TECHNICAL EVALUATION

&

PRELIMINARY DETERMINATION

APPLICANT

Harvest Power Orlando, LLC
221 Crescent Street, Suite 402
Waltham, Massachusetts 02453

Harvest Energy Garden - Orlando
ARMS Facility ID No. 0951340

PROJECT

Draft Permit No. PSD-FL-418
Project No. 0951340-001-AC

Biogas-to-Energy and Fertilizer Project

COUNTY

Orange County, Florida

PERMITTING AUTHORITY

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

May 30, 2012

1. GENERAL PROJECT INFORMATION

1.1. Facility Description and Location

Harvest Power, Inc. produces renewable energy and nutrient-rich soil, mulch and organic fertilizer products from organic material throughout North America in British Columbia, Ontario, California and throughout the Mid-Atlantic, Midwest states and Northeastern United States. Harvest Power, Inc., doing business as Harvest Energy Orlando, LLC, is proposing to construct a facility, Harvest Energy Garden – Orlando, adjacent to the Reedy Creek Wastewater Treatment Facility in Orange County at 2151 Bear Island Road in Lake Buena Vista, Florida. Harvest Energy Garden – Orlando intends to construct an anaerobic digester that is designed to produce biogas and fertilizer from the decomposition of organic material. The maximum design amount of wet organic material received by the facility will be from 162,560 tons/year (April 11th letter from McGuire Woods) to 301,900 tons/year (original application). All non-organic material will be shipped off site to a landfill. The biogas will be combusted in two nominal 1.6 megawatt (MW) reciprocating internal combustion engines/electrical generator sets to produce electricity for sale to the grid and to support the facility. A 1,200 standard cubic feet per minute (scfm) open utility flare will be used primarily as a backup control device to combust the biogas when the engines are unavailable or to control emissions when more biogas is generated than can be handled by the engines.

The facility will be an electrical services plant categorized under Standard Industrial Classification Code of SIC No. 4911. The facility will be located at 2151 Bear Island Road in Lake Buena Vista, Florida. The UTM coordinates are Zone 17, 442.10 kilometers (km) East and 3139.02 km North. This site is in an area that is in attainment (or designated as unclassifiable) for all air pollutants subject to Ambient Air Quality Standards (AAQS).

Figure 1: Proposed Location of Facility – Orlando **Figure 2: Aerial View of Proposed Location**

The nearest PSD Class I area is Chassahowitzka National Wildlife Refuge, which is approximately 110 km from the proposed new facility.

1.2. Project Description

On March 22, 2012, the Department received an application from Harvest Energy Orlando, LLC to construct and operate a biogas to energy and fertilizer facility. The facility will receive food waste, thickened wastewater activated sludge and similar organic waste materials. The organic waste materials will be digested and converted to fertilizer and biogas for electrical energy production. The project will be located on land leased from Reedy Creek Improvement District. Walt Disney World will provide much of the raw waste materials and purchase the electricity through its Reedy Creek Utilities. The facility will consist of five main sections: a feedstock receiving and pre-treatment process; an anaerobic digestion process; a biogas, power generation, and heat recovery process; an odor removal process; and a digestate management/fertilizer production process. Emission sources will include two 1.6 MW Caterpillar Model G3520C reciprocating internal combustion engine/electrical generator

sets, an backup open "candlestick-type" flare, and a bio-scrubber to control potential odor causing pollutants, hazardous air pollutants (HAP) and volatile organic compounds (VOC) emissions.

Waste feedstock entering the facility will undergo a pre-treatment process to remove contaminants, such as glass, metals, plastic, etc. All non-organic material will be shipped off site to a landfill. The waste feedstock will be turned into a slurry and then sent to two continuously stirred tank reactor digesters. The digesters will break down the organics in the slurry and convert them primarily into methane (CH_4) and carbon dioxide (CO_2). After the digestion process, the biogas will be passed through a biogas scrubber to remove hydrogen sulfide (H_2S) and a knockout tower to remove water prior to combustion in the engines. An open flare will be used primarily as a backup control device to combust the biogas when the engines are unavailable. The generator exhaust will be used to heat oil for use in an indirect-heated dryer. The generators will also be equipped with water jackets to heat water for use in the facility processes. The remaining solids will be centrifuged to remove water and then further dried in the indirect-heated dryer to produce a final fertilizer product.

This project consists of the following emissions units (EU).

EU No.	Description
001 - 002	Two nominal 1.6 MW Caterpillar Model G3520C lean-burn internal combustion engine/generator sets
003	Bio-Scrubber
004	Flare #1, a 1200 scfm open utility, candlestick-type flare

1.3. Primary Regulatory Categories

- The project will be a major source of hazardous air pollutants (HAP).
- The project will be a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C.
- The project includes no units subject to the acid rain provisions of the Clean Air Act.
- The project is subject to PSD preconstruction review in accordance with Rule 62-212.400, F.A.C.
- The project includes units subject to applicable New Source Performance Standards (NSPS) in Title 40, Part 60 of the Code of Federal Regulations.
- The project includes units subject to applicable National Emissions Standards for Hazardous Air Pollutants (NESHAP) in Title 40, Part 63 of the Code of Federal Regulations.

1.4. Processing Schedule

03/22/2012 Received the application for a minor source air pollution construction permit.

04/23/2012 Requested additional information.

05/10/2012 Received additional information; application complete.

2. APPLICABLE REGULATIONS

2.1. State Regulations

This project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Department of Environmental Protection to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). This project is subject to the applicable rules and regulations defined in the following Chapters of the F.A.C.: 62-4 (Permitting Requirements); 62-204 (Ambient Air Quality Requirements, PSD Increments, and Federal Regulations Adopted by Reference); 62-210 (Permits Required, Public Notice, Reports, Stack Height Policy, Circumvention, Excess Emissions, and Forms); 62-212 (Preconstruction Review, PSD Review and BACT, and Non-attainment Area Review); 62-213 (Title V Air Operation Permits for Major Sources of Air Pollution); 62-296 (Emission Limiting Standards); and 62-297 (Test Methods and Procedures, Continuous Monitoring Specifications, and Alternate Sampling Procedures). PSD

applicability and the preconstruction review requirements of Rule 62-212.400, F.A.C. along with other applicable state regulations are discussed in Sections 3 and 4 of this report, respectively.

2.2. Federal Regulations

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

3. PSD APPLICABILITY REVIEW

3.1. General PSD Applicability

The Department regulates major stationary sources in accordance with Florida's PSD program pursuant to Rule 62-212.400, F.A.C. PSD preconstruction review is required in areas that are currently in attainment with the state and federal Ambient Air Quality Standards (AAQS) or areas designated as "unclassifiable" for these regulated pollutants. PSD pollutants include: carbon monoxide (CO); nitrogen oxides (NO_X); sulfur dioxide (SO_2); particulate matter (PM); PM smaller than 10 micrometers (PM_{10}); VOC; lead (Pb); fluorides (F); sulfuric acid mist (SAM); total reduced sulfur (TRS), including H_2S; and several other pollutants specific to municipal waste combustors.

As defined in Rule 62-210.200(189)(a)1, F.A.C., a "major stationary source" (major PSD source) is any of 28 listed stationary sources of air pollutants which emits, or has the potential to emit, 100 tons per year (TPY) or more of any PSD pollutant. Link to Rule 62-210, F.A.C. The major stationary source threshold for source categories not on the cited list is 250 TPY or more of any PSD pollutant.

For major stationary sources, PSD applicability is based on emissions thresholds known as the significant emission rates as defined in Rule 62-210.200 (Definitions), F.A.C. For each PSD pollutant that exceeds the corresponding significant emission rate, BACT must be employed to control emissions and an air quality impact analysis must be conducted if the PSD pollutant has a defined AAQS. Significant emission rate also means any emissions rate or any net emissions increase of a PSD pollutant associated with a major stationary source or major modification which would construct within 10 kilometers of a Class I area and have an impact on such area equal to or greater than 1 gram per cubic meter, 24-hour average. Although a facility may be "major" for only one PSD pollutant, a project must include BACT controls for any PSD pollutant that exceeds the corresponding significant emission rates given in Table 1.

Table 1 - List of Significant Emission Rates by PSD-Pollutant [1, 4]

Pollutant	Significant Emission Rates (TPY)	Pollutant	Significant Emission Rates (TPY)
CO	100	NO_X	40
PM/PM_{10} [2]	25/15	Ozone (VOC) [3]	40
Ozone (NO_X) [3]	40	SAM	7
SO_2	40	F	3
Pb	0.6	TRS	10
H_2S	10	Hg	0.1

Notes:

1. Excludes those defined exclusively for municipal waste combustors and municipal solid waste landfills.
2. $PM_{2.5}$ is a PSD pollutant, but a significant emission rate has not yet been defined in the Department's rules. The Department is in the process of adopting the federal significant emission rate of 10 TPY. Refer to Link to

$PM_{2.5}$ Rule Development . Until the rule is finalized, projects in Florida are regulated by $PM_{2.5}$ precursors and surrogates (e.g. PM/PM_{10}, NH_3, SO_2 and NO_X).

3. Ozone (O_3) is regulated by its precursors (VOC and NO_X).
4. There is a federal significant emission rate of 75,000 TPY for greenhouse gases (GHG) as carbon dioxide equivalent (CO_{2e}) that has not been incorporated into Department rules. However, the applicability to the CO_2 component of GHG emissions from bioenergy and biogenic stationary sources was recently deferred by EPA until the second half of 2014. Refer to: Link to Final CO_2 PSD Deferral.

3.2. Project Subject to PSD Preconstruction Review

Because an existing major stationary source belonging to the same industrial grouping is located in proximity to the proposed Harvest Power facility,[1] the Department must consider whether state and federal law require it to treat the proposed facility as an expansion of the existing facility for purposes of PSD preconstruction review. Such evaluations are fact-dependant and made on case-by-case bases. The predominant fact in the instant case is that Harvest Power proposes to locate its facility on RCID property. When one facility locates on the property of another, the law presumes that both facilities operate under "common control" such that PSD requirements must be applied.

A question of common control is not resolved simply by looking at ownership or the ability of one facility to direct the management or policies of another. Harvest Power provided the Department with contractual agreements between itself and RCID that make clear that these are separate entities.[2] Common control for purposes of PSD preconstruction review also exists where one facility serves to support the activity of another. Both the existence and content of the PPA and WSA illustrate that the proposed Harvest Power facility will serve to support RCID activities.[3] Specifically, as indicated by Harvest Power, the intent of the project is to "fulfill[] the District's biosolids disposal and power generation needs."[4]

Notably, the efficacy of the proposed facility depends on Harvest Power's ability to sell power.[5] The PPA, however, allows RCID to restrict Harvest Power's ability to sell power. In particular, the PPA prohibits Harvest Power from selling power to other entities without RCID's consent, while capping the amount of power that RCID must purchase from Harvest Power.

The facility also serves to support RCID's waste disposal obligations. While the waste throughput of the proposed Harvest Power facility is uncertain,[6] the WSA requires Harvest Power to accept all organic waste delivered to it by RCID under penalty of default, and prohibits Harvest Power from transferring RCID's organic waste to another facility. In the event of a default, the WSA provides RCID with the right to purchase the Harvest Power facility at fair market value or require that Harvest Power completely remove the facility from RCID's property. The WSA provides additional, unilateral termination rights to RCID, such as the ability to terminate the WSA for default if Harvest Power comes into "public disrepute." The WSA also provides RCID with unilateral, liberal termination rights after five years for non-default.[7]

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[1] The Reedy Creek Improvement District (RCID) owns both an existing wastewater treatment plant and power plant with the same first two-digit SIC ("49" for electric, gas, and sanitary services) as the proposed Harvest Energy plant.

[2] Harvest Power provided the Department with confidential copies of an executed Power Purchase Agreement (PPA) and an executed Waste Supply Agreement (WSA) between itself and RCID.

[3] RCID functions to provide, among other things, utility service such as power and waste disposal to the owners of land within the District. See pages 2-3 of April 11, 2012 letter from Harvest Power's legal counsel to the Department (letter marked confidential).

[4] See page 6 of the April 11, 2012 letter.

[5] See page 3 of May 10, 2012 letter from Harvest Power's engineering consultant to the Department (letter marked confidential).

[6] Compare page 3 of the application report with page 2 of the April 11, 2012 letter and May 18, 2012 email from Harvest power's engineering consultant to the Department.

[7] See page 6 of the May 10, 2012 letter.

Considering all factors including those discussed above, the Department concludes that there is common control since the Harvest Power facility is a support facility for RCID. Therefore, the project is considered an expansion of the existing PSD major stationary source and is subject to PSD preconstruction review. Emissions increases from the project will be evaluated based on the PSD significant emission rates. Nevertheless, the Department intends to issue to Harvest Power Orlando, LLC a separate PSD air construction permit to build the proposed plant and, eventually, a separate Title V air permit to operate the plant.

3.3. PSD Applicability Analysis

The project will be located in Orange County, which is in an area that is currently in attainment with the AAQS or otherwise designated as unclassifiable. Table 2 summarizes the annual emissions from the project as defined in the application. The table compares these emissions to the PSD significant emission rates.

Table 2 - Annual Emission Summary and PSD Applicability

Pollutant	Engines	Bio-Scrubber	Flare	Project Potential Emissions (TPY) [1]	Significant Emissions Rate (TPY)	Subject to PSD?
CO	216.5	---	11.2	228	100	**Yes**
NO_X [2]	36.7	---	2.4	39	40	No [2]
$PM/PM_{10}/PM_{2.5}$	2.1	---	0.4	3	25/15/10	No
SO_2 [3]	8.94	---	29.6	39	40	No [3]
VOC	43.3	17.5	4.3	65	40	**Yes**
H_2S	0.1	0.7	0.3	1	10	No

Notes:

1. The potential emissions are based on the worst-case scenario operating the bio-scrubber and engines 8760 hours/year and along with 19% of the maximum annual designed biogas generation rate being combusted in the flare.
2. The applicant estimated potential annual NO_X emissions of 86.6 TPY from the engines based on an emission factor of 2.0 gram/brake horsepower-hour (g/bhp-hour), which is the applicable New Source Performance Standard in Subpart JJJJ of 40 CFR 60. However, the Department discussed with the applicant the vendor emissions data, which identifies an engine setup for low-energy fuels with a NOx emission factor as low as 0.5 g/bhp-hour. The draft permit includes a NOx cap for the project of 39 TPY.
3. The biogas is scrubbed to remove H_2S prior to combustion in the engines; however, the biogas is not scrubbed prior to combustion in the flare. Therefore, the draft permit includes an SO_2 cap for the project of 39 TPY. It is assumed that all sulfur in the biogas will be converted to SO_2 when combusted.

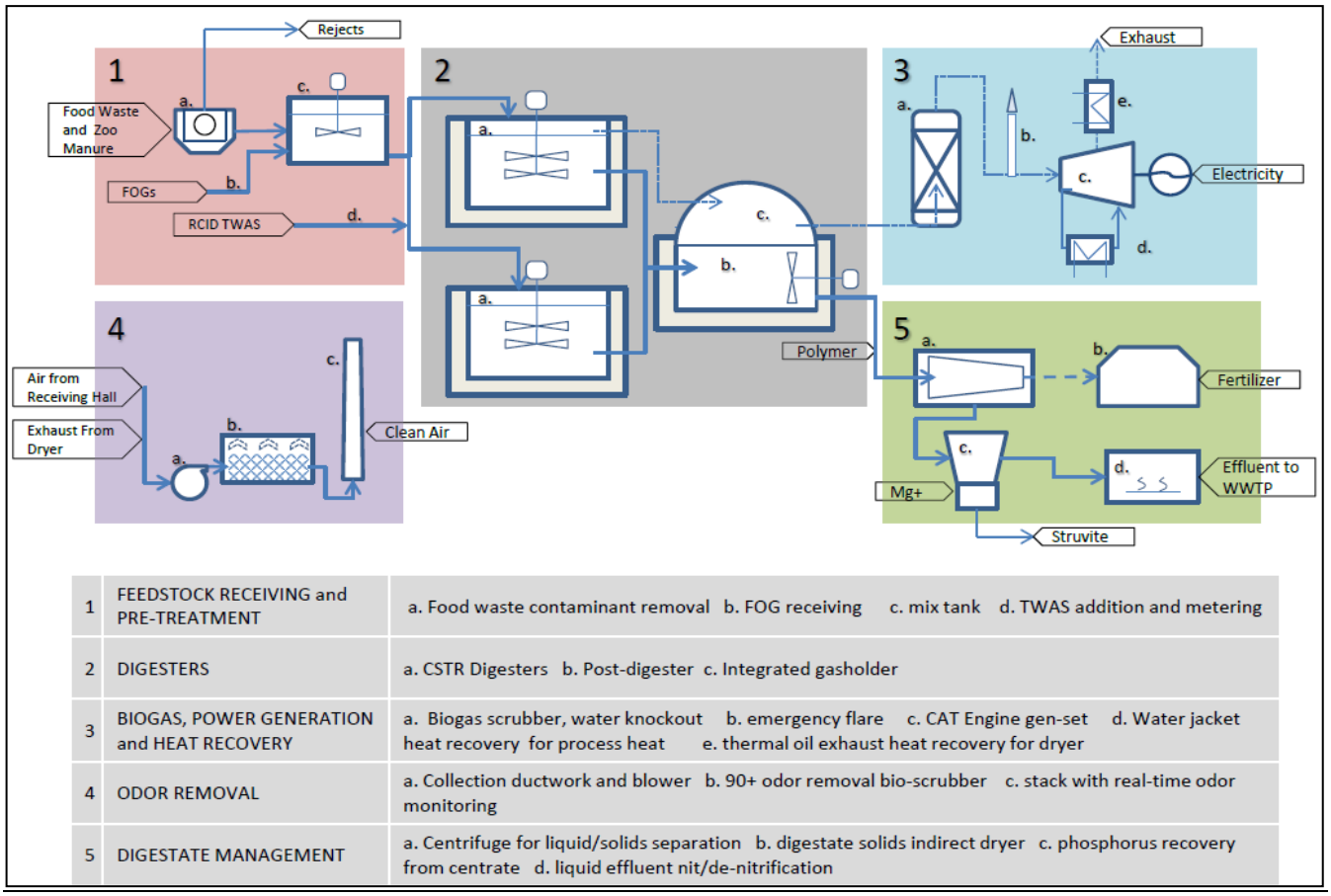
As shown in the above table, the project is subject to PSD preconstruction review for CO and VOC emissions in accordance with the provisions of Rule 62-212.400, F.A.C. Therefore, BACT determinations and air quality modeling analysis are required for CO and VOC emissions.

4. DEPARTMENT'S PROJECT REVIEW AND PSD ANALYSIS

Emission sources associated with this facility include two identical 1.6 MW Caterpillar Model G3520C reciprocating internal combustion engine/electrical generator sets (EU 001 and 002), an backup flare (EU 003) and a bio-scrubber (EU 004).

4.1. Process Description

The facility will consist of the following five main sections as shown in Figure 3 below.



1	FEEDSTOCK RECEIVING and PRE-TREATMENT	a. Food waste contaminant removal b. FOG receiving c. mix tank d. TWAS addition and metering
2	DIGESTERS	a. CSTR Digesters b. Post-digester c. Integrated gasholder
3	BIOGAS, POWER GENERATION and HEAT RECOVERY	a. Biogas scrubber, water knockout b. emergency flare c. CAT Engine gen-set d. Water jacket heat recovery for process heat e. thermal oil exhaust heat recovery for dryer
4	ODOR REMOVAL	a. Collection ductwork and blower b. 90+ odor removal bio-scrubber c. stack with real-time odor monitoring
5	DIGESTATE MANAGEMENT	a. Centrifuge for liquid/solids separation b. digestate solids indirect dryer c. phosphorus recovery from centrate d. liquid effluent nit/de-nitrification

Figure 3: Harvest Energy Garden – Orlando Process Flow Diagram

4.1.1. Feedstock Receiving and Pre-Treatment

Organic feedstock will be brought onsite and delivered into the receiving building where it will be fed into a separation device to remove the inorganic material prior to digestion. The feedstock will consist primarily of skimmings from a lift station, wastewater system grease traps (fat, oil, and grease - FOG) and brown grease, food waste, primate manure with bedding, thickened wastewater activated sludge (TWAS), other forms of biosolids from the Reedy Creek Development District and other industrial, commercial and institutional sources from other sources. The thickened wastewater activated sludge will be sent directly to the anaerobic digestion system. The inorganic material (plastic, metals, glass, etc.) will be collected and shipped offsite to a landfill. The organic material will be loaded into tanks and blended with the FOG (including brown grease) from a separate waste mixing tank.

4.1.2. Digesters

The anaerobic digestion process includes two continuously stirred tank reactor (CSTR) digesters. The waste will be transferred from the mixing tanks through a heat exchanger to elevate the processing temperature of the digester prior to pumping the material into the tank reactors. Once inside the digester tank, all the feedstock material and biological digester solids will be continuously mixed by a central, vertical agitator. The digester tanks will maximize organics destruction and biogas/methane generation while minimizing digestion volume and residual digestate production requiring dewatering and disposal. To promote biological growth, process water from the gravity belt filter system at the Reedy Creek wastewater treatment facility will be used in the digester to maintain an appropriate ammonia-nitrogen level. The digesters will breakdown the organics in the slurry to

methane (CH_4) and CO_2. As shown in Figure 4 below, the anaerobic digester allows the organic matter to decompose in a contained environment to create a biogas with a methane content of approximately 57%.

Organic Matter "Waste" → **Acid Forming Bacteria** → **Organic Acids (Acetic Acid) CH_3COOH** → **Methane Forming Bacteria**

$$\underset{57\%}{CH_4} + \underset{43\%}{CO_2} + \text{Heat} + \text{Water}$$

Figure 4: Anaerobic Decomposition Process

The digestate will leave the digester tanks by gravity and flow into the post digester with an integrated gasholder. The storage capacity of the post digester is approximately 4,200 cubic meters (m^3) of sludge and 4,000 m^3 of biogas. The post digester will be mixed by two low-speed lateral agitators with a motor outside the tank. The sludge will be monitored by measuring the hydraulic pressure at the bottom of the tank.

The gasholder system will be located on top of the post digester. The gas-holding capacity will be sized for a residence time of 2.25 hours on average or 4,000 m^3. A support structure will be installed to avoid contact with the liquid inside the tank. The system will be equipped with a combined hydraulic over/under pressure device and an alarm system that will sound prior to activation of the safety device.

4.1.3. Biogas, Power Generation and Heat Recovery (EU 001 and 002)

Biogas is referred to as gas produced by the biological breakdown of organic matter in the absence of oxygen (O_2). Organic matter comes from a once-living organism, which is capable of decaying, is a product of decay, or is composed of organic compounds. Organic compounds are composed of gaseous, liquid or solid chemical compounds whose molecules contain carbon.

Biogas is produced through the anaerobic decomposition (fermentation) of organic waste, such as manure, municipal solid waste, biodegradable waste, biodegradable feedstock or other similar materials. Biogas consists primarily of CH_4 (50% - 80%) and CO_2 (20% - 50%) with traces of hydrogen, CO, NO_X, oxygen (O_2) and H_2S. The applicant estimates the biogas will have a methane content of approximately 57%. The estimated biogas generation rate is 15.6 million cubic meters per year (m^3/yr), or the equivalent of 8.9 million m^3/yr of methane.

From the gasholder, the biogas will be directed to the biogas scrubber, which will reduce the H_2S concentration in the gas from approximately 3,000 parts per million (ppm) to less than 200 ppm (up to 98% removal). Particulate matter and some water vapor will also be removed as the gas passes through the condensate trap/gravel filter. Only the biogas that passes through the scrubber to remove H_2S and water will be delivered to the engines. Biogas that will not go through the scrubber will be routed to the backup flare.

The biogas will be combusted in two identical Caterpillar Model G3520C engine/generator sets for the production of electricity, all of which will be sold to the grid. Heat from the engine exhaust will be recovered and used to provide indirect heat for a dryer to further dry the final fertilizer product. The engine/generators will have the following specifications:

- Each engine is designed to fire at low-pressure and produce low emission levels from combustion. Each engine is equipped with an air-to-fuel ratio controller to monitor engine performance parameters and automatically adjust the air-to-fuel ratio and ignition timing to maintain efficient fuel combustion, which also minimizes air pollutant emissions.
- Each engine will be fired exclusively with biogas generated by Harvest Energy.
- Each engine will fire a maximum of approximately 525 scfm of biogas.
- Each engine will have power rating of 2,242 brake horsepower (bhp).
- Each engine will be connected to an electrical generator rated at 1.6 MW, nominal.

- Based on a biogas heating value of 581.4 British thermal units (Btu) per scf, the maximum heat input rating for each engine is 18.23 million Btu (MMBtu) per hour. The heat content is based on 1,020 Btu/scf for methane with a methane content of 57% in the biogas.

With both engines operating, the proposed biogas-to-energy project will have a total electrical generating capacity of 3.2 MW, nominal. Emissions produced by the combustion of biogas in each engine will be exhausted to ambient air through individual stacks connected to the engine exhaust manifolds. Each engine exhaust stack is 18.25 feet tall with a volumetric flow rate of 12,309 actual cubic feet per minute (acfm).

4.1.3.1. *NSPS Provisions for the Engines*

The biogas engines and generator sets are subject to applicable NSPS provisions in 40 CFR 60 for Subpart A (General Provisions) and Subpart JJJJ (Standards of Performance for Stationary Spark Ignition Internal Combustion Engines). These regulations establish operating limitations and emissions standards for CO, NO_X and VOC. Technical data sheets show that the engines will meet the emission limits established in NSPS Subpart JJJJ shown below in Table 3 for lean burn, spark-ignited engines firing biogas with a capacity of more than 500 hp. However, the vendor (Caterpillar) will not certify the Model G3520C engines when burning biogas as fuel and the engines must be tested to demonstrate compliance with these emissions standards.

Table 3 - Subpart JJJJJ and CAT G3520C Emission Standards and Proposed Emission Limits

Pollutant	Subpart JJJJ Standards	CAT G3520C Standard	Proposed Emission Limits
CO	5.0 g/bhp-hour	4.78 g/bhp-hour	5.0 g/bhp-hour
NO_X	2.0 g/bhp-hour	1.0 g/bhp-hour	2.0 g/bhp-hour
VOC	1.0 g/bhp-hour	0.54 g/bhp-hour	1.0 g/bhp-hour

4.1.3.2. *NESHAP Provisions for the Engines*

The biogas engines are subject to applicable NESHAP provisions in 40 CFR 63 for Subpart A (General Provisions) and Subpart ZZZZ (Reciprocating Internal Combustion Engines). Hazardous air pollutants as specified in Rule 62-210.200(155), F.A.C are produced during the combustion of biogas used as fuel by the internal combustion engines since:

- HAP compounds are present in the gas generated by Harvest Energy and the fuel combustion process is not 100% complete i.e., a small portion of the HAPs pass through the fuel combustion system; and
- When combusted, methane compounds present in biogas can form formaldehyde (CH_2O), which is a regulated HAP.

The engine technical data sheet provided by Caterpillar was used to estimate the total potential HAP content of the biogas to be used as fuel. Based on the maximum operating scenarios, the applicant estimated total annual HAP emissions (engines only) to be 19.05 tons/year, which is greater than 10 tons/year threshold to be considered a major source of HAP. However, per §63.6600(c) of NESHAP Subpart ZZZZ, any stationary reciprocating internal combustion engine that combusts landfill gas or digester gas equivalent to 10% or more of the gross heat input on an annual basis is exempt from any emission limits and operating limitations contained in the subpart. The other requirements of NESHAP Subpart ZZZZ are met by meeting the requirements of NSPS Subpart JJJJ.

4.1.4. Bio-Scrubber for Odor Removal (EU 003)

Air from the receiving building, as well as the digestate management area and dryer will be sent to a bio-scrubber in order to reduce the emission of any odor producing compounds. The bio-scrubber system will control the emission of VOC, HAP and other odor causing pollutants from the receiving building, three holding tanks, and the digestate handling and drying system.

The majority of the digestate from the anaerobic digester will be captured. A separation device will be used to

remove the liquid effluent for hydraulic control and recycle the active solids back to the digester for enhanced biodegradation of the feed stocks. A centrifuge will be used to separate and capture approximately 95% of the solids with no polymer. The recycling of the digestate will increase the sludge age within the digester, which will result in better treatment performance and more biogas generation.

The dewatered solids will be fed to an indirect-heated dryer that produce 90% or more dry Class A/AA fertilizer material that will in turn be sold. The dryer will receive heat through the thermal oil heating system. The oil will be heated by the exhaust gases from the engine/generator sets. The oil will then be piped to the dryer to heat the air entering the dryer.

The effluent from the centrifuge will be directed to a nutrient recovery system designed to remove soluble phosphorus and nitrogen before sending the final effluent back to Reedy Creek wastewater treatment facility. Magnesium ammonium phosphate (struvite) is another byproduct that can be produced and sold as a nutrient fertilizer.

4.1.4.1. *NSPS Provisions for the Dryer*

NSPS Subpart LLLL of 40 CFR 60 applies to sewage sludge incineration units.

> *Sewage sludge incineration unit is defined as incineration unit combusting sewage sludge for the purpose of reducing the volume of the sewage sludge by removing combustible matter. Sewage sludge incineration unit designs* ***include fluidized bed and multiple hearth*** *…*

The dryer is indirectly heated by a thermal oil heating system, which does not meet the definitions of sewage sludge incinerator or sludge dryer as defined in NSPS Subpart LLLL of 40 CFR 60, therefore this system is not subject to the regulations established in NSPS Subpart LLLL.

4.1.4.2. *NESHAP Provisions for the Dryer*

NESHAP Subpart E of 40 CFR 61 applies to those stationary sources which … incinerate or dry wastewater treatment plant sludge.

> *Sludge dryer is defined as "a device used to reduce the moisture content of sludge by heating to temperatures above 65 °C (150 °F)* ***directly*** *with combustion gases.*

The dryer is indirectly heated by a thermal oil heating system, which does not meet the definitions of sewage sludge incinerator or sludge dryer as defined in NESHAP Subpart E of 40 CFR 61; therefore the indirectly heated dryer is not subject to the regulations established in NESHAP Subpart E.

4.1.5. <u>Backup Flare (EU 004)</u>

The applicant proposes to install and operate a "candlestick-type" flare with the following specifications:

- Maximum design flow rate of 1,200 scfm candle type open flare.
- Based on a heating value of 1,020 Btu/scf for methane and a methane content of 57% in the biogas, the maximum heat input rate is 41.9 MMBtu/hour.
- The open flare stack is 8 inches in diameter and 24 feet in height with a volumetric flow rate of 3,454 acfm.
- The flare is designed for an overall 98% destruction efficiency of total hydrocarbons for biogas with a methane content between 40% and 60%.
- Type "K" flame monitoring thermocouple assembly.
- Maximum estimated annual rate was based on 10% of the biogas production rate, which is equivalent to 1.56 million m^3/year (31,936 MMBtu/year) of biogas burned in the flare.

4.1.5.1. *NSPS Provisions for the Flare*

The flare is subject to applicable NSPS provisions in 40 CFR 60 for Subpart A (General Provisions). These

regulations establish design specifications, operating limitations, and emissions standards for visible emissions. The vendor, Perennial Energy, Inc., provided technical data sheets for Model No FLR-301 (or equivalent) flare showing that the flare is designed to meet criteria established in NSPS Subpart A in 40 CFR 60.18.

4.2. Pollutant Emissions From Project

4.2.1. CAT G3520C Engines/Generators (EU 001 and 002)

4.2.1.1. *Overview of CO, VOC and NO_X Emissions*

The applicant proposed the following maximum emission rates for the CAT G3520C engines:

- NO_X: 2.0 g/bhp-hour
  9.87 lb/hour and 43.3 tons/year per engine and 86.6 tons/year for both engines
- CO: 5.0 g/bhp-hour
  24.72 lb/hour and 108.25 tons/year per engine and 216.49 tons/year for both engines
- VOC: 1.0 g/bhp-hour
  5.0 lb/hour and 21.66 tons/year per engine and 43.3 tons/year for both engines
- $PM/PM_{10}/PM_{2.5}$: 0.0131 lb/MMBtu
  0.24 lb/hour and 1.05 tons/year per engine and 2.09 tons/year for both engines
- SO_2: 200 ppmvd of H_2S and 522.5 scfm
  1.02 lb/hour and 4.47 tons/year per engine and 8.94 tons/year for both engines

Potential NO_X, CO and VOC emissions were based on the emission standards specified in NSPS Subpart JJJJ of 40 CFR 60. Sulfur dioxide emissions can be produced during the combustion of biogas since it contains sulfur-bearing compounds (such as H_2S) that are oxidized at normal engine operating temperatures. Site-specific sulfur content analyses have not been performed on the biogas generated by the organic solid waste. Potential SO_2 emissions were estimated based on a maximum design H_2S content of the biogas of 200 ppmvd (98% removal). It is assumed that all the H_2S is converted to SO_2 during combustion of the biogas. Particulate matter emissions were based on engine vendor data.

Emissions data from Caterpillar indicates a not to exceed (NTE) CO emission level of 4.78 g/bhp-hour. Site-specific emissions testing in Florida for these engines firing biogas have not been done. However, several previous projects using the CAT G3520C engines firing landfill gas (LFG) have been installed and are in operation. Annual compliance tests conducted at these facilities are shown in Table 4.

Table 4 - CO, NO_X and VOC for Landfill Gas Fired in Internal Combustion Engines

Facility	Actual Output (kW)	NO_X (g/bhp-hr)	CO (g/bhp-hr)	VOC (g/bhp-hr)
Brevard Energy – No. #3	1,600	0.45	2.4	-
Brevard Energy - No. #4	1,609	0.35	2.61	-
Brevard Energy - No. #5	1,602	0.43	2.39	0.186
Brevard Energy - No. #6	1,582	0.37	2.23	-
Seminole Energy - No. #1	1,586	0.4	2.66	-
Seminole Energy - No. #2	1,550	0.39	2.61	-
Seminole Energy - No. #3	1,614	0.37	2.52	-
Seminole Energy - No. #4	1,589	0.28	2.61	0.23
Trail Ridge Energy - No. #4	1,577	0.43	2.4	-
Trail Ridge Energy - No. #9	1,581	0.46	2.56	-

As shown in the Table 4, actual tested emissions of NO_X, CO and VOC from these engines are well below the proposed emissions limits established in NSPS Subpart JJJJ of 40 CFR 60 and requested by the applicant. While

these CO compliance test results are significantly less than the manufacturers NTE limit, variability in the LFG/biogas fuel methane content and engine maintenance cycles will have a significant impact on projected CO emissions in the future.

In 2004, the Los Angeles County Sanitation Districts and SCS Energy issued a paper "Siloxanes in Landfill and Digester Gas Update[8]." The paper discusses the difficulties and obstacles in understanding siloxanes and how digester and LFG are widely used as fuel to produce electricity, drive pumps and fire boilers. Siloxanes are found in wastewater and in solid waste deposited in landfills. These gases are normally saturated with moisture and carry varying quantities of compounds that contain sulfur, chlorine and silicon. When this gas is combusted to generate power, such as in internal combustion engines, siloxanes are converted to silicon in the exhaust stages of the equipment. Evidence of siloxanes in biogas is found in the form of a white powder on combustion surfaces in reciprocating engines (turbines, heat exchangers, etc.) and as a light coating on post-combustion catalysts. The white powder is primarily silicon dioxide, a product of siloxanes combustion. Individual siloxanes compounds are commonly near or below their limits of detection in raw biogas samples. However, manufacturers of this equipment (reciprocating engines and combustion turbines, etc.) now feel obligated to impose siloxanes standards where they have not been imposed before.

The Bay Area Air Quality Management District issued a white paper[9] discussing this very issue. Based on test data (62 individual tests) for firing landfill gas in three types of spark-ignited reciprocating internal combustion engines (15 total engines), the report indicates the following:

- The engines were annually demonstrating compliance with the CO and NO_X standards; however, this appeared to be more of a function of careful preparation of the engine for the annual test rather than the design of the engine.
- The same engine type could be "biased for low NO_X emissions" (0.5 g NO_X/bhp-hour or less with greater than 2.1 g CO/bhp-hour) or "biased for low CO emissions" (2.1 g CO/bhp-hour or less with greater than 0.5 g NO_X/bhp-hour) depending on the air-fuel controller.
- The exhaust from some of the tested engines was periodically monitored throughout the year by hand-held portable probes. This data showed degradation with regard to CO emissions such that many engines were frequently in excess of the low CO BACT standard. The report indicates a gradual CO increase of up to 1.5 g/bhp-hour over a year of operation.

The conclusion of the report is that CO and NO_X emissions standards should be paired when relying on combustion design and control. As shown below, the Bay Area Air Quality Management District chose to establish standards based on a low NO_X bias or a low CO bias and then allow the CO standard to increase approximately 1.5 g/bhp-hour over a year of operation calling the upper CO standard a "not to exceed" limit:

Low NO_X Bias:	NO_X:	0.5 g/bhp-hour
	CO:	2.5 g/bhp-hour (and NTE 3.9 g/bhp-hour)
Low CO Bias:	NO_X:	0.6 g/bhp-hour
	CO:	2.1 g/bhp-hour (and NTE 3.6 g/bhp-hour)

The emission controls were based on the engine design and good combustion practices (including maintenance). The Department is unaware of any new control equipment that would be cost effective. Siloxane deposits degrade the performance of the engine and extensive maintenance is required to restore the combustion equipment to proper operation. As the engine performance degrades, it is difficult to maintain the engine tuned for low CO and NO_X emissions.

[8] "Siloxanes in Landfill and Digester Gas Update"; Los Angeles County Sanitation Districts and SCS Energy; 2004.

[9] "Revisiting BACT for Lean Burn Landfill Gas Fired Internal Combustion Engines"; Toxics Section, Engineering Division, Bay Area Air Quality Management District; February 26, 2009.

Therefore, the landfill gas facilities in Florida have requested permits to increase the CO BACT emissions standard stating that the gradual degradation of the engines will cause higher CO emissions. The Department reconsidered these previous determinations because of the inverse relationship between CO and NO_X emissions. In other words, an engine set can be tuned to achieve low NO_X emissions at the price of higher CO emissions or vice versa. Therefore, the Department approved higher CO emission limits of 3.5 g/bhp-hour paired with a NOx standard of 0.6 g/bhp-hour for Brevard Energy, Seminole Energy, and Trail Ridge Energy.

For this project, the Department notes that specifying a NOx standard of 0.6 g/bhp-hour paired with a CO BACT determination of 3.5 g/bhp-hour would make the project minor with respect to NOx emissions.

4.2.1.2. *Avoidance of PSD for NO_X Emissions*

Based on the above discussion and the vendor specifications for low energy fuels (e.g., landfill gas and biogas), the Department will allow an engine setup for a "low NOx bias" to avoid triggering PSD review for NO_X emissions. The draft permit will specify a NO_X emissions cap of 39 TPY for the project. Although the NO_X emissions limit for each engine will be specified as the NSPS Subpart JJJJ limit of 2.0 g/bhp-hour, actual tested NOx emissions are expected to be less than 0.6 g/bhp-hour based on the low-NOx bias setup. To comply with the NOx emissions cap, the actual tested NOx emissions will be used in conjunction with the engine hours to determine actual annual emissions. The CO BACT limit along with the NOx emission cap is discussed further in **subsection 5.1.2.4**.

4.2.2. Bio-Scrubber System (EU 003)

The applicant proposes to control the emissions of VOC, HAP, H_2S, and other odor causing pollutants by venting air from the receiving building, the three holding tanks, and the digestate handling/drying system to a bio-scrubber. The maximum throughput rate of the bio-scrubber is 20 million gallons/day. The bio-scrubber is expected to reduce HAP and VOC emissions by approximately 99%; however, the applicant used a conservative estimate of 90% reduction in the application. Emissions produced by the bio-scrubber will be exhausted to ambient air through an exhaust stack that is 60-feet tall and has a volumetric flow rate of 40,590 acfm. Table 5 summarizes applicant estimates of the bio-scrubber's potential emissions.

Table 5 - Bio-Scrubber Potential Emissions

Pollutant	Tons/Year
VOC	17.46
HAP	1.17
TRS, including H_2S	0.70
Ammonia	0.94

4.2.3. Backup Flare (EU 004)

The flare will operate under the following scenarios: when the engines are not available because of downtime or maintenance; or when biogas is generated in excess of the design fuel requirements of the engines. The biogas will not be treated when combusted in the flare.

Proposed flare emissions are summarized in Table 6. These emissions are based on the assumption that 10% of the maximum annual biogas generation will be combusted in the flare. Table 6 also provides emission estimates assuming that 19% of the biogas is combusted in the flare.

Table 6 - Flare Potential Emissions [1, 2]

Pollutant	Hourly Emissions, lb/hour	Annual Emissions, Tons/Year	
	Potential Flare Emissions	Potential Flare Emissions (10% of max. bio-gas)	Potential Flare Emissions (19% of max. bio-gas)
NO_X	2.88	1.28	2.4
CO	13.32	5.91	11.2
SO_2	35.14	15.59	29.6
VOC	5.04	2.24	4.3
$PM/PM_{10}/PM_{2.5}$	0.47	0.21	0.4

Pollutant	Hourly Emissions, lb/hour	Annual Emissions, Tons/Year	
	Potential Flare Emissions	Potential Flare Emissions (10% of max. bio-gas)	Potential Flare Emissions (19% of max. bio-gas)
H_2S	0.38	0.17	0.3

Notes:

1. Maximum estimated H_2S emissions from digesters and 100% conversion to SO_2.
2. SO_2 emission based on complete destruction of H_2S in flare. Combined SO_2 emissions from flare and engines will be less than the PSD significant emission rate of 39 TPY.

As shown in Table 6, the potential emissions produced from the flare are less or equal to the emissions produced by the engines except for PM and SO_2, with SO_2 governing with respect to PSD applicability. To increase the operational flexibility of the facility, especially during commissioning, the Department will allow up to 19% of the maximum annual generating rate of biogas (15.6 MMm^3/year) to be combusted in the backup flare. The draft permit will specify an annual limit of 2.96 MMm^3 of biogas fired in the flare to provide reasonable assurance that the project will not exceed the significant emission rate of SO_2 of 40 TPY.

4.2.4. GHG Emissions

On May 13, 2010, EPA established the tailoring rule establishing major source thresholds for greenhouse gases (GHG) of 100,000 tons/year (in terms of CO_{2e}) for greenfield projects not already subject to PSD and 75,000 TPY for greenfield projects already subject to PSD for another regulated pollutant. The applicant estimates GHG emissions from the project to be 46,098 tons/year, which is approximately 61% of the 75, 000 TPY CO_{2e} threshold.

5. BACT DETERMINATION

The project is subject to PSD preconstruction review for CO and VOC emissions. As previously described, the Department will impose a NOx emissions cap of 39 TPY for the project to avoid triggering PSD review for this pollutant.

5.1.1. General Discussion of CO and VOC Emissions

The biogas engines are the primary source of CO and VOC emissions from this project. Table 7 summarizes the potential annual emissions produced from the engines, bio-scrubber and backup flare. As seen the primary source of emissions are the biogas engines. Consequently, the Department accepts the control technologies proposed by the applicant to control VOC and CO emission from the bio-scrubber (scrubbing) and flare (good combustion practices) as BACT. The rest of this discussion will pertain to the biogas engines (EU 001 and 002)

Table 7 - Potential Annual Emissions

Pollutant	TPY		
	Biogas Engines (EU 001 and 002)	Bio-Scrubber (EU 003)	Backup Flare (EU 004)
CO	216.49	---	11.22
VOC	43.3	17.45	4.26

The Department reviewed data in EPA's RACT/BACT/LAER Clearinghouse (RBLC) to identify control technology determinations for the operation of reciprocating internal combustion engines firing low energy gaseous fuels, primarily landfill gas. Table 8 summarizes the emissions information.

Table 8 - CO and VOC BACT Determination for Landfill Gas Fired Internal Combustion Engines [1].

Facility	Engine Type and Size	Date	Control Method CO/NO_X	Type	g/bhp-hour		
					CO	NO_X	VOC
Waste Management, Inc. Medley Landfill (FL)	CAT 3520 2233 HP	5/3/2011	Oxidation Catalyst	BACT/CBC	3.5	9.9	0.163
Sampson County Disposal, LLC (NC)	CAT 3520 2233 HP	09/09/2009	GCP	BACT	2.75	0.5	---
Renewable Energy, LLC Moretown Facility(VT)	CAT 3520 1600 kW	9/15/2008	---	CBC	2.75	---	---
Pine Tree Landfill (ME)	LFG-ICE 1359 HP	10/15/2007	---	BACT	2.75	0.6 [2]	---
University of New Hampshire (NH)	LFG-ICE 2233 HP	07/25/2007	Combustion Controls	BACT/LAER	2.75	0.5	---
Waste Management Midpenn (VA)	CAT 3516 1148 HP	05/29/2007	GCP	BACT	2.7 [3]	1.45 [4]	---
Brevard Energy, LLC (FL)	CAT 3520 2233 HP	03/06/2007	GCP	BACT/CBC	3.5	0.6	0.28
Seminole Energy, LLC (FL)	CAT 3520 2146 HP	01/17/2007	GC	BACT/CBC	3.5	0.6	0.24
Monmouth County Reclamation Center (NJ)	LFG-ICE 1468 HP	12/12/2006	---	CBC/LAER	2.53	0.53	0.33
Manchester Renewable Power Corp. (NJ)	CAT 2233 HP	10/06/2006	A/F Controller	BACT/LAER	2.75	0.5	0.16
Burlington County Resource Recovery (NJ)	Jenbacher 2012 HP	08/03/2006	GCP	CBC/LAER	2.5	0.6	0.4[c]
Trail Ridge Energy, LLC (FL)	CAT 3520 2233 HP	02/24/2006	GC	BACT	3.5	0.6	0.28
Ridgewood Rhode Island Generation (RI)	CAT 3520 2229 HP	01/05/2005	A/F Controller	BACT/LAER	2.75	0.5	0.15 [5]
New England Waste Services (VT)	CAT 3520 2221 HP	12/16/2004	---	CBC	2.75	0.5	---
Bio Energy Texas, LLC (TX)	CAT 3520 2172 HP	07/23/2004	Lean Burn Design	BACT	2.8	0.6	0.16
Northwest Regional Landfill (AZ)	LFG-ICE 1410 HP	10/27/2003	Proper Operation & Maintenance	BACT	2.5	0.6	---
Carbon Limestone LFG (OH)	LFG-ICE 1877 HP	04/10/2003	Lean Burn Design	BACT	2.0	0.6	0.17 [6]
Chino Basin Desalter Authority (CA)	LFG/DG-ICE 1408 HP	06/18/2002	A/F Controller	BACT	2.5	0.6	0.8
MM San Bernardino Energy (CA)	LFG-ICE 1850 HP	05/16/2002	A/F Controller	BACT	2.5	0.6	0.8
Reliant Security LFGTE (TX)	Jenbacher 2231 HP	01/31/2002	GCP	BACT	3.0	0.6	0.28
Reliant Energy Galveston Plant (TX)	Jenbacher 2343 HP	01/24/2002	---	CBC	3.0	0.6	0.16 [7]

Notes:

1. Abbreviations: horsepower (HP); landfill gas (LFG); internal combustion engines (ICE); case-by-case (CBC); good combustion practices (GCP); good combustion (GC); and air/fuel controller (A/F controller)

2. Project shows BACT limit for NO_X as 1.79 lb/hour per engine, conversion to g/bhp-hour.
3. Project shows BACT limit for CO as 239 tons/year and NO_X as 128.30 tons/year, conversion to g/bhp-hour.
4. Project shows BACT limit for NO_X as 1.77 lb/hour and 20 ppmvd per engine, conversion to g/bhp-hour.
5. Project shows BACT limit for VOC as 0.76 lb/hour and 20 ppmvd, conversion to g/bhp-hour.
6. Project shows BACT limit for VOC as 0.7 lb/hour and 3 tons/year per engine, conversion to g/bhp-hour.
7. Project shows BACT limit for VOC as 0.83 lb/hour and 24.72 tons/year, conversion to g/bhp-hour.

The specified BACT/LAER determinations for CO and NO_X are applicable to the operation of lean-burn engines with air-to-fuel ratio control. The proposed Caterpillar Model G3520C engines have a power rating of 2,242 bhp. As shown in the table, for landfill gas engines rated greater than 1,100 bhp and less than 2,343 bhp, the CO BACT ranges from 2.27 to 3.5 g/bhp-hour, with a corresponding NO_X BACT/LAER range from approximately 0.5 to 0.6 g/bhp-hour. The VOC BACT ranges from 0.15 to 0.28 g/bhp-hour. It is important to note that the low CO BACT determination of 2.7 g/bhp-hour corresponds to a NO_X BACT standard of 1.45 g/bhp-hour.

5.1.2. BACT Determinations for CO and VOC from Engines

Combustion byproducts are generally controlled by an efficient combustion design, but catalytic technologies are available for reducing these emissions. Since CO and VOC emissions are related combustion byproducts, these pollutants will be grouped together for convenience of review.

5.1.2.1. Identification of Control Technologies

The following control technologies are provided:

- *Combustion Design and Air-Fuel Controllers:* The design and operation of the combustion chamber is the primary mechanism in controlling CO emissions. The proposed Model G3520C engines are designed for high-combustion efficiency to extract the most useful energy from the landfill gas, digester gas and biogas as possible, which will minimize CO emissions. Combustion controls include technologies designed to limit the formation of CO by controlling the combustion temperature and the mixing of air and fuel in the combustion zone. The proposed engines are lean-burn engines equipped with an electronic air-fuel ratio controller that will minimize incomplete combustion and maintain a proper balance of CO.
- *Oxidation Catalyst:* In the presence of an oxidation catalyst at a given temperature, excess oxygen in the exhaust reacts with CO to form CO_2. This option includes non-selective catalytic reduction (NSCR). The primary design is a flow through exhaust device that contains a honeycomb structure covered with a layer of chemical catalyst that operates at high temperatures. This layer contains small amounts of precious metal that promote the complete oxidation of pollutants in the exhaust stream. This control device will reduce CO emissions as well as VOC emissions, depending on the type and concentration. Destruction efficiencies for CO and VOC emissions can be greater than 90%.
- *Regenerative Selective Catalytic Reduction (RSCR):* Regenerative selective catalytic reduction is a new technology targeted for tail-end applications that may also include an oxidation catalyst for CO reduction. RSCR utilizes beds of ceramic media to retain the temperature of the flue gas in the optimum range for the catalytic reaction (approximately 300º F to 400º F). Such systems are capable of 95% heat recovery, which minimizes operating costs while reducing CO emissions by 50% to 75%.

5.1.2.2. Discussion of Technically Infeasible Control Options and Ranking of Remaining Options

Biogas contains small amounts of siloxanes, which are a class of compounds that exist in the form of R_2SiO, where R is a hydrogen atom or a hydrocarbon and Si is silicon. When combusted, such compounds produce silica (SiO_2), which can quickly poison a catalyst rendering it ineffective. A separate treatment system to remove SiO_2 would be necessary to avoid the adverse effects of deposits and the rapid decrease in reactivity of the catalyst.

The California Air Resource Board (CARB) has developed and published *Guidance for the Permitting of Electrical Generation Technologies* in July 2002, to assist companies and organizations in the permitting of

electrical generating equipment. In this guidance document, CARB:

- Recognizes the benefits of generating electricity from waste gases (landfill, digester gas, and biogas) and the recovery of useful energy.
- Indicates that waste gases "… contain impurities that, if combusted will likely poison catalyst-based, post-combustion control systems."
- Determines that additional fuel treatment and post combustion controls have limited success and/or have not been proven to be cost effective in reducing air pollutant emissions from waste combustion applications.

Other state regulatory agencies (e.g., Texas, Rhode Island and New Jersey) have made similar determinations and issued permits that specify BACT for landfill gas-fueled engines that do not include the use of add-on emission controls because of catalyst poisoning by siloxanes. Such poisoning leads to poor reduction efficiencies and eventually destruction and early replacement of the catalyst. In the preamble to the NSPS for Stationary Spark Ignition Internal Combustion engines and the NESHAP for Reciprocating Internal Combustion Engines, EPA agrees siloxanes will poison the catalyst in add-on control technologies such as SCR, NSCR and oxidation catalysts, which makes the equipment ineffective in a very short period of time.

To employ a catalytic technology would require a siloxane removal system. For a previous project the Department contacted Applied Filter Technology (AFT), which has been active in the biogas-to-energy business since 1996 and has 167 biogas-to-energy systems in operation around the world. For ten years, the AFT siloxane removal systems have primarily been used in conjunction with combustion turbines to achieve guaranteed landfill gas specifications that are intended to protect the combustion turbines, which operate within close mechanical tolerances. The percentage of siloxane removal required for protecting a combustion turbine is much less than the siloxane removal efficiency required for protecting a catalyst. In addition, AFT does not have any experience in using the siloxane removal system for engines and the protection of the catalyst used in add-on control. It appears that a siloxane removal system that can protect the landfill gas, digester gas and biogas engines as well as the control catalyst is still in development.

In 2010, landfills permitted in the state of Florida to operate the Caterpillar Model G3520C reported siloxane levels of approximately 21 ppm (1.6 micrograms/Btu (µg/Btu)), which is higher than the level recommended by the engine manufacturer, Caterpillar (0.60 µg/Btu). This will mean more frequent preventative maintenance as well as major maintenance overhauls. Siloxane is also present in biogas and therefore, add-on control technologies using a catalyst are considered technically infeasible for this project due to premature deactivation by siloxanes. The remaining control option is combustion design and controls. As previously shown by the applicant, data in the RBLC database (2002 – 2011) supports the air-fuel controller and good combustion practices as BACT for engines firing low-energy gaseous fuels.

5.1.2.3. Selection of BACT and Rationale

As shown in Table 8, previous CO and VOC BACT determinations for low-energy gaseous fuels range from 2.0 to 3.5 g/bhp-hour and 0.15 to 0.8 g/bhp-hour, respectively. The applicant's proposed limits are based on the NSPS Subpart JJJJ emissions standards of 5.0 g CO/bhp-hour and 1.0 g VOC/bhp-hour, which is considered the floor for BACT. Caterpillar LLC specifies a "not to exceed" limit of 4.78 g CO/bhp-hour and 0.54 g VOC/bhp-hour at 100% load.

As previously discussed, the Department recently revised BACT determinations for several projects using the Caterpillar Model G3520C engines firing landfill gas to accommodate a low-NOx bias engine setup: 2.75 g CO/bhp-hour paired with 0.6 g NOx/bhp-hour. Stack testing has shown compliance with the standards, which are based on the applicants' proposals as well as the efficient combustion design and air-fuel controllers.

Considering all available information, the Department establishes the following BACT standards for each proposed engine:

CO: 5.0 g/bhp-hour (initial and annual EPA Method 10 stack test)
VOC: 1.0 g/bhp-hour (initial and annual EPA Method 18 stack test)

Because of uncertainties associated with biogas and considering the vendor's "not to exceed" limits for these pollutants, BACT for CO and VOC emissions are set at the recent NSPS Subpart JJJJ emissions standards for lean burn, spark-ignited reciprocating internal combustion engines firing digester gas with a capacity of more than 500 hp and manufactured after July 1, 2010. This provides maximum flexibility to tune the engines for low-NOx emissions and accommodate gradual equipment degradation from firing this low-energy fuel. The CO and VOC emissions will be controlled by the efficient combustion design, an air-to-fuel controller system, and good combustion and maintenance practices.

5.1.3. BACT Determination VOC from Bio-Scrubber

Without any control, emissions from the reception area, tanks and dryer are conservatively estimated to be: 39.8 lb/hour and 174.32 tons/year of VOC; 2.7 lb/hour and 11.7 tons/year of total HAPS; 1.6 lb/hour and 7.0 tons/year of TRS emissions; and 2.1 lb/hour and 9.4 tons/year of ammonia. The bio-scrubber will reduce/eliminate odors and VOC emissions in the air by controlling ventilation air from the receiving building, the three holding tanks and the digestate handling and drying system. The Department also notes the following information from a publication that has been approved as an EPA document on "Bio-filter for Removing Hazardous Organic Emissions from Soil, Water and Air Decontamination Processes."

> *"Bio-filtration is now a well-established air pollution control technology in several European countries … Control efficiencies of >90% have been achieved from many common air pollutants. Due to lower operating costs, bio-filtration if applied to appropriate systems can provide significant economic advantages over other air pollution control technologies. It is suitable for off-gases containing readily biodegradable pollutants in low concentrations, typically less than several thousand ppm as methane. Environmental benefits include low energy requirements for operation and a complete degradation of the pollutants ... Bio-filtration is a technology utilizing a fixed-biological film supported on the solid phase to remove air contaminants from off-gas streams through aerobic degradation … In summary, the use of bio-filtrations has demonstrated a viable and economical way to remove trace contaminants from air."*

The Department recognizes that the primary control for the reception building, tanks and dryer is a secured enclosure. The applicant provided vendor data, which identifies the following bio-scrubber system performance standards when loaded under average and peak conditions:

- Will achieve at least 90% removal of VOC emissions.
- Will provide at least 90% odor removal for inlet concentration levels between 5,000 and 15,000 Odorous Unit (OU). For inlet concentration levels less than 5,000 OU, the outlet concentration levels will be less than 500 OU.
- Will achieve at least 99% removal of H_2S or <0.1 ppm at the system discharge.

The Department determines that the bio-scrubber with a control efficiency of at least 90% represents BACT for VOC emissions. The draft permit requires the submittal of final design specifications to show compliance with this requirement.

5.1.4. BACT Determinations for CO and VOC from Flare

The flare is a backup device and operation is limited by permit to no more than 19% of the maximum annual design biogas generation rate. The Department determines that BACT for CO and VOC emissions from the flare is the inherent combustion design specified in accordance with NSPS Subpart A in 40 CFR 60.18.

5.2 NOx Emission Cap

As described in **subsection 4.2.1.2**, the NSPS Subpart JJJJ NO_X emission standard is 2.0 g/bhp-hour (9.9 lb/hr). However, tuning the Caterpillar Model G3520C engines for a low-NOx bias will result in actual NOx emissions of 0.6 g/bhp-hour or less based on vendor and stack test data for other low-energy gaseous fuels. Operation at

these levels will ensure that project emissions will be much less than the corresponding significant emission rate of 40 TPY for NO_X. Therefore, the Department establishes the following emissions cap for this project:

> Total NOx emissions from the combustion sources in this project (EU-001, EU-002, and EU-004) shall not exceed 39.0 tons during any consecutive 12 months.

Compliance with the NO_X emissions cap will be shown on a 12-month rolling basis by utilizing the following equation.

$$[(0.8 \text{ tons NOx/MMm}^3)(\text{Flare}_{\text{Biogas}})] + [(\text{EF}_{\text{engine}})(\text{lb/454})(\text{ton/2000 lb})(\text{Engine1}_{\text{bhp-hours}} + \text{Engine2}_{\text{bhp-hours}})] \leq 39.0 \text{ TPY, NOx}$$

Where:

$\text{Flare}_{\text{Biogas}}$	=	Rolling 12-month total of Biogas burned in flare (EU-004), million m^3 (MMm^3)
$\text{EF}_{\text{engine}}$	=	NOx emission rate from most recent annual stack test, g/bhp-hour
$\text{Engine}_{\text{bhp-hours}}$	=	Rolling 12-month total of operating bhp-hours for each engine (EU-001 and EU-002)

Example:

Assume the flare is operated at 50% of the maximum rate of biogas allowed by permit.

$$\text{NOx (Flare)} = (0.8 \text{ tons NOx/MMm}^3)\ (2.96 \text{ MMm}^3\text{/year})\ (0.5) = 1.2 \text{ TPY}$$

Also assume for engines: tested actual NOx emissions at 0.9 g/bhp-hour; total engine hours 15,856 hours/year (~90% of the time); and an average operating rate of 2,130 bhp (95% of capacity).

$$\text{NOx (Engines)} = (0.90 \text{ g/bhp-hour})(\text{lb/454 g})(\text{ton/2,000 lb})\ (15{,}856 \text{ engine hours/year})\ (2130 \text{ bhp}) = 33.5 \text{ TPY}$$

$$\text{Total NOx} = (1.2 + 33.5) = 34.7 \text{ TPY}$$

5.3 SO_2 Emission Cap

The biogas scrubber will remove more than 98% of the H_2S from the biogas before being fired in the engine/generators sets; however, biogas will not be scrubbed when it is necessary to use the flare. Although the applicant requested operation of the flare at 10% of the maximum designed biogas generation rate, the Department's experience indicates that the flare can be used much more than this during shakedown and the initial years of operation. The draft permit establishes a limit of combusting no more than 2.96 MM^3 of biogas in the flare, which is approximately 19% of the maximum designed biogas generation rate (15.6 MM^3 of biogas). To ensure that SO_2 emissions will not exceed the PSD significant emission rate of 40 TPY, the draft permit includes the following SO_2 emission cap.

> The emissions of SO_2 from the combustion sources in this project (EU-001, 002, and 004, combined) shall not exceed 39 tons per consecutive 12 months. Compliance with this SO_2 emissions cap shall be demonstrated on a 12-month rolling basis using the following information: the H_2S level in the biogas fired (scrubbed and unscrubbed), the amount of biogas fired in each combustion source, and the assumption that all sulfur is converted to SO_2.

The permit requires at least semiannual sampling and analysis of the H_2S content for the scrubbed and unscrubbed biogas and monitoring of the biogas flow rates to the engine/generator sets and flare.

6. AIR QUALITY IMPACT ANALYSIS

This section provides a general overview of the modeling analyses conducted for PSD preconstruction review followed by the specific analyses required for this project.

6.1. Overview of the Required Modeling Analyses

Pursuant to Rule 62-212.400, F.A.C., the applicant is required to conduct the following analyses for each PSD significant pollutant:

- A preconstruction ambient air quality analysis,
- A source impact analysis based on EPA-approved models, and
- An additional impact analyses.

6.1.1. Preconstruction Ambient Monitoring Analysis

Generally, the first step is to determine whether the Department will require preconstruction ambient air quality monitoring. Using an EPA-approved air quality model, the applicant must determine the predicted maximum ambient concentrations and compare the results with regulatory thresholds for preconstruction ambient monitoring, known as de minimis air quality levels. The regulations establish de minimis air quality levels for several PSD pollutants as shown in Table 9. For ozone, there is no de minimis air quality level because it is not emitted directly. However, since NO_2 and VOC are considered precursors for ozone formation, the applicant may be required to perform an ambient impact analysis (including the gathering of ambient air quality data) for any net increase of 100 tons per year or more of NO_2 or VOC emissions.

Table 9 - De Minimis Air Quality Levels

PSD Pollutant	*De Minimis Air Quality Levels*
CO	575 µg/m3, 8-hour average
NO_2	14 µg/m3, annual average;
PM_{10}	10 µg/m3, 24-hour average
SO_2	13 µg/m3, 24-hour average
Pb	0.1 µg/m3, 3-month average
Fl	0.25 µg/m3, 24-hour average
TRS	10 µg/m3, 1-hour average
H_2S	0.2 µg/m3, 1-hour average
RSC	10 µg/m3, 1-hour average
Hg	0.25 µg/m3, 24-hour average

If the predicted maximum ambient concentration is less than the corresponding de minimis air quality level, Rule 62-212.400(3)(e), F.A.C. exempts that pollutant from the preconstruction ambient monitoring analysis. If the predicted maximum ambient concentration is more than the corresponding de minimis air quality level (except for non-methane hydrocarbons), the applicant must provide an analysis of representative ambient air concentrations (pre-construction monitoring data) in the area of the project based on continuous air quality monitoring data for each such pollutant with an Ambient Air Quality Standard (AAQS). If no such standard exists, the analysis shall contain such air quality monitoring data as the Department determines is necessary to assess ambient air quality for that pollutant.

If preconstruction monitoring data is necessary, the Department may require the applicant to collect representative ambient monitoring data in specified locations prior to commencing construction on the project. Alternatively, the Department may allow the requirement for preconstruction monitoring data to be satisfied with data collected from the Department's extensive ambient monitoring network. Preconstruction monitoring data must meet the requirements of Appendix B to 40 CFR 58 during the operation of the monitoring stations. The preconstruction monitoring data will be used to determine the appropriate ambient background concentrations to support any required AAQS analysis.

Finally, after completing the project, the Department may require the applicant to conduct post-construction ambient monitoring to evaluate actual impacts from the project on air quality.

6.1.2. Source Impact Analysis

For each PSD-significant pollutant identified above, the applicant is required to conduct a source impact analysis for affected PSD Class I and Class II areas. This analysis is to determine if emissions from this project will significantly impact levels established for Class I and II areas. Class I areas include protected federal parks and national wilderness areas (NWA) that are under the protection of federal land managers. The Table 10 identifies the Class I areas located in Florida or that are within 200 km in nearby states. Class II areas represent all other areas in the vicinity of the facility open to public access that are not Class I areas.

Table 10 – Class I Areas in Florida or Within 200 km of the Facility

Class I Area	State	Federal Land Manger
Bradwell Bay NWA	Florida	U.S. Forest Service
Chassahowitzka NWA	Florida	U.S. Fish and Wildlife Service
Everglades National Park	Florida	National Park Service
Okefenokee NWA	Georgia	U.S. Fish and Wildlife Service
St. Marks NWA	Florida	U.S. Fish and Wildlife Service
Wolf Island NWA	Georgia	U.S. Fish and Wildlife Service

An initial significant impact analysis is conducted using the worst-case emissions scenario for each pollutant and corresponding averaging time. The regulations define separate significant impact levels for Class I and Class II areas for CO, NO_2, Pb, PM_{10} and SO_2. Based on the initial significant impact analysis, no additional modeling is required for any pollutant with a predicted ambient concentration less than the corresponding significant impact level. However, for any pollutant with a predicted ambient concentration exceeding the corresponding significant impact level, the applicant must conduct a full impact analysis. In addition to evaluating impacts caused by the project, a full impact modeling analysis also includes impacts from other nearby major sources (and any potentially-impacting minor sources within the radius of significant impact) as well to determine compliance with:

- The PSD increments and the federal air quality related values (AQRV) for Class I areas.
- The PSD increments and the AAQS for Class II areas.

As previously mentioned, for any net increase of 100 tons per year or more of VOC or NO_2 subject to PSD, the applicant may be required to perform an ambient impact analysis for ozone including the gathering of ambient ozone data.

6.1.3. PSD Class II Area Model

The EPA-approved American Meteorological Society and EPA Regulatory Model (AERMOD) dispersion model is used to evaluate short range impacts from the proposed project and other existing major sources. AERMOD version (09292) was used. In November of 2005, the EPA promulgated AERMOD as the preferred regulatory model for predicting pollutant concentrations within 50 kilometers of a source. The AERMOD model is a replacement for the Industrial Source Complex Short-Term model (ISCST3). The AERMOD model calculates hourly concentrations based on hourly meteorological data. The model can predict pollutant concentrations for annual, 24-hour, 8-hour, 3-hour and 1-hour averaging periods. AERMOD contains two input data processors, AERMET and AERMAP. AERMAP is the terrain processor and AERMET is the meteorological data processor. In addition to the PSD Class II modeling, it is also used to model the predicted impacts for comparison with the de minimis ambient air quality levels when determining preconstruction monitoring requirements.

For evaluating plume behavior within the building wake of structures, the AERMOD model incorporates the Plume Rise Enhancement (PRIME) downwash algorithm developed by the Electric Power Research Institute (EPRI). A series of specific model features recommended by the EPA are referred to as the regulatory options. The applicant used the EPA-recommended regulatory options in each modeling scenario and building downwash effects were evaluated for stacks below the good engineering practice (GEP) stack heights.

The AERMET meteorological data used in the AERMOD model consisted of a concurrent five-year period of hourly surface weather observations and twice-daily upper air soundings from the meteorological station in

Orlando. The five-year period of meteorological data was from 2006 through 2010. This station was selected for use in the evaluation because they are the closest primary weather stations to the project area and are most representative of the project site.

6.1.4. Stack Height Considerations

GEP stack height means the greater of 65 meters (213 feet) or the maximum nearby building height plus 1.5 times the building height or width, whichever is less. The calculated stack height for the proposed facility is less than GEP stack height. Therefore, the emissions have the potential to be influenced by aerodynamic downwash created by buildings that house the equipment. Therefore, building downwash was considered in the modeling analyses, as part of the PRIME downwash algorithm mentioned above.

6.1.5. Additional Impact Analysis

In addition to the above analyses, the applicant must provide an evaluation of impacts to: soils, vegetation, and wildlife; air quality related to general commercial, residential and industrial growth in the area that may result from the project. Additionally, the proposed project will be located 110 km from the closest portion of the nearest PSD Class I area, the Chassahowitzka NWA. Because the project is more than 50 km from the Class I area, a visibility impairment modeling analysis was not required.

6.2. PSD Significant Pollutants for the Project

The project will be located in Orange County, which is in an area that is currently in attainment with the AAQS or otherwise designated as unclassifiable. The site plan is shown on the next page. As discussed previously, the proposed project will increase emissions of CO and VOC in excess of the PSD significant emissions rates.

Major Stationary Sources Near the Proposed Modification of Seminole Electric

To provide some perspective on the relative scale of the proposed project modification, the Tables 11 and 12 identify the largest stationary source of CO and VOC in and around Orange County. The potential annual emissions from the project are shown for comparison with actual emissions from the existing facilities.

Table 11 - Largest Sources of CO (2010) Nearest to the Proposed Facility

Owner/Company Name	Site Name	County	Emission, TPY
Orlando Utilities Commission	Stanton Energy Center	Orange	1,748
Cutrale Citrus Juices USA	Auburndale Plant	Polk	984
Lakeland Electric	Mcintosh Power Plant	Polk	642
Wheelabrator Ridge Energy	Ridge Generating Station	Polk	502
Florida Power Corp. Energy	Hines Energy Complex	Polk	446
Calpine Construction Finance Co	Osprey Energy Center	Polk	442
Citrosuco North America	Citrosuco North America	Polk	398
Cutrale Citrus Juices USA	Leesburg Plant	Lake	331
Citrus World	Citrus World	Polk	248
Harvest Energy	**Harvest Energy**	**Orange**	**228**
Bartow Citrus Products	Bartow Citrus Products	Polk	197
Auburndale Power Partners	Auburndale Power Partners	Polk	174
Tampa Electric Company	Polk Power Station	Polk	139
Florida Power Corporation	Intercession City Plant	Osceola	121
Walt Disney World	Walt Disney World Resort	Orange	87

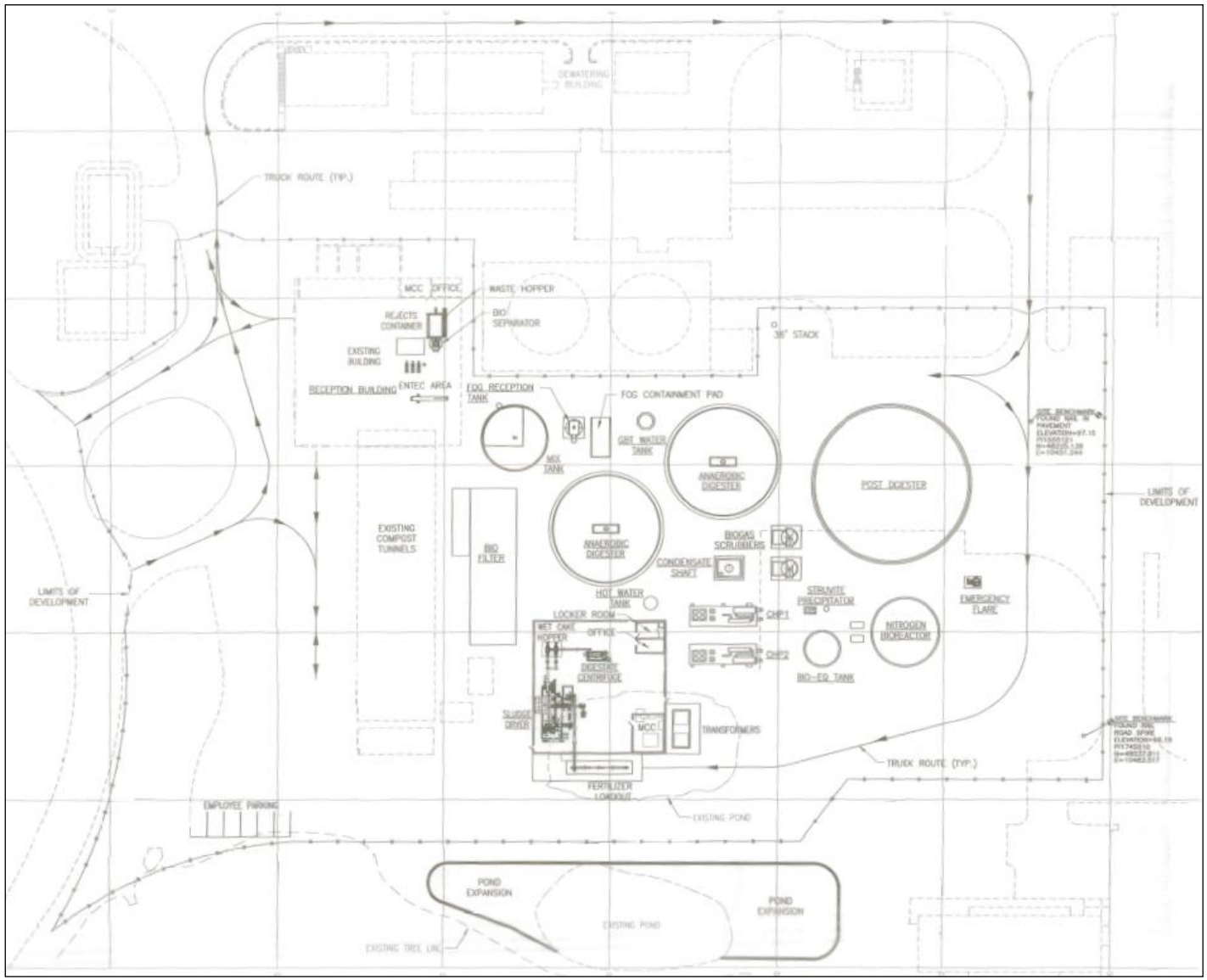


Figure 5 – Harvest Energy Site Plan

Table 12 - Largest Sources of VOC (2010) Nearest to the Proposed Facility

Owner/Company Name	Site Name	County	Emission, TPY
Cutrale Citrus Juices USA	Auburndale Plant	Polk	561
Citrus World	Citrus World	Polk	516
Citrosuco North America	Citrosuco North America	Polk	430
Cutrale Citrus Juices USA	Leesburg Plant	Lake	193
Bartow Citrus Products	Bartow Citrus Products	Polk	163
Industrial Container Service	Industrial Container Service	Polk	118
Carpenter Co Insulation Division	Carpenter Co Insulation Division	Polk	115
Keymark Corp of Florida	Lakeland Plant	Polk	111
Carlisle Construction Materials	Insulfoam	Polk	95
Cellofoam North America	Cellofoam North America	Orange	93
Calpine Construction Finance Co	Osprey Energy Center	Polk	85
Spiralkote Flexible Packaging	Spiralkote Flexible Packaging	Orange	78
Orlando Utilities Commission	Stanton Energy Center	Orange	67
Toufayan Bakeries of Florida	Toufayan Bakeries	Orange	67
Harvest Energy	**Harvest Energy**	**Orange**	**65**
Greif Packaging	Greif Packaging	Polk	64
Correct Craft, Inc	Correct Craft, Inc	Orange	63

6.3. Preconstruction Ambient Monitoring Analysis

Using the AERMOD model, the applicant predicted the following maximum ambient impacts for CO (see Table 13) from the project.

Table 13 - De Minimus Air Quality Levels

Pollutant	Averaging Time	Maximum Predicted Impact (µg/m^3)	De Minimis Concentration (µg/m^3)	Greater than De Minimis?
CO	8-hr	347	575	No

As shown above, CO is exempt from preconstruction monitoring because the predicted impact is less than the de minimis level. Nevertheless, the Department and its partners (local air pollution control programs) maintain an extensive quality-assured ambient monitoring network throughout the state. As Figures 6 and 7 indicate, the ambient air monitoring sites are concentrated in areas of high population density, along the coasts and near major highways in the interior portion of the state.

These monitors can be used to estimate the existing air quality in the area of the proposed facility. Table 14 summarizes CO and ozone ambient data from 2011 available for existing nearby monitoring locations. The existing monitoring data show no violations of any ambient air quality standards. The Department determines that the data collected from these monitors is representative of the air quality in the vicinity of the project. As necessary, the above ambient concentrations would be suitable for use as the ambient background concentrations for any required AAQS analysis.

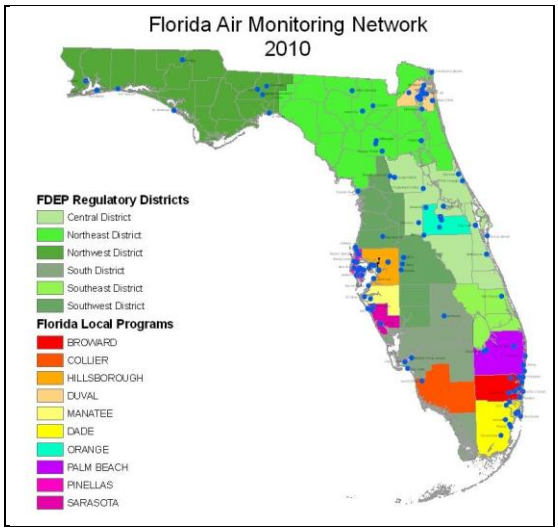


Figure 6 - Florida Air Monitoring Network

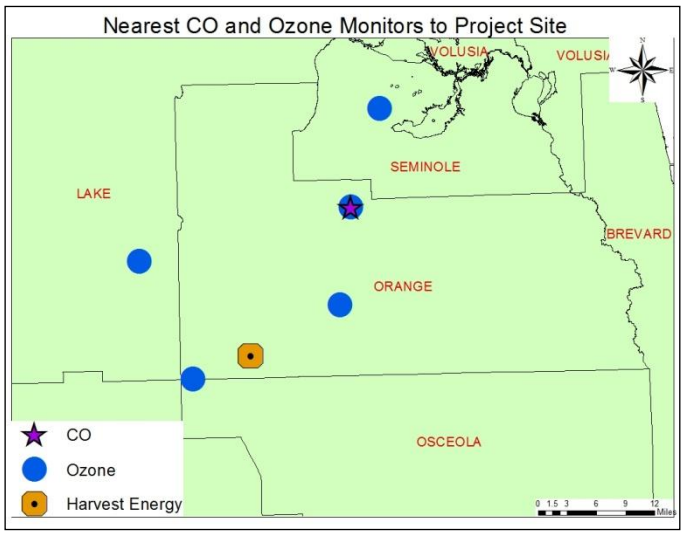


Figure 7 – Nearest CO and Ozone Monitors to Site

Table 14 - Representative Ambient Concentrations

Pollutant	Averaging Time	2011 Ambient Concentration	Monitor Location
CO	8-hour	1.4 ppm	Winter Park
	1-hour	2.6 ppm	
Ozone	8-hour	0.071 ppm	Winegard
	1-hour	0.071 ppm	

The Winter Park CO monitor is closest to and most representative of the ambient air quality at the proposed Harvest Energy project location. The Winegard ozone monitor is located 17 km to the northeast and is sufficient for background values at the proposed site.

6.4. Affected PSD Class I Areas

Table 15 identifies the closest affected Class I area as well as the distance to the facility and the number of receptors used in the modeling analysis. For the preliminary significant impact analysis, the highest short-term predicted concentrations will be compared to the significant impact levels (SIL). Results from the SIL modeling demonstration indicate that maximum ambient air CO impacts are less than the SIL. For this reason, combined with the large distance to the nearest Class I area, a Class I ambient air impact analysis was not performed for the proposed CO emission rate increase.

Table 15 - Source Impact Analysis for Closest PSD Class I Area

PSD Class I Area	Distance	Receptors
Chassahowitzka NWR (ONWR)	110 km	---

6.5. Source Impact Analysis for PSD Class II Areas

For the preliminary significant impact analysis, the 2nd highest short-term predicted concentrations will be compared to the respective significant impact levels. Since five years of data are available, the highest-second-high (HSH) short-term predicted concentrations will be used for any required AAQS and PSD Class II increment

analysis with regard to short-term averages. However, for annual averages, the highest predicted annual average will be compared with the corresponding annual level.

6.5.1. Receptor Grid

A combination of fence line, near-field and far-field receptors were chosen for predicting maximum concentrations in the vicinity of the project. The fence line receptors consisted of 21 discrete Cartesian receptors around the facility fence line. The remaining receptor grid consisted of densely spaced discrete Cartesian receptors at 100 meters apart starting at the property line and extending to 5 kilometers.

6.5.2. Results of the Significant Impact Analysis

Table 16 shows the results of the preliminary PSD Class II significant impact analysis.

Table 16 - Significant Impact Analysis for PSD Class II Areas (Vicinity of Facility)

Pollutant	Averaging Time	Maximum Predicted Impact (µg/m^3)	Significant Impact Level (µg/m^3)	Significant Impact?	Radius of Significant Impact (km)
CO	8-hr	347	500	NO	NONE
	1-hr	549	2,000	NO	NONE

As shown above, the predicted impacts of CO are well below the corresponding PSD Class II significant impact level and no further analysis is required. Also, because no increments exist for any averaging period of CO, an increment analysis was not performed.

6.6. Ozone Modeling

Projects with VOC and NO_X emissions greater than 100 TPY are required to perform an ambient impact analysis for ozone including the gathering of preconstruction ambient air quality data. However, the estimated annual potential VOC and NOx emissions from the project are 63 TPY and 39 TPY, respectively. Therefore, this type of analysis is not required. However, for informational purposes, Table 17 shows that the area is currently in attainment with the 8 hour ozone standard. The ozone monitoring data at Orange County is only approximately 17 km northwest of the proposed project site and is sufficient for the purposes of background values at the proposed site.

Table 17 – Ozone Background Compared to NAAQS

Baker Co Monitor Value (ppm)	8-hour Ozone NAAQS	Percent of NAAQS
0.071	0.075	95%

6.7. Impact on Soils, Vegetation, and Wildlife

Because emissions from the proposed Harvest Energy project do not trigger PSD review for SO_2, $PM/PM_{10}/PM_{2.5}$, or NOx, impacts upon soils, vegetation and wildlife will be negligible.

6.8. Impact on Visibility

Because emissions from the proposed Harvest Energy project do not trigger PSD review for SO_2, NO_X, or condensable and fine particulate precursors, the project will not cause or contribute to regional haze issue.

6.9. Conclusion on Air Quality Impacts

As described in this report and based on the required ambient impact analyses, the Department has reasonable assurance that the proposed project will not cause, or significantly contribute to, a violation of any AAQS or PSD increment.

7. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the Draft Permit. This determination is based on a technical review of the complete application, reasonable assurances provided by the applicant, and the conditions specified in the Draft Permit. David Read is the project engineer responsible for reviewing the application and drafting the permit changes. Melody Lovin is the meteorologist responsible for reviewing and approving the ambient air quality analyses. Additional details of this analysis may be obtained by contacting the project engineer at the Department's Office of Permitting and Compliance at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.