6/17/2003	IA	Midamerican Energy Company	Diesel Fire Pump	Good Combustion Practices	Not Specified	0.95 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
OK-0090	2001-157-C M-1 PSD	3/21/2003	OK	Duke Energy Stephens, LLC	Fire Water Pump	Engine Design and Good Combustion Practices	Not Specified	1.09 g/bhp-hr	BACT-PSD	RBLC Clearinghouse
NA	4911-149-0008-E-01-0	6/10/2008	GA	Greenway Renewable Power, LLC	1500 kW Biodiesel Emergency Generator	200 hr/yr (100 hr/yr non-emergency time); 0.05% Sulfur Fuel (0.0015% after 10/1/10)	Not Specified	2.6 g/np-hr	Title V; PSD Avoidance	State Permit Files
PA-0257	17-313-001	5/7/2007	PA	Sunnyside Ethanol, LLC	Emergency Generators	No Control	No Control	0.29 g/BHp-hr	BACT-PSD	RBLC Clearinghouse
NC-0101	00986R1	9/29/2005	NC	Forsyth Energy Projects, LLC - Forsyth Energy Plant	Emergency Generator	No Control	No Control	2.05 g/bhp-hr	BACT-PSD	RBLC Clearinghouse
NC-0101	00986R1	9/29/2005	NC	Forsyth Energy Projects, LLC - Forsyth Energy Plant	Emergency Firewater Pump	No Control	No Control	2.05 g/bhp-hr	BACT-PSD	RBLC Clearinghouse
OH-0252	07-00503	12/28/2004	OH	Duke Energy Hanging Rock	Fire Water Pump	No Control	No Control	3 g/bhp-hr	BACT-PSD	RBLC Clearinghouse
OH-0252	07-00503	12/28/2004	OH	Duke Energy Hanging Rock	Back-up Generators	No Control	No Control	8.5 g/bhp-hr	BACT-PSD	RBLC Clearinghouse
OH-0275	14-04682	8/24/2004	OH	Cinergy - PSI Energy - Madison Station	Emergency Diesel Fire Pump	No Control	No Control	Not specified in g/Bhp-hr or lb/hp-hr	BACT-PSD	RBLC Clearinghouse

Table E-23

Recent BACT/Permit Decisions - CO2

RBLC ID	Permit No.	Date	State	Owner/Facility	Process	Control Technology	Control Efficiency	Emission Limit	Basis	Source
*FL-0330	DPA-EPA-R4001	12/1/2011	FL	Port Dolphin Energy LLC	Natural Gas Fired Boilers (278 MMBtu/hr)	Natural gas and good combustion practices	Not Specified	117 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
*FL-0330	DPA-EPA-R4001	12/1/2011	FL	Port Dolphin Energy LLC	Power Generating Engines (Gas Fired)	Natural gas and good combustion practices	Not Specified	181 g/kWh	BACT-PSD	RBLC Clearinghouse
*VT-0037	AP-11-015	2/10/2012	VT	Beaver Wood Energy Fair Haven	Wood Fired Boiler (482 MMBtu/hr)	Energy efficiency and good combustion practices	Not Specified	2993 lb/MWh (30-day avg)	BACT-PSD	RBLC Clearinghouse
IA-0101	78-A-019-P10	1/12/2012	IA	Ottumwa Generating Station	Coal Fired Boiler (8669 MMBtu/hr)	Good combustion practices	Not Specified	2927 lb/MWh (30-day avg)	BACT-PSD	RBLC Clearinghouse
LA-0254	PSD-LA-752	8/16/2011	LA	Ninemile Point Electric Generating Plant	Natural Gas Fired Aux Boiler (338 MMBtu/hr)	Good combustion practices	Not Specified	117 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
LA-0254	PSD-LA-752	8/16/2011	LA	Ninemile Point Electric Generating Plant	Emergency Diesel Engines	Good combustion practices	Not Specified	163 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
LA-0256	PSD-LA-754	12/6/2011	LA	Cogeneration Plant	Cogeneration (475 MMBtu/hr)	Natural gas and good combustion practices	Not Specified	117 lb/MMBtu	BACT-PSD	RBLC Clearinghouse
LA-0256	PSD-LA-754	12/6/2011	LA	Cogeneration Plant	Emergency Engine (Natural Gas)	Natural gas and good combustion practices	Not Specified	0.83 lb/hp-hr	BACT-PSD	RBLC Clearinghouse
LA-0257	PSD-LA-703(M3)	12/6/2011	LA	Sabine Pass LNG Terminal	Combined Cycle Refrigeration Compressor Turbines	Natural gas and good combustion practices	Not Specified	No short term BACT rate provided	BACT-PSD	RBLC Clearinghouse
LA-0257	PSD-LA-703(M3)	12/6/2011	LA	Sabine Pass LNG Terminal	Generator Engines (2)	Natural gas and good combustion practices	Not Specified	No short term BACT rate provided	BACT-PSD	RBLC Clearinghouse
LA-0257	PSD-LA-703(M3)	12/6/2011	LA	Sabine Pass LNG Terminal	Marine Flare	Natural gas and good combustion practices	Not Specified	No short term BACT rate provided	BACT-PSD	RBLC Clearinghouse
LA-0257	PSD-LA-703(M3)	12/6/2011	LA	Sabine Pass LNG Terminal	Simple Cycle Generation Turbines (2)	Natural gas and good combustion practices	Not Specified	No short term BACT rate provided	BACT-PSD	RBLC Clearinghouse
LA-0257	PSD-LA-703(M3)	12/6/2011	LA	Sabine Pass LNG Terminal	Simple Cycle Refrigeration Compressor Turbines	Natural gas and good combustion practices	Not Specified	No short term BACT rate provided	BACT-PSD	RBLC Clearinghouse
LA-0257	PSD-LA-703(M3)	12/6/2011	LA	Sabine Pass LNG Terminal	Wet/Dry Gas Flares (4)	Natural gas and good combustion practices	Not Specified	No short term BACT rate provided	BACT-PSD	RBLC Clearinghouse
NA	NA	9/16/2011	KS	Abengoa Bioenergy Biomass of Kansas, LLC	Biomass Fired Boiler	Biomass primary fuel, energy efficiency & good combustion practices	Not Specified	0.34 lb CO2e / lb steam (30-day avg.)	BACT-PSD	State Permit Files
NA	NA	9/16/2011	KS	Abengoa Bioenergy Biomass of Kansas, LLC	Fermentation	Process efficiency, energy efficiency, water recycling & co-product use	Not Specified	5.89 lb CO2e / gal ethanol (30-day avg.)	BACT-PSD	State Permit Files
NA	NA	9/16/2011	KS	Abengoa Bioenergy Biomass of Kansas, LLC	Biogas Flare	Biogas and natural gas as sole fuels with efficient operation	Not Specified	20,166 tpy CO2e	BACT-PSD	State Permit Files
NA	NA	9/16/2011	KS	Abengoa Bioenergy Biomass of Kansas, LLC	Fire Pump Engine	Fuel-efficient NFPA-20 certified firewater pump engine	Not Specified	24.0 tpy CO2e	BACT-PSD	State Permit Files

APPENDIX F

Dispersion Modeling Files

BPIPPRM Files

AERMAP Files

AERMOD Files

Dispersion modeling inputs and results have been provided on CD-ROM formatted for IBM-compatible personal computers. The directory structure on the CD-ROM is self-explanatory, with inputs and outputs organized by the program used. An index of the files provided follows.

BPIPPRM (04274)

BPIPPRM is automatically run by AERMODview with each model run. So BPIPPRM files are provided in each of the model folders:

filename	Contents
*.BPI	Input file
*.PRO	Output file
*.SUP	Summary output file
*_BPIP.LOG	BPIP Log output file

AERMAP (11103)

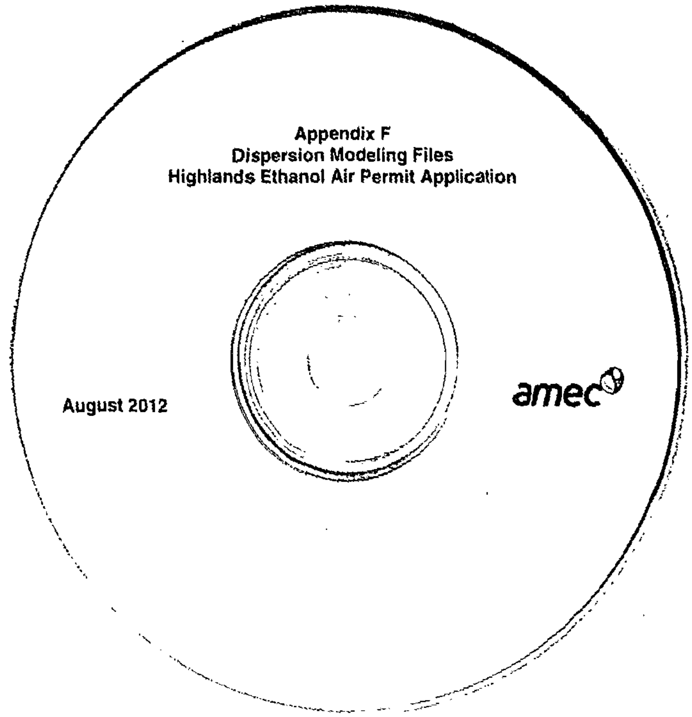
The AERMAP files are provided in each of the model run folders. The filenames use extensions that are common to all files. These are as follows:

filename	Contents
*.API	Input file – Full Receptor Grid and All Sources
*.ROU	Receptor Input File
*.SOU	Source Input File
*.AST	Detailed output file – Full Receptor Grid and All Sources

AERMOD (12060)

The AERMOD files are provided in the AERMOD folder. The filenames use extensions that are common to all files. These are as follows:

filename	Contents
HLetohPPP_XXXf.ADI	SIA Input File (PPP = pollutant, XXX = optional averaging flag)
HLetohPPP_XXXf.ADO	SIA Output File (PPP = pollutant, XXX = optional averaging flag)
HLetohPPP_XXXf.SUM	SIA Summary File (PPP = pollutant, XXX = optional averaging flag)
HLetohPPPi_XXXf.ADI	Interactive Input File (PPP = pollutant, XXX = optional averaging flag)
HLetohPPPi_XXXf.ADO	Interactive Output File (PPP = pollutant, XXX = optional averaging flag)
HLetohPPPi_XXXf.SUM	Interactive Summary File (PPP = pollutant, XXX = optional averaging flag)


Appendix F
Dispersion Modeling Files
Highlands Ethanol Air Permit Application
August 2012
amec

APPENDIX G
Interactive Source Data

20D Screening Method for Identifying Interactive Sources

Facility	UTME	UTMN	distance (D) from project (km)	SO2 facility total (tpy)	PM facility total (tpy)	NOx facility total (tpy)	$Q_{SO2}/20D$	$Q_{PM10}/20D$	$Q_{NO2}/20D$
85000118 FLORIDA POWER & LIGHT (PMR)	542680	2992650	53.5	78,480	2,616	40,757	**73.3**	**2.44**	**38.09**
5500184 TAMPA ELECTRIC COMPANY	464300	3035400	36.5	4,046	17	5,016	**5.54**	0.02	**6.87**
51000331 U.S. SUGAR CORP. CLEWISTON MILL	506100	2956900	57.7	3,194	344	3,215	**2.77**	0.30	**2.8**
8501027 INDIANTOWN COGENERATION, L.P.	547650	2990700	58.8	2,633	340	2,882	**2.20**	0.29	**2.45**
5500034 FLORIDA POWER CORPORATION D/B/A PROGRESS	451400	3050500	56.1	5,055	0	54	**4.51**	0.00	0.05
9301046 OKEECHOBEE LANDFILL, INC.	530280	3023960	38.5	1,393	20	160	**1.81**	0.03	0.21
5500143 BETTER ROADS, INC.	465600	3008700	28.0	167	46	146	0.30	0.08	0.26
51001526 SOUTHERN GARDENS CITRUS PROCESSING CORP.	487500	2957600	55.9	186	116	199	0.17	0.10	0.18
5500052 GEORGIA PACIFIC CORRUGATED LLC	466980	3009230	26.6	193	18	16	0.36	0.03	0.03
8501476 FLORIDIAN NATURAL GAS STORAGE CO., INC.	545930	2996330	55.3	4	0	271	0.00	0.00	0.24
9300011 OKEECHOBEE ASPHALT & READY-MIX CONCRETE,	516090	3014210	22.8	105	0	1	0.23	0.00	0.00
4300031 STANDARD SAND AND SILICA CO.	470600	2965300	53.0	88	134	18	0.08	0.13	0.02
5100222 FIBERSTAR, INC.	487690	2957660	55.8	0	249	0	0.00	0.22	0.00
4300081 ATLAS-TRANSOIL INC	489200	2966600	46.8	85	19	63	0.09	0.02	0.07
5100271 AMERIMIX INDUSTRIES, INC.	495410	2957290	55.9	164	0	11	0.15	0.00	0.01
4300183 OLDCASTLE LAWN AND GARDEN, INC.	492040	2961340	51.9	18	1	132	0.02	0.00	0.13
5500462 HIGHLANDS COUNTY DEPT.OF SOLID WASTE	469330	3042850	38.1	10	34	63	0.01	0.04	0.08
55003211 TURF CARE SUPPLY CORP.	469500	3038400	34.7	0	20	57	0.00	0.03	0.08
77751721 BETTER ROADS, INC.	491967	2966190	47.0	20	0	74	0.02	0.00	0.08
9301092 BP TECHNOLOGY INC	525180	3017400	32.2	16	0	48	0.02	0.00	0.07
5500123 APAC-SOUTHEAST INC., CENTRAL FL DIVISION	451130	3050000	56.0	6	27	64	0.01	0.02	0.06
8500025 LOUIS DREYFUS CITRUS, INC.	547980	2991470	58.9	0	52	47	0.00	0.04	0.04
85001214 BAY STATE MILLING CO	547400	2991680	58.2	0	84	0	0.00	0.07	0.00
10502554 AVON PARK CORRECTIONAL INSTITUTE	464600	3059300	54.3	32	0	24	0.03	0.00	0.02
5500581 GULFSTREAM NATURAL GAS SYSTEM, L.L.C.	472570	3041740	35.3	0	0	29	0.00	0.00	0.04
11101071 TREASURE COAST LAND CLEARING	545570	3035410	56.8	15	0	26	0.01	0.00	0.02
11101091 PORT ST. LUCIE TRACTOR SERVICES, INC.	532010	3037290	45.6	6	0	23	0.01	0.00	0.02
77700733 APAC-SOUTHEAST INC., CENTRAL FL DIVISION	334300	3085600	174.7	5	26	73	0.00	0.01	0.02
11100723 FLORIDA ROCK INDUSTRIES, INC.	547460	3013460	54.2	0	2	14	0.00	0.00	0.01
8501412 GULFSTREAM NATURAL GAS SYSTEM, L.L.C.	543830	2993140	54.4	0	1	9	0.00	0.00	0.01
8501361 PERKINS TRUCKING, INC.	534900	3002000	43.1	2	0	6	0.00	0.00	0.01
5500222 FOUNTAIN FUNERAL HOME	449000	3052800	59.4	1	0	1	0.00	0.00	0.00
5500491 E-STONE USA CORPORATION	455500	3042170	47.6	0	0	1	0.00	0.00	0.00
55000613 GENPAK LLC	464790	3036830	37	0	1	0	0.00	0.00	0.00
5500171 CEMEX CONSTRUCTION MATERIALS FLORIDA LLC	458000	3035000	41.5	0	1	0	0.00	0.00	0.00
5500331 CEMEX CONSTRUCTION MATERIALS FLORIDA LLC	450350	3054660	59.7	0	1	0	0.00	0.00	0.00
4300071 CEMEX CONSTRUCTION MATERIALS FLORIDA LLC	489180	2966740	46.6	0	1	0	0.00	0.00	0.00
5500261 SEBRING SEPTIC TANK & PRECAST CO	463300	3034200	36.6	0	0	0	0.00	0.00	0.00
5500161 JAHNA CONCRETE, INC.	450100	3054300	59.6	0	0	0	0.00	0.00	0.00
9301004 OKEECHOBEE ASPHALT& READY MIX CONCRETE	515950	3014210	22.8	0	0	0	0.00	0.00	0.00

20D Screening Method for Identifying Interactive Sources

Facility	UTME	UTMN	distance (D) from project (km)	SO2 facility total (tpy)	PM facility total (tpy)	NOx facility total (tpy)	Q_{SO2}/20D	Q_{PM10}/20D	Q_{NO2}/20D
5500211 JAHNA CONCRETE, INC.	462500	3034400	37.4	0	0	0	0.00	0.00	0.00
5500081 JAHNA CONCRETE INC	463500	3019200	30.4	0	0	0	0.00	0.00	0.00
5500241 HIGHLANDS CREMATORY, INC.	450700	3052800	58.2	0	0	0	0.00	0.00	0.00
5500271 WELLCRAFT MARINE CORP	448800	3052300	59.2	0	0	0	0.00	0.00	0.00
9300071 TARMAC FLORIDA	516990	3014060	23.7	0	0	0	0.00	0.00	0.00
5100071 HARE LUMBER & READY-MIX INC	506620	2958270	56.5	0	0	0	0.00	0.00	0.00
9301021 BUXTON FUNERAL HOME, INC.	516770	3013720	23.5	0	0	0	0.00	0.00	0.00
9301121 OKEECHOBEE CREMATORY, LLC	516810	3013430	23.5	0	0	0	0.00	0.00	0.00
9301083 TWIN OAKS PET CEMETARY	517270	3043720	38.8	0	0	0	0.00	0.00	0.00
11101101 TREASURE COAST TRACTOR SERVICE, INC.	545120	3035240	56.3	0	0	0	0.00	0.00	0.00
8501051 TAMPA FARM SERVICE, INC.	547160	2992020	57.9	0	0	0	0.00	0.00	0.00

Note: bold values - facility to be included in interactive modeling per the "20D" screening results exceeding 1.0

FPL Martin Power Plant Interactive Source Data

Facility ID	EU ID	Pollutant	Owner	Site Name	Status	UTM Zone	UTM East(km)	UTM North(km)	Lat DD	Lat MM	Lat SS	Long DD
850001	1	NOX	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80
850001	2	NOX	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80
850001	3	NOX	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80
850001	4	NOX	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80
850001	5	NOX	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80
850001	6	NOX	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80
850001	7	NOX	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80
850001	9	NOX	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80
850001	11	NOX	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80
850001	12	NOX	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80
850001	17	NOX	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80
850001	18	NOX	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80
850001	3	PM10	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80
850001	4	PM10	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80
850001	5	PM10	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80
850001	6	PM10	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80
850001	11	PM10	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80
850001	12	PM10	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80
850001	17	PM10	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80
850001	18	PM10	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80
850001	19	PM10	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80
850001	1	SO2	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80
850001	2	SO2	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80
850001	3	SO2	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80
850001	4	SO2	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80
850001	5	SO2	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80
850001	6	SO2	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80
850001	7	SO2	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80
850001	9	SO2	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80
850001	11	SO2	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80
850001	12	SO2	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80
850001	17	SO2	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80
850001	18	SO2	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	A	17	542.68	2992.65	27	3	25	80

FPL Martin Power Plant Interactive Source Data

Facility ID	EU ID	Pollutant	Long MM	Long SS	Facility Type Code	Description	EU Description	EU Status
850001	1	NOX	33	55	1	STEAM ELECTRIC PLANT	*Fossil Fuel Fired Steam Generator #1(Acid Rain, Phase II)*	A
850001	2	NOX	33	55	1	STEAM ELECTRIC PLANT	Fossil Fuel Fired Steam Generator #2(Acid Rain, Phase II)	A
850001	3	NOX	33	55	1	STEAM ELECTRIC PLANT	Combustion Turbine with HRSG (CT 3A)(Acid Rain, Phase II)	A
850001	4	NOX	33	55	1	STEAM ELECTRIC PLANT	Combustion Turbine with HRSG (CT 3B)(Acid Rain, Phase II)	A
850001	5	NOX	33	55	1	STEAM ELECTRIC PLANT	Combustion Turbine with HRSG (CT 4A)(Acid Rain, Phase II)	A
850001	6	NOX	33	55	1	STEAM ELECTRIC PLANT	Combustion Turbine with HRSG (CT 4B)(Acid Rain, Phase II)	A
850001	7	NOX	33	55	1	STEAM ELECTRIC PLANT	Auxiliary Boiler	A
850001	9	NOX	33	55	1	STEAM ELECTRIC PLANT	Diesel Generator(0.718 MW for Units 003-006)	A
850001	11	NOX	33	55	1	STEAM ELECTRIC PLANT	Unit 8A - 170 MW gas turbine with gas-fired HRSG	A
850001	12	NOX	33	55	1	STEAM ELECTRIC PLANT	Unit 8B - 170 MW gas turbine with gas-fired HRSG	A
850001	17	NOX	33	55	1	STEAM ELECTRIC PLANT	Unit 8C - 170 MW gas turbine with gas-fired HRSG	A
850001	18	NOX	33	55	1	STEAM ELECTRIC PLANT	Unit 8D - 170 MW gas turbine with gas-fired HRSG	A
850001	3	PM10	33	55	1	STEAM ELECTRIC PLANT	Combustion Turbine with HRSG (CT 3A)(Acid Rain, Phase II)	A
850001	4	PM10	33	55	1	STEAM ELECTRIC PLANT	Combustion Turbine with HRSG (CT 3B)(Acid Rain, Phase II)	A
850001	5	PM10	33	55	1	STEAM ELECTRIC PLANT	Combustion Turbine with HRSG (CT 4A)(Acid Rain, Phase II)	A
850001	6	PM10	33	55	1	STEAM ELECTRIC PLANT	Combustion Turbine with HRSG (CT 4B)(Acid Rain, Phase II)	A
850001	11	PM10	33	55	1	STEAM ELECTRIC PLANT	Unit 8A - 170 MW gas turbine with gas-fired HRSG	A
850001	12	PM10	33	55	1	STEAM ELECTRIC PLANT	Unit 8B - 170 MW gas turbine with gas-fired HRSG	A
850001	17	PM10	33	55	1	STEAM ELECTRIC PLANT	Unit 8C - 170 MW gas turbine with gas-fired HRSG	A
850001	18	PM10	33	55	1	STEAM ELECTRIC PLANT	Unit 8D - 170 MW gas turbine with gas-fired HRSG	A
850001	19	PM10	33	55	1	STEAM ELECTRIC PLANT	Cooling tower	A
850001	1	SO2	33	55	1	STEAM ELECTRIC PLANT	Fossil Fuel Fired Steam Generator #1(Acid Rain, Phase II)	A
850001	2	SO2	33	55	1	STEAM ELECTRIC PLANT	Fossil Fuel Fired Steam Generator #2(Acid Rain, Phase II)	A
850001	3	SO2	33	55	1	STEAM ELECTRIC PLANT	Combustion Turbine with HRSG (CT 3A)(Acid Rain, Phase II)	A
850001	4	SO2	33	55	1	STEAM ELECTRIC PLANT	Combustion Turbine with HRSG (CT 3B)(Acid Rain, Phase II)	A
850001	5	SO2	33	55	1	STEAM ELECTRIC PLANT	Combustion Turbine with HRSG (CT 4A)(Acid Rain, Phase II)	A
850001	6	SO2	33	55	1	STEAM ELECTRIC PLANT	Combustion Turbine with HRSG (CT 4B)(Acid Rain, Phase II)	A
850001	7	SO2	33	55	1	STEAM ELECTRIC PLANT	Auxiliary Boiler	A
850001	9	SO2	33	55	1	STEAM ELECTRIC PLANT	Diesel Generator(0.718 MW for Units 003-006)	A
850001	11	SO2	33	55	1	STEAM ELECTRIC PLANT	Unit 8A - 170 MW gas turbine with gas-fired HRSG	A
850001	12	SO2	33	55	1	STEAM ELECTRIC PLANT	Unit 8B - 170 MW gas turbine with gas-fired HRSG	A
850001	17	SO2	33	55	1	STEAM ELECTRIC PLANT	Unit 8C - 170 MW gas turbine with gas-fired HRSG	A
850001	18	SO2	33	55	1	STEAM ELECTRIC PLANT	Unit 8D - 170 MW gas turbine with gas-fired HRSG	A

FPL Martin Power Plant Interactive Source Data

Facility ID	EU ID	Pollutant	Stack Height(ft)	Diam(ft)	Exit Temp(F)	ACFM	DSCFM	VEL(ft/s)	Potential(lb/hr)	Potential(tpy)	Allowable(lb/hr)	Allowable(tpy)
850001	1	NOX	499	36	338	2634519		43.1	2595	11366.1	1808	7919
850001	2	NOX	499	36	338	2634519		43.1	2595	11366.1	2595	11366
850001	3	NOX	213	20	280	2420307		128.4	461	3108	461	3108
850001	4	NOX	213	20	280	2420307		128.4	461	3108	177	3108
850001	5	NOX	213	20	280	2420307		128.4	461	3108	461	3108
850001	6	NOX	213	20	280	2420307		128.4	461	3108	461	3108
850001	7	NOX	60	3.6	490	30536		50	4.88	21.37	4.88	21.37
850001	9	NOX	13	0.5	810	4750		403.2	72.07	316	72.07	316
850001	11	NOX	120	19	202	1004200	800000	59	23.6	103	66	111.87
850001	12	NOX	120	19	202	1004200	800000	59	23.6	103	66	111.87
850001	17	NOX	120	19	202	1004200	800000	59	23.6	103	95.3	3
850001	18	NOX	120	19	202	1004200	800000	59	23.6	103	23.6	34
850001	3	PM10	213	20	280	2420307		128.4	60.6	100	18	100
850001	4	PM10	213	20	280	2420307		128.4	60.6	100	60.6	100
850001	5	PM10	213	20	280	2420307		128.4	60.6	100	18	100
850001	6	PM10	213	20	280	2420307		128.4	60.6	100	60.6	100
850001	11	PM10	120	19	202	1004200	800000	59	37	63		
850001	12	PM10	120	19	202	1004200	800000	59	37	63		
850001	17	PM10	120	19	202	1004200	800000	59	37	63		
850001	18	PM10	120	19	202	1004200	800000	59	37	63		
850001	19	PM10	45	38	90	1386055		20.4	4.65	20.4		
850001	1	SO2	499	36	338	2634519		43.1	6920	30309.6	6920	30309
850001	2	SO2	499	36	338	2634519		43.1	6920	30309.6	6920	30309
850001	3	SO2	213	20	280	2420307		128.4	920	568	920	568
850001	4	SO2	213	20	280	2420307		128.4	920	568	920	568
850001	5	SO2	213	20	280	2420307		128.4	920	568	91.5	568
850001	6	SO2	213	20	280	2420307		128.4	920	568	91.5	568
850001	7	SO2	60	3.6	490	30536		50	0.0098	0.043		
850001	9	SO2	13	0.5	810	4750		403.2	1.72	7.5		
850001	11	SO2	120	19	202	1004200	800000	59	99	70	99	25
850001	12	SO2	120	19	202	1004200	800000	59	99	70	4.9	8.31
850001	17	SO2	120	19	202	1004200	800000	59	99	70	99	25
850001	18	SO2	120	19	202	1004200	800000	59	99	70	9.8	47

Facility ID	EU ID	Pollutant	Comments	Actual(tpy)
850001	1	NOX	While burning natural gas	1579.94896
850001	2	NOX	While burning fuel oil. Co-firing of NG and FO shall be prorated see permit ccondition QA10.	1901.536955
850001	3	NOX	While burning fuel oil. TYP represent the total allowed for fuel oil and natural gas. Basis for allowable: PSD-FL-146.	187.704
850001	4	NOX	While burning natural gas. TYP represent the total allowed for fuel oil and natural gas. Basis for allowable: PSD-FL-146	219.609
850001	5	NOX	While burning fuel oil. TYP represent the total allowed for fuel oil and natural gas. Basis for allowable: PSD-FL-146	181.459
850001	6	NOX	While burning fuel oil. TYP represent the total allowed for fuel oil and natural gas. Basis for allowable: PSD-FL-146	167.013
850001	7	NOX	While burning natural gas and fuel oil. Basis for allowable: PSD-FL-146	0.015037
850001	9	NOX	Basis for allowable: PSD-FL-146. Equivalent emission is from the permit application calculation data.	1.23216
850001	11	NOX	Not Active - Replaced. Gas Firing (Normal). Annual emissions based on compressor inlet temperature of 59deg F and 3390 hr/yr	42.93278
850001	12	NOX	Not Active - Replaced. Gas Firing (Normal). Annual emissions based on compressor inlet temperature of 59deg F and 3390 hr/yr	52.25662
850001	17	NOX	Gas firing, simple cycle (1000 hr/yr) w/peaking (60 hr/yr)	46.929425
850001	18	NOX	Gas firing, combined cycle w/duct burning (2880 hr/yr)	39.0379
850001	3	PM10	While burning natural gas. TYP represent the total allowed for fuel oil and natural gas. Basis for allowable: PSD-FL-146	10.7784
850001	4	PM10	While burning fuel oil. TYP represent the total allowed for fuel oil and natural gas. Basis for allowable: PSD-FL-146	10.6704
850001	5	PM10	While burning natural gas. TYP represent the total allowed for fuel oil and natural gas. Basis for allowable: PSD-FL-146	10.8446
850001	6	PM10	While burning fuel oil. TYP represent the total allowed for fuel oil and natural gas. Basis for allowable: PSD-FL-146	9.9819
850001	11	PM10		9.71259
850001	12	PM10		7.55424
850001	17	PM10		11.1945
850001	18	PM10		11.4075
850001	19	PM10		10
850001	1	SO2	Lbs/hr is for 100% oil firing.	4726.845404
850001	2	SO2	Lbs/hr is for 100% oil firing.	5300.221267
850001	3	SO2	While burning fuel oil. TYP represent the total allowed for fuel oil and natural gas. Basis for allowable: PSD-FL-146	3.4
850001	4	SO2	While burning fuel oil. TYP represent the total allowed for fuel oil and natural gas. Basis for allowable: PSD-FL-146	3.5
850001	5	SO2	While burning natural gas. TYP represent the total allowed for fuel oil and natural gas. Basis for allowable: PSD-FL-146	3.5
850001	6	SO2	While burning natural gas. TYP represent the total allowed for fuel oil and natural gas. Basis for allowable: PSD-FL-146	3.3
850001	7	SO2	Basis for allowable: PSD-FL-146. Compliance testing for firing fuel oil shall be conducted once per day.	0.000031
850001	9	SO2	Basis for allowable: PSD-FL-164	0.080988
850001	11	SO2	Oil firing (500 hr/yr)	3.432652
850001	12	SO2	Gas Firing (1 gr/100 SCF of NG). Equivalent emissions based on compressor inlet temperature of 59¿ F and 3390 hr/yr of gas firing	3.913694
850001	17	SO2	Oil firing (500 hr/yr)	3.573414
850001	18	SO2	Gas firing (2 gr/100 SCF of NG)	3.650683

FPL Martin Power Plant Interactive Source Data

Facility ID	EU ID	Pollutant	Year	ICE_PM	ICE_SO2	ICE_NO2	Baseline PM(lb/hr)	Baseline PM(ton/yr)	Baseline SO2(lb/hr)	Baseline SO2(ton/yr)	Baseline NO2(ton/yr)
850001	1	NOX	2007	C	C	E	865	3788.7	6920	30309.6	11366.1
850001	2	NOX	2007	C	C	E	865	3788.7	6920	30309.6	11366.1
850001	3	NOX	2007	C	C	C					
850001	4	NOX	2007	C	C	C					
850001	5	NOX	2007	C	C	C					
850001	6	NOX	2007	C	C	C					
850001	7	NOX	2007	C	C	C					
850001	9	NOX	2007								
850001	11	NOX	2007	C	C	C					
850001	12	NOX	2007	C	C	C					
850001	17	NOX	2007								
850001	18	NOX	2007								
850001	3	PM10	2007	C	C	C					
850001	4	PM10	2007	C	C	C					
850001	5	PM10	2007	C	C	C					
850001	6	PM10	2007	C	C	C					
850001	11	PM10	2007	C	C	C					
850001	12	PM10	2007	C	C	C					
850001	17	PM10	2007								
850001	18	PM10	2007								
850001	19	PM10	2007								
850001	1	SO2	2007	C	C	E	865	3788.7	6920	30309.6	11366.1
850001	2	SO2	2007	C	C	E	865	3788.7	6920	30309.6	11366.1
850001	3	SO2	2007	C	C	C					
850001	4	SO2	2007	C	C	C					
850001	5	SO2	2007	C	C	C					
850001	6	SO2	2007	C	C	C					
850001	7	SO2	2007	C	C	C					
850001	9	SO2	2007								
850001	11	SO2	2007	C	C	C					
850001	12	SO2	2007	C	C	C					
850001	17	SO2	2007								
850001	18	SO2	2007								

US Sugar - Clewiston Interactive Source Data

Facility ID	EU ID	Pollutant	Owner	Site Name	Status	UTM Zone	UTM East(km)	UTM North(km)	Lat DD
510003	1	NOX	U.S. SUGAR CORP. CLEWISTON MILL	U.S. SUGAR CLEWISTON MILL AND REFINERY	A	17	506.1	2956.9	26
510003	2	NOX	U.S. SUGAR CORP. CLEWISTON MILL	U.S. SUGAR CLEWISTON MILL AND REFINERY	A	17	506.1	2956.9	26
510003	3	NOX	U.S. SUGAR CORP. CLEWISTON MILL	U.S. SUGAR CLEWISTON MILL AND REFINERY	A	17	506.1	2956.9	26
510003	4	NOX	U.S. SUGAR CORP. CLEWISTON MILL	U.S. SUGAR CLEWISTON MILL AND REFINERY	A	17	506.1	2956.9	26
510003	5	NOX	U.S. SUGAR CORP. CLEWISTON MILL	U.S. SUGAR CLEWISTON MILL AND REFINERY	A	17	506.1	2956.9	26
510003	9	NOX	U.S. SUGAR CORP. CLEWISTON MILL	U.S. SUGAR CLEWISTON MILL AND REFINERY	A	17	506.1	2956.9	26
510003	12	NOX	U.S. SUGAR CORP. CLEWISTON MILL	U.S. SUGAR CLEWISTON MILL AND REFINERY	A	17	506.1	2956.9	26
510003	13	NOX	U.S. SUGAR CORP. CLEWISTON MILL	U.S. SUGAR CLEWISTON MILL AND REFINERY	A	17	506.1	2956.9	26
510003	14	NOX	U.S. SUGAR CORP. CLEWISTON MILL	U.S. SUGAR CLEWISTON MILL AND REFINERY	A	17	506.1	2956.9	26
510003	17	NOX	U.S. SUGAR CORP. CLEWISTON MILL	U.S. SUGAR CLEWISTON MILL AND REFINERY	A	17	506.1	2956.9	26
510003	28	NOX	U.S. SUGAR CORP. CLEWISTON MILL	U.S. SUGAR CLEWISTON MILL AND REFINERY	A	17	506.1	2956.9	26
510003	35	NOX	U.S. SUGAR CORP. CLEWISTON MILL	U.S. SUGAR CLEWISTON MILL AND REFINERY	A	17	506.1	2956.9	26
510003	1	SO2	U.S. SUGAR CORP. CLEWISTON MILL	U.S. SUGAR CLEWISTON MILL AND REFINERY	A	17	506.1	2956.9	26
510003	2	SO2	U.S. SUGAR CORP. CLEWISTON MILL	U.S. SUGAR CLEWISTON MILL AND REFINERY	A	17	506.1	2956.9	26
510003	3	SO2	U.S. SUGAR CORP. CLEWISTON MILL	U.S. SUGAR CLEWISTON MILL AND REFINERY	A	17	506.1	2956.9	26
510003	9	SO2	U.S. SUGAR CORP. CLEWISTON MILL	U.S. SUGAR CLEWISTON MILL AND REFINERY	A	17	506.1	2956.9	26
510003	12	SO2	U.S. SUGAR CORP. CLEWISTON MILL	U.S. SUGAR CLEWISTON MILL AND REFINERY	A	17	506.1	2956.9	26
510003	13	SO2	U.S. SUGAR CORP. CLEWISTON MILL	U.S. SUGAR CLEWISTON MILL AND REFINERY	A	17	506.1	2956.9	26
510003	14	SO2	U.S. SUGAR CORP. CLEWISTON MILL	U.S. SUGAR CLEWISTON MILL AND REFINERY	A	17	506.1	2956.9	26
510003	17	SO2	U.S. SUGAR CORP. CLEWISTON MILL	U.S. SUGAR CLEWISTON MILL AND REFINERY	A	17	506.1	2956.9	26
510003	28	SO2	U.S. SUGAR CORP. CLEWISTON MILL	U.S. SUGAR CLEWISTON MILL AND REFINERY	A	17	506.1	2956.9	26
510003	35	SO2	U.S. SUGAR CORP. CLEWISTON MILL	U.S. SUGAR CLEWISTON MILL AND REFINERY	A	17	506.1	2956.9	26

US Sugar - Clewiston Interactive Source Data

Facility ID	EU ID	Pollutant	Lat MM	Lat SS	Long DD	Long MM	Long SS	Facility Type Code	Description
510003	1	NOX	44	6	80	56	19	12	SUGAR PROCESSING PLANT
510003	2	NOX	44	6	80	56	19	12	SUGAR PROCESSING PLANT
510003	3	NOX	44	6	80	56	19	12	SUGAR PROCESSING PLANT
510003	4	NOX	44	6	80	56	19	12	SUGAR PROCESSING PLANT
510003	5	NOX	44	6	80	56	19	12	SUGAR PROCESSING PLANT
510003	9	NOX	44	6	80	56	19	12	SUGAR PROCESSING PLANT
510003	12	NOX	44	6	80	56	19	12	SUGAR PROCESSING PLANT
510003	13	NOX	44	6	80	56	19	12	SUGAR PROCESSING PLANT
510003	14	NOX	44	6	80	56	19	12	SUGAR PROCESSING PLANT
510003	17	NOX	44	6	80	56	19	12	SUGAR PROCESSING PLANT
510003	28	NOX	44	6	80	56	19	12	SUGAR PROCESSING PLANT
510003	35	NOX	44	6	80	56	19	12	SUGAR PROCESSING PLANT
510003	1	SO2	44	6	80	56	19	12	SUGAR PROCESSING PLANT
510003	2	SO2	44	6	80	56	19	12	SUGAR PROCESSING PLANT
510003	3	SO2	44	6	80	56	19	12	SUGAR PROCESSING PLANT
510003	9	SO2	44	6	80	56	19	12	SUGAR PROCESSING PLANT
510003	12	SO2	44	6	80	56	19	12	SUGAR PROCESSING PLANT
510003	13	SO2	44	6	80	56	19	12	SUGAR PROCESSING PLANT
510003	14	SO2	44	6	80	56	19	12	SUGAR PROCESSING PLANT
510003	17	SO2	44	6	80	56	19	12	SUGAR PROCESSING PLANT
510003	28	SO2	44	6	80	56	19	12	SUGAR PROCESSING PLANT
510003	35	SO2	44	6	80	56	19	12	SUGAR PROCESSING PLANT

US Sugar - Clewiston Interactive Source Data

Facility ID	EU ID	Pollutant	EU Description	EU Status	Stack Height(ft)	Diam(ft)	Exit Temp(F)	ACFM	DSCFM
510003	1	NOX	Boiler 1 - 255,000 lb/hr steam rate (1-hr max.)	A	213	6.1	160	140135	
510003	2	NOX	Boiler 2 - 230,000 lb/hr steam rate (1-hr max.)	A	213	6.1	160	153937	
510003	3	NOX	Boiler 3 - 130,000 lb/hr steam rate (1-hr max.)	I	213	7.5	155	122393	
510003	4	NOX	BOILER #5 WITH SCRUBBER.	I	65	6	146	59500	
510003	5	NOX	BOILER #6 WITH SCRUBBER.	I	65	6	154	57503	
510003	9	NOX	Boiler 4 - 300,000 lb/hr steam rate (1-hr max.)	A	150	8.2	160	281000	
510003	12	NOX	DIESEL ELECTRIC GENERATOR #1. GENERAL MOTORS MODEL 16-567-CE	I	37	1.2	475	2721	1383
510003	13	NOX	DIESEL GENERATOR #2. GENERAL MOTORS MODEL #16-567-B	I	37	1.2	475	2721	1383
510003	14	NOX	Boiler 7 - 385,000 lb/hr steam rate (1-hr max.)	A	225	5		254587	
510003	17	NOX	Granular carbon regeneration furnace	A	30	2	160	4300	2746
510003	28	NOX	Boiler 8 - Bagasse boiler rated at 500,000 lb/hour steam	A	199	13	330	400000	225000
510003	35	NOX	Refinery package boiler, 12 MMBtu/hour, 300 hp	C	20	1	350	3770	
510003	1	SO2	Boiler 1 - 255,000 lb/hr steam rate (1-hr max.)	A	213	6.1	160	140135	
510003	2	SO2	Boiler 2 - 230,000 lb/hr steam rate (1-hr max.)	A	213	6.1	160	153937	
510003	3	SO2	Boiler 3 - 130,000 lb/hr steam rate (1-hr max.)	I	213	7.5	155	122393	
510003	9	SO2	Boiler 4 - 300,000 lb/hr steam rate (1-hr max.)	A	150	8.2	160	281000	
510003	12	SO2	DIESEL ELECTRIC GENERATOR #1. GENERAL MOTORS MODEL 16-567-CE	I	37	1.2	475	2721	1383
510003	13	SO2	DIESEL GENERATOR #2. GENERAL MOTORS MODEL #16-567-B	I	37	1.2	475	2721	1383
510003	14	SO2	Boiler 7 - 385,000 lb/hr steam rate (1-hr max.)	A	225	5		254587	
510003	17	SO2	Granular carbon regeneration furnace	A	30	2	160	4300	2746
510003	28	SO2	Boiler 8 - Bagasse boiler rated at 500,000 lb/hour steam	A	199	13	330	400000	225000
510003	35	SO2	Refinery package boiler, 12 MMBtu/hour, 300 hp	C	20	1	350	3770	

US Sugar - Clewiston Interactive Source Data

Facility ID	EU ID	Pollutant	VEL(ft/s)	Potential(lb/hr)	Potential(tpy)	Allowable(lb/hr)	Allowable(tpy)	Comments	Actual(tpy)	Year
510003	1	NOX	79		222				19.9	2007
510003	2	NOX	87		222				21.47	2007
510003	3	NOX	46		144.2				11.16	2005
510003	4	NOX	35	21	37.8				7.4	1997
510003	5	NOX	33		75.6				13.5	1997
510003	9	NOX	88.7	126.6	288	126.6	288	Annual test concurrently with CO test	57.39	2007
510003	12	NOX	40	34.9	152.9				2	2004
510003	13	NOX	40	34.9	152.9				4.02	2003
510003	14	NOX	216.1	185	809	185	809		214.59	2007
510003	17	NOX	22.8	3	13.14				12.1	2007
510003	28	NOX	50.2	131	473.7	131	473.7	Limit is 0.14 lb/MMBtu, 30 day rolling average	294	2007
510003	35	NOX	80	1.71	0.64					
510003	1	SO2	79	164.8	296	164.8	296		0.16	2007
510003	2	SO2	87	164.8	296	164.8	296		0.12	2007
510003	3	SO2	46	143	257	143	257		3.59	2005
510003	9	SO2	88.7	38	86.2	38	86.4	Limit is for bagasse firing only	0.31	2007
510003	12	SO2	40	5.8	25.4	5.8	25.4		0.33	2004
510003	13	SO2	40	5.8	25.4	5.8	25.4		0.33	2004
510003	14	SO2	216.1	125	550	125	550		69.63	2007
510003	17	SO2	22.8	0.7	3.07	0.7	3.07	Each fuel purchase must comply with 0.05% sulfur limit	1.02	2007
510003	28	SO2	50.2	56.2	203	56.2	203	Test within 90-100% of 24-hour steam production limit	75.36	2007
510003	35	SO2	80	0.61	0.23					

US Sugar - Clewiston Interactive Source Data

Facility ID	EU ID	Pollutant	ICE_PM	ICE_SO2	ICE_NO2	Baseline PM(lb/hr)	Baseline PM(ton/yr)	Baseline SO2(lb/hr)	Baseline SO2(ton/yr)	Baseline NO2(ton/yr)
510003	1	NOX								
510003	2	NOX								
510003	3	NOX								
510003	4	NOX								
510003	5	NOX								
510003	9	NOX	C	C	C					
510003	12	NOX								
510003	13	NOX								
510003	14	NOX								
510003	17	NOX								
510003	28	NOX								
510003	35	NOX								
510003	1	SO2								
510003	2	SO2								
510003	3	SO2								
510003	9	SO2	C	C	C					
510003	12	SO2								
510003	13	SO2								
510003	14	SO2								
510003	17	SO2								
510003	28	SO2								
510003	35	SO2								

Progress Energy - Avon Park Interactive Source Data

Facility ID	EU ID	Pollutant	Owner	Site Name	Status	UTM Zone	UTM East(km)	UTM North(km)	Lat DD	Lat MM	Lat SS
550003	3	SO2	FLORIDA POWER CORPORATION D/B/A PROGRESS	AVON PARK	A	17	451.4	3050.5	27	34	45
550003	4	SO2	FLORIDA POWER CORPORATION D/B/A PROGRESS	AVON PARK	A	17	451.4	3050.5	27	34	45

Progress Energy - Avon Park Interactive Source Data

Facility ID	EU ID	Pollutant	Long DD	Long MM	Long SS	Facility Type Code	Description	EU Description	EU Status	Stack Height(ft)	Diam(ft)
550003	3	SO2	81	29	33	1	STEAM ELECTRIC PLANT	Gas Turbine Peaking Unit No. 1	A	55	10
550003	4	SO2	81	29	33	1	STEAM ELECTRIC PLANT	Gas Turbine Peaking Unit No. 2	A	55	10

Progress Energy - Avon Park Interactive Source Data

Facility ID	EU ID	Pollutant	Exit Temp(F)	ACFM	DSCFM	VEL(ft/s)	Potential(lb/hr)	Potential(tpy)	Allowable(lb/hr)	Allowable(tpy)
550003	3	SO2	850	2000000		424	577	2527	577	2527
550003	4	SO2	850	2000000		424.4	577	2527	577	2527

Progress Energy - Avon Park Interactive Source Data

Facility ID	EU ID	Pollutant	Comments	Actual(tpy)	Year	ICE_PM	ICE_SO2	ICE_NO2
550003	3	SO2	Basis for allowable emission is AO 28-202500. Sulfur content limit is not federally enforceable.	1.076	2007			
550003	4	SO2	Basis for allowable emission is AO 28-202500. Sulfur content limit is not federally enforceable.	6.361	2007			

Progress Energy - Avon Park Interactive Source Data

Facility ID	EU ID	Pollutant	Baseline PM(lb/hr)	Baseline PM(ton/yr)	Baseline SO2(lb/hr)	Baseline SO2(ton/yr)	Baseline NO2(ton/yr)
550003	3	SO2					
550003	4	SO2					

TECO Phillips Station Interactive Source Data

Facility ID	EU ID	Pollutant	Owner	Site Name	Status	UTM Zone	UTM East(km)	UTM North(km)	Lat DD	Lat MM	Lat SS	Long DD	Long MM
550018	1	NOX	TAMPA ELECTRIC COMPANY	PHILLIPS STATION	A	17	464.3	3035.4	27	26	35	81	21
550018	2	NOX	TAMPA ELECTRIC COMPANY	PHILLIPS STATION	A	17	464.3	3035.4	27	26	35	81	21
550018	4	NOX	TAMPA ELECTRIC COMPANY	PHILLIPS STATION	A	17	464.3	3035.4	27	26	35	81	21
550018	1	SO2	TAMPA ELECTRIC COMPANY	PHILLIPS STATION	A	17	464.3	3035.4	27	26	35	81	21
550018	2	SO2	TAMPA ELECTRIC COMPANY	PHILLIPS STATION	A	17	464.3	3035.4	27	26	35	81	21
550018	4	SO2	TAMPA ELECTRIC COMPANY	PHILLIPS STATION	A	17	464.3	3035.4	27	26	35	81	21

TECO Phillips Station Interactive Source Data

Facility ID	EU ID	Pollutant	Long SS	Facility Type Code	Description	EU Description	EU Status
550018	1	NOX	54	2	OTHER ELECTRIC PRODUCTION	19.535 MW SLOW SPEED DIESEL GENERATING UNIT 1	A
550018	2	NOX	54	2	OTHER ELECTRIC PRODUCTION	19.535 MW SLOW SPEED DIESEL GENERATING UNIT 2	A
550018	4	NOX	54	2	OTHER ELECTRIC PRODUCTION	AUXILIARY STEAM BOILER	A
550018	1	SO2	54	2	OTHER ELECTRIC PRODUCTION	19.535 MW SLOW SPEED DIESEL GENERATING UNIT 1	A
550018	2	SO2	54	2	OTHER ELECTRIC PRODUCTION	19.535 MW SLOW SPEED DIESEL GENERATING UNIT 2	A
550018	4	SO2	54	2	OTHER ELECTRIC PRODUCTION	AUXILIARY STEAM BOILER	A

TECO Phillips Station Interactive Source Data

Facility ID	EU ID	Pollutant	Stack Height(ft)	Diam(ft)	Exit Temp(F)	ACFM	DSCFM	VEL(ft/s)	Potential(lb/hr)	Potential(tpy)	Allowable(lb/hr)	Allowable(tpy)	Comments
550018	1	NOX	150	6	335	134500		79	571.8	2504.5	571.8	2504.5	
550018	2	NOX	150	6	350	135500		79	571.82	2504.5	571.82	2504.5	
550018	4	NOX	62	2.2					1.49	6.526			
550018	1	SO2	150	6	335	134500		79	459.29	2011.5	459.29	2011.5	
550018	2	SO2	150	6	350	135500		79	459.29	2011.5	459.29	2011.5	
550018	4	SO2	62	2.2					5.26	22.8	5.26	22.8	

TECO Phillips Station Interactive Source Data

Facility ID	EU ID	Pollutant	Actual(tpy)	Year	ICE_PM	ICE_SO2	ICE_NO2	Baseline PM(lb/hr)	Baseline PM(ton/yr)	Baseline SO2(lb/hr)	Baseline SO2(ton/yr)
550018	1	NOX	309.2669	2007							
550018	2	NOX	303.6832	2007							
550018	4	NOX	0.50364	2007							
550018	1	SO2	198.662715	2007							
550018	2	SO2	202.547492	2007							
550018	4	SO2	0.091906	2007							

TECO Phillips Station Interactive Source Data

Facility ID	EU ID	Pollutant	Baseline NO2(ton/yr)
550018	1	NOX	
550018	2	NOX	
550018	4	NOX	
550018	1	SO2	
550018	2	SO2	
550018	4	SO2	

Indiantown Cogeneration Plant Interactive Source Data

Facility ID	EU ID	Pollutant	Owner	Site Name	Status	UTM Zone	UTM East(km)	UTM North(km)	Lat DD	Lat MM
850102	1	NOX	INDIANTOWN COGENERATION, L.P.	INDIANTOWN COGENERATION PLANT	A	17	547.65	2990.7	27	2
850102	3	NOX	INDIANTOWN COGENERATION, L.P.	INDIANTOWN COGENERATION PLANT	A	17	547.65	2990.7	27	2
850102	1	SO2	INDIANTOWN COGENERATION, L.P.	INDIANTOWN COGENERATION PLANT	A	17	547.65	2990.7	27	2
850102	3	SO2	INDIANTOWN COGENERATION, L.P.	INDIANTOWN COGENERATION PLANT	A	17	547.65	2990.7	27	2

Indiantown Cogeneration Plant Interactive Source Data

Facility ID	EU ID	Pollutant	Lat SS	Long DD	Long MM	Long SS	Facility Type Code	Description	EU Description	EU Status
850102	1	NOX	21	80	30	53	1	STEAM ELECTRIC PLANT	Pulverized Coal Main Boiler	A
850102	3	NOX	21	80	30	53	1	STEAM ELECTRIC PLANT	(2) Auxiliary Boilers and Temporary Auxiliary Boiler	I
850102	1	SO2	21	80	30	53	1	STEAM ELECTRIC PLANT	Pulverized Coal Main Boiler	A
850102	3	SO2	21	80	30	53	1	STEAM ELECTRIC PLANT	(2) Auxiliary Boilers and Temporary Auxiliary Boiler	I

Indiantown Cogeneration Plant Interactive Source Data

Facility ID	EU ID	Pollutant	Stack Height(ft)	Diam(ft)	Exit Temp(F)	ACFM	DSCFM	VEL(ft/s)	Potential(lb/hr)	Potential(tpy)	Allowable(lb/hr)	Allowable(tpy)
850102	1	NOX	495	16	140	1123700		93.2	582	2549	582	2549
850102	3	NOX	210	5	350	103200		87.6	71.6	177	68	34
850102	1	SO2	495	16	140	1123700		93.2	582	2549		
850102	3	SO2	210	5	350	103200		87.6	18	16.91	18	9

Indiantown Cogeneration Plant Interactive Source Data

Facility ID	EU ID	Pollutant	Comments	Actual(tpy)	Year	ICE_PM
850102	1	NOX	Basis for allowable emission: PSD-FL-168. Emission limit based on 24 hr daily block average (midnight to midnight).	1949.967	2007	C
850102	3	NOX	0.2 lb/mmBtu applies all the time. Basis for allowable emissions: PSD-FL-168	2.22	2006	C
850102	1	SO2	70 percent reduction; 30-day rolling average basis.	2068.78	2007	C
850102	3	SO2	While firing fuel oil. Basis for allowable emissions: PSD-FL-168	0.013	2006	C

Indiantown Cogeneration Plant Interactive Source Data

Facility ID	EU ID	Pollutant	ICE_SO2	ICE_NO2	Baseline PM(lb/hr)	Baseline PM(ton/yr)	Baseline SO2(lb/hr)	Baseline SO2(ton/yr)	Baseline NO2(ton/yr)
850102	1	NOX	C	C	0	0	0	0	0
850102	3	NOX	C	C	0	0	0	0	0
850102	1	SO2	C	C	0	0	0	0	0
850102	3	SO2	C	C	0	0	0	0	0

Okeechobee Landfill Interactive Source Data

Facility ID	EU ID	Pollutant	Owner	Site Name	Status	UTM Zone	UTM East(km)	UTM North(km)	Lat DD	Lat MM	Lat SS	Long DD
930104	3	SO2	OKEECHOBEE LANDFILL, INC.	BERMAN ROAD LANDFILL	A	17	530.28	3023.96	27	20	24	80

Okeechobee Landfill Interactive Source Data

Facility ID	EU ID	Pollutant	Long MM	Long SS	Facility Type Code	Description	EU Description
930104	3	SO2	41	27	39	MUNICIPAL SOLID WASTE LANDFILL	3000 SCFM ENC FLARE, MODEL 1776 EVAP 3016

Okeechobee Landfill Interactive Source Data

Facility ID	EU ID	Pollutant	EU Status	Stack Height(ft)	Diam(ft)	Exit Temp(F)	ACFM	DSCFM	VEL(ft/s)	Potential(lb/hr)	Potential(tpy)	Allowable(lb/hr)	Allowable(tpy)	Comments
930104	3	SO2	A	50	11	1500	185060	46714	32.5	1.51	6.6			

Okeechobee Landfill Interactive Source Data

Facility ID	EU ID	Pollutant	Actual(tpy)	Year	ICE_PM	ICE_SO2	ICE_NO2	Baseline PM(lb/hr)	Baseline PM(ton/yr)	Baseline SO2(lb/hr)	Baseline SO2(ton/yr)
930104	3	SO2	379	2007							

Facility ID	EU ID	Pollutant	Baseline NO2(ton/yr)
930104	3	SO2	

APPENDIX H
Exempt and Insignificant Emission Units

APPENDIX H
Exempt Emission Units Pursuant to FDEP Form No. 62-210.900(1), Section II.C.

Final design of the facility and equipment is not yet complete. Therefore, a specific list of exempt equipment is not available at this time. However, the following types of exempt equipment may be included in the final facility design.

- Space Heaters – Exempt per 62-210.300(3)(a)(9) F.A.C.: Equipment used exclusively for space heating, other than boilers;
- Laboratory Equipment – Exempt per 62-210.300(3)(a)(12) F.A.C.: Laboratory equipment used exclusively for chemical or physical analyses.
- Maintenance Soldering and Welding – Exempt per 62-210.300(3)(a)(13) F.A.C.: Brazing, soldering or welding equipment.
- Fire suppression systems and fire extinguishers – Exempt per 62-210.300(3)(a)(15) F.A.C.: Fire and safety equipment.
- Lubrication of miscellaneous equipment – Exempt per 62-210.300(3)(a)(16) F.A.C.: Petroleum lubrication systems.
- Use of pesticides, herbicides and/or fungicides inside or outside of the facility – Exempt per 62-210.300(3)(a)(17) F.A.C.: Application of fungicide, herbicide, or pesticide.
- Maintenance cold cleaners – Exempt per 62-210.300(3)(a)(23) F.A.C.: Degreasing units using heavier-than-air vapors exclusively, provided that such units shall not use any substance containing any hazardous air pollutant; or 62-210.300(3)(a)(24) F.A.C.: Nonhalogenated solvent storage and cleaning operations, provided that such operations shall not use any solvent containing any hazardous air pollutant.
- Small boilers and hot water heaters – Exempt per 62-210.300(3)(a)(33) F.A.C.: Fossil fuel steam generators, hot water generators, and other external combustion heating units with collective heat input capacity equal to or less than 10 million Btu per hour, fired by natural gas or propane, and not subject to Acid Rain, CAIR, or unit-specific requirements.

Additional equipment units are expected to qualify as insignificant emission units. These include the miscellaneous bulk storage tanks described in Section 2.2.7:

- Sulfuric acid (93% solution),
- Magnesium hydroxide (61% solution),
- Corn syrup,
- Phosphoric acid (85% solution),
- Aqueous ammonia (19% solution),
- Flocculant solution, and
- Caustic soda (50% solution).

All of these tanks will be of a vertical fixed roof design.