TECHNICAL EVALUATION

&

PRELIMINARY DETERMINATION

APPLICANT

U.S. EcoGen Polk, LLC (US EcoGen)
601 Heritage Drive, Suite 127
Jupiter, Florida 33458

U.S. EcoGen Polk Generating Facility
ARMS Facility ID No. 1050444

PROJECT

Project No. 1050444-002-AC
Update Power Island Rating

COUNTY

Polk County, Florida

PERMITTING AUTHORITY

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

March 18, 2014

1. APPLICATION INFORMATION

1.1. Applicant Name and Address

U.S. EcoGen Polk, LLC (US EcoGen)
601 Heritage Drive, Suite 127
Jupiter, Florida 33458

Authorized Representative: Mr. William F. Quinn, P.E., President

1.2. Facility Location

The proposed US EcoGen Biomass Generating Facility will be located in Polk County on a 1,163-acre parcel in the City of Fort Meade off of U.S. Highway 17. The actual address of the facility is County Road (CR) 630, Fort Meade in Polk County, Florida. The location of Polk County is shown in **Figure 1**. The location of the plant in relationship to U.S. Highway 17 is shown in **Figure 2** with a close up in of the facility provided in **Figure 3**. The Duke Energy Florida Hines Facility cooling water ponds are visible to the northwest.

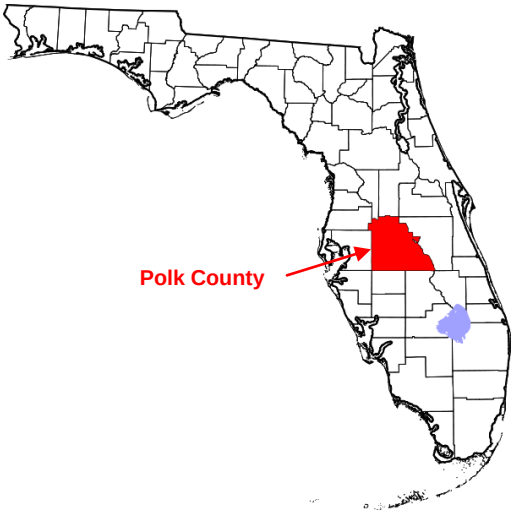

Figure 1. Polk County, Florida.

Figure 2. US EcoGen Site in Relation to U.S. Highway 17.

Figure 3. Close Up Aerial View of Site.

2. PROPOSED PROJECT

2.1. Project Description

The applicant proposal to construct a woody biomass electric power plant called the US EcoGen facility was originally approved under a minor air construction permit (No. 1050444-001-AC) that was issued by the Department in July 2012. US EcoGen has since updated the details of the project's power island, including the biomass boiler to reflect the latest engineering design. Specifically, US EcoGen plans to build a bubbling fluidized bed (BFB) biomass boiler rated at 860 million Btu per hour (MMBtu/hour) instead of 740 MMBtu/hour. After the heat input increase, the steam electrical power capacity of the power island will be rated at less than 75 megawatts (MW, gross). The applicant has also requested other minor changes to the permit to reflect the most recent engineering design. These changes are listed below:

- The selective catalytic reduction (SCR) system used to control nitrogen oxides (NO_X) emissions may now consist of injecting ammonia into both the boiler furnace via a selective non-catalytic reduction (SNCR) system in conjunction with the SCR system (a SCR system must still be installed);
- The maximum steam production from the boiler will increase from 565,000 pounds per hour (lb/hr) to 660,000 lb/hr which reflects the increase in heat input to the boiler;
- The description of the spray dryer absorber (SDA) system used to control acid gas emissions from the boiler will be updated;
- The permit will indicate that aqueous ammonium sulfate in a 40% concentration may be used as a corrosion reduction agent and to provide additional NO_X reduction in the boiler furnace via a SNCR system. If used, the ammonium sulfate will be stored on-site in a 10,000 gallon tank; and
- Minor changes will be made to the description of the ash (fly and bottom) handling, storage and shipment emission unit.

The following is a link to the US EcoGen permit application: US EcoGen Application

The power plant will be comprised of four major process areas consisting of:

- Clean woody biomass receiving, handling, storage and processing;
- Power Island, including a BFB boiler and steam turbine electrical generator (STEG), an aqueous ammonia storage tank, a sand storage silo, an air cooled condenser and an auxiliary cooling tower (Note: A 10,000 gallon ammonium sulfate storage tank may also be installed);
- Ash (fly and bottom) handling, storage and shipment including a fly ash storage silo; and
- Emergency support equipment consisting of an emergency generator and fire water pump.

Table 1 is a list of the Emissions Units (EU) that still comprise this project.

TABLE 1 – LIST OF EMISSIONS UNITS FOR THE US ECOGEN POLK COUNTY BIOMASS GENERATING FACILITY.

EU No.	Emission Unit Description
001	Fuel Receiving, Handling, Storage and Processing
002	Power Island
003	Ash Handling, Storage and Shipment
004/005	Emergency Equipment

Additional details of the originally permitted US EcoGen project, including the final permit and the original Technical Evaluation and Preliminary Determination (TEPD) document, can be found at the following webpage: US EcoGen Project

3. AIR POLLUTION REGULATIONS AND APPLICABILITY DETERMINATIONS

3.1. Department Regulations

Projects at stationary sources with the potential to emit air pollution are subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The statutes authorize the Department of Environmental Protection (Department) to establish regulations regarding air quality as part of the Florida Administrative Code (F.A.C.), which includes the following applicable chapters shown in **Table 2** below.

TABLE 2 – POTENTIAL APPLICABLE RULES FROM THE FLORIDA ADMINISTRATIVE CODE (F.A.C.).

Chapter	Description
62-4	Permits
62-17	Power Plant Siting (not applicable as project is less than 75 MW)
62-204	Air Pollution Control – General Provisions
62-210	Stationary Sources of Air Pollution – General Requirements
62-212	Stationary Sources – Preconstruction Review
62-213	Operation Permits for Major Sources (Title V) of Air Pollution
62-214	Requirements for Sources Subject to the Federal (Title IV) Acid Rain Program
62-296	Stationary Sources – Emission Standards
62-297	Stationary Sources – Emissions Monitoring

3.2. Federal Regulations

The U.S. Environmental Protection Agency (EPA) establishes air quality regulations in Title 40, Code of Federal Regulations, Part 60 (40 CFR 60) that identifies New Source Performance Standards (NSPS) for a variety of industrial activities. 40 CFR 61 specifies National Emission Standards for Hazardous Air Pollutants (NESHAP). 40 CFR 63 specifies NESHAP provisions based on the Maximum Achievable Control Technology (MACT) for given source categories.

Federal regulations adopted by reference are given in Rule 62-204.800, F.A.C. State regulations approved by EPA are given in 40 CFR 52, Subpart K – Florida; also known as the State Implementation Plan (SIP) for Florida.

3.3. General PSD Major Stationary Source 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.

Commonly addressed PSD pollutants in the power industry include: carbon monoxide (CO), NO_X, particulate matter (PM), PM smaller than 10 micrometers (µm) (PM_{10}), PM smaller than 2.5 µm ($PM_{2.5}$), sulfur dioxide (SO_2), volatile organic compounds (VOC), sulfuric acid mist (SAM), lead (Pb), fluorides (F) and mercury (Hg).

Additional PSD pollutants that are more common to certain other industries include: hydrogen sulfide (H_2S), total reduced sulfur (TRS) including hydrogen sulfide (H_2S), reduced sulfur compounds (RSC) including H_2S, municipal waste combustor (MWC) organics measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans (dioxin/furan), MWC metals measured as PM; MWC acid gases measured as SO_2 and HCl, and municipal solid waste (MSW) landfill emissions as non-methane organic compounds (NMOC).

As defined in Rule 62-210.200(Definitions), F.A.C., a stationary source is a "major stationary source" (major PSD source) if it emits or has the potential to emit (PTE):

- 250 tons per year (tons/year) or more of any PSD pollutant; or
- 100 tons/year or more of any PSD pollutant and the facility belongs to one of the 28 listed PSD major facility categories.

The list given in the citation includes the category of "**fossil** fuel-fired steam electric plants of more than 250 MMBtu/hour heat input". However the US EcoGen project will not use more than 250 MMBtu of fossil fuel (natural gas) as it will rely almost entirely on biomass. The maximum design rate to the BFB biomass boiler using natural gas alone is 160 MMBtu/hr. Biomass-fueled steam electric plants are not included among the 28 listed PSD major facility categories. Therefore, to be considered a major stationary source the project would have to emit or have the potential to emit 250 tons/year or more of at least one PSD pollutant.

4. DEPARTMENT'S ANALYSIS

4.1. PSD Applicability of Modified Project

US EcoGen has agreed to reduce the emissions from the biomass boiler on a pounds per MMBtu (lb/MMBtu) basis to stay below the 250 TPY threshold so that the facility is not a major stationary source with regard to PSD pollutants. The emission limits for the BFB biomass boiler in the original final permit are shown in **Table 3** below. No emissions limits will be changed in the updated permit. As seen from this table, the pollutants of most concern are NO_X, CO and SO_2 which are closest the 250 TPY threshold. The other criteria pollutants (PM and VOC) are well below the threshold even when the heat input to the boiler is increased by 16.2%. For example, PM emissions could potentially increase from 97.2 TPY to 114 TPY (see footnote 3 in **Table 3**) which is still well below the 250 TPY threshold. However, the Department actually believes that PM emissions will be much less than the 97.2 TPY value as discussed in **subsection 5.2** below. Visible Emission (VE) will not be effected by the heat input increase. Hydrogen Chloride (HCl) which is a hazardous air pollutant (HAP) will be addressed in the next subsection.

To stay below the 250 TPY PSD major source threshold for NO_X, CO and SO_2, emissions levels will be reduced to account for the 16.2% heat input rate increase to the boiler. Since compliance with the current emissions limits for these three pollutants is by continuous emissions monitoring systems (CEMS), the Department will have reasonable assurance that the 250 TPY threshold will not be exceeded so long as the emissions of these pollutants from the boiler do not exceed 0.065 lb/MMBtu (equivalent to 55.9 pounds per hour (lb/hr)) on a 12-month rolling average, rolled monthly basis. US EcoGen has agreed to this requirement and consequently the TPY limits for these pollutants will not be changed from the originally permitted limits.

TABLE 3 – ORIGINAL EMISSION LIMITS FOR US ECOGEN BIOMASS BOILER.

Pollutant	Emission Standard	Basis	Compliance Demonstration
NO_X [1]	0.30 lbs/MMBtu	NSPS Db 40 CFR 60.44b Avoid PSD Rule 62-212.400(12), F.A.C.	30-day rolling average, rolled daily compliance by CEMS
	246 TPY	Avoid PSD Rule 62-212.400(12), F.A.C.	12-month rolling average, rolled monthly, compliance by CEMS
CO	246 TPY	Avoid PSD Rule 62-212.400(12), F.A.C.	12-month rolling average, rolled monthly, compliance by CEMS

Pollutant	Emission Standard	Basis	Compliance Demonstration
SO_2	227 TPY [2]	Avoid PSD Rule 62-212.400(12), F.A.C.	12-month rolling average, rolled monthly, compliance by CEMS
PM [3, 7]	0.03 lbs/MMBtu (filterable only)	NESHAP JJJJJJ NSPS Db 60.43b(h)(1) Avoid PSD Rule 62-212.400(12), F.A.C.	Initial and Annual Stack Test
VE[4]	10% average, daily block	NESHAP JJJJJJ, Reasonable Assurance[4]	Compliance by COMS
	20% (27%), one 6-minute block/hour	NSPS Subpart Db	
HCl	9.9 TPY	Avoids Major HAP Status [5]	Initial and Annual Stack Test, Performance Curves [6]

1. NO_X limit in pounds per million Btu heat input (lb/MMBtu) on a 30-day basis is pursuant to NSPS Subpart Db applicable to units that combust wood with very low sulfur natural gas. Mass rate limit in TPY insures annual emissions will be less than 250 TPY and avoids PSD.
2. Use of low sulfur fuels including wood and natural gas insure that uncontrolled SO_2 emissions are less than 0.32 lb/MMBtu. Therefore, no specific limit from NSPS Subpart Db applies. Compliance with this exemption is by fuel monitoring. Mass rate limit in TPY insures annual emissions will be less than 250 TPY.
3. Meeting the NSPS and NESHAP PM limits equals approximately 97.2 TPY. Meeting these limits will provide reasonable assurance that annual emissions of $PM/PM_{10}/PM_{2.5}$ (including condensable) will be less than 250 TPY.
4. VE by continuous opacity monitoring system (COMS). VE standard of 10% opacity per NESHAP Subpart JJJJJJ. VE must meet 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent to meet NSPS Subpart Db requirements. Meeting the Subpart Db requirements ensure meeting the VE requirements of Rules 62-296.320 and 62-296.406, F.A.C. The permittee must meet the work practice standard requirements of the NESHAP JJJJJJ during periods of startup, shutdown and malfunction. A work practice standards plan to minimize emissions during these periods shall be submitted to the Compliance Authority for approval no later than 180 days prior to boiler startup. Opacity of 10% provides reasonable assurance of continuous compliance with PM/PM_{10} and is a reasonable expectation given catalyst-based NO_X, CO, VOC controls.
5. Must stay below 10 TPY threshold for an individual HAP to avoid becoming a major source of HAP and triggering NESHAP Subpart DDDDD - Major Sources: Industrial, Commercial, and Institutional Boilers.
6. Performance curves in conjunction with annual stacking testing to determine suitable sorbent injection rates show compliance with the 9.9 TPY emission cap.
7. Compliance with this PM limit ensures compliance with Rule 62-296.410, F.A.C. and 62-296.406, F.A.C.

Based on the analysis given in the preceding paragraphs, the Department has reasonable assurance that the US EcoGen facility will still remain a minor air pollution source with regard to the PSD program after the boiler heat input rate increase. No change in any emission limits given in **Table 3** will occur as a result of this project. Consequently, no change in the compliance methods for these pollutants will be required.

4.2. Major Source of Hazardous Air Pollutants Determination for Modified Project

Estimates by US EcoGen of individual key HAP emissions from the original project are provided in **Table 4**. Only individual HAP emissions greater than 0.10 TPY are listed with all others grouped into the "other HAP" category.

TABLE 4 - ESTIMATED EMISSIONS OF KEY HAP (TPY).

Pollutant [1]	HCl	HF	Mn	Cl_2	C_6H_{14}	C_2H_4O	C_6H_5Cl	C_8H_{10}
Emissions	9.9	0.16	0.65	0.99	1.2	0.15	0.11	0.10

Pollutant [2]	Pb	C_6H_6O	C_3H_6O	C_8H_8	Other HAP	Total
Emissions	0.60	0.17	0.20	6.2	0.67	**21.1**

1. HF is hydrogen fluoride; Mn is manganese; Cl_2 is chlorine; C_6H_{14} is hexane; C_2H_4O is acetaldehyde; C_6H_5Cl is chlorobenzene; and C_8H_{10} is ethylbenzene.
2. C_6H_6O is phenol; C_3H_6O is propionaldehyde; and C_8H_8 is styrene.

The Department regulates major sources of HAP in accordance with applicable portions of 40 CFR 63 adopted in Rule 62-204.800(11), F.A.C. To be a major source of HAP, the US EcoGen plant will have to have the potential to emit a single HAP at a rate equal to or greater than 10 TPY or aggregated HAP at a rate equal to or greater than 25 TPY. As seen from **Table 4**, previously with a boiler heat input of 740 MMBtu/hr, the US EcoGen facility was not a major source of HAP. Instead, the US EcoGen facility was an area source of HAP and consequently the BFB biomass boiler was subject to 40 CFR 63, subpart JJJJJJ - National Emission Standards for Hazardous Air Pollutants (NESHAP) for Industrial, Commercial, and Institutional Boilers Area Sources. If the US EcoGen facility is a major source of HAP, the biomass boiler would be subject to 40 CFR 63, subpart DDDDD - NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters.

With a 16.2% increase in boiler heat input (740 MMBtu/hr versus 860 MMBtu/hr), the total HAP emissions from the US EcoGen facility could potentially increase from 21.1 TPY to 24.51 TPY which is still below the aggregated major source HAP threshold of 25 tons/year. However, this is a very conservative estimate since it is scaling up HAP emissions from the entire facility by 16.2% and not just the biomass boiler. Finally, as will be discussed in more detail below, the Department believes that actual HAP emissions will be much lower than the potential HAP emission estimates given in **Table 4**.

The individual HAP of concern from **Table 4** is HCl an acid gas HAP which has a yearly emissions rate of 9.9 TPY. This rate is just below the 10 TPY major source HAP threshold. HCl emissions are solely from the biomass boiler at the US EcoGen facility. With a 16.2% increase in boiler heat input, the 9.9 TPY of HCl could potentially increase to 11.5 TPY with no changes to the acid gas pollution controls on the boiler or the biomass feedstock used as fuel in the boiler. However, the 9.9 TPY HCl emission limit will not be changed as a result of this project. US EcoGen will still be required to meet the 9.9 TPY HCl limit.

US EcoGen originally proposed to control acid gases in general and SO_2 and HCl in particular by the use of a lime spray dryer absorber (SDA) system or a dry sorbent injection (DSI) system utilizing the sodium bicarbonate ($NaHCO_3$). The sorbent will be captured in particulate form by a baghouse. The baghouse will also provide additional acid gas control due to the inherent alkalinity of the fly ash from the combustion of biomass fuels that is also captured in the baghouse as a cake on the bags.

Currently, annual stack testing along with sorbent injection performance curves are required to show compliance with the yearly HCl emission limit of 9.9 TPY. The injection rate of lime or sodium bicarbonate in the SDI or SDA systems, respectively, could be increased to control HCl emissions below the 10 TPY major source HAP threshold. However, there is additional data available (see **Table 5**) that provides reasonable assurance to the Department that actual HCl emissions from the US EcoGen biomass boiler will be well below 10 TPY.

TABLE 5 – INITIAL COMPLIANCE TEST RESULTS FROM A 116 MW (GROSS) BIOMASS BOILER SIMILAR TO THE US ECOGEN BOILER.

Parameter	3 Run Average Emission	Permitted Emissions Rate
Nitrogen oxides	0.052 lb/MMBtu	0.070 lb/MMBtu
Sulfur dioxide	0.000 lb/MMBtu	0.029 lb/MMBtu
Sulfuric acid mist (SAM)	0.1 lb/hr	1.4 lb/hr

Parameter		3 Run Average Emission	Permitted Emissions Rate
Carbon monoxide		0.02 lb/MMBtu	0.08 lb/MMBtu
HCl		0.04 lb/hr	2.22 lb/hr
Hydrogen Fluoride (HF)		0.04 lb/hr	2.22 lb/hr
Total Filterable Particulate Matter (PM_f)		0.001 lb/MMBtu	0.015 lb/MMBtu
Condensable Particulate Matter (PM_c)		0.001 lb/MMBtu	No set limit.
Visible Emissions (VE)		0.00%	10% Opacity
Total Hydrocarbons (VOC)		0.003 lb/MMBtu	0.009 lb/MMBtu
Ammonia slip (NH_3)		0.7 ppmvd @ 7% O2	10 ppmvd @ 7% O_2
Mercury (Hg)		3.2×10^{-7} lb/MMBtu	8.0×10^{-7} lb/MMBtu
Chromium, Lead, Manganese and Phosphorus (metal HAP)		3.87 TPY	Sum of HCl, HF, Organic HAP and Metal HAP shall not exceed 24.7 tons per year (TPY)
acrolein, benzene, xylene isomers plus ethyl benzene, methylene chloride, methyl chloroform and toluene	Organic HAP		
formaldehyde and acetaldehyde			
PAH/POM			

Table 5 shows initial compliance test results from a 116 MW (gross) biomass boiler from the year 2013. This boiler has a fuel slate similar to the US EcoGen boiler. In addition, the 116 MW boiler is also a BFB design and has similar pollution control technologies, including acid gas controls and a baghouse. As seen from the highlighted portion of the table, HCl emissions are well below the permitted limit of 2.22 pounds per hr (lb/hr). In fact, on a yearly basis, HCl emissions from the 116 MW boiler equate to only 0.18 TPY. The US EcoGen boiler after this permit modification will have a capacity less than 75 MW (gross). Prorating the 116 MW boiler's HCl emissions to the US EcoGen boiler indicates yearly emissions of HCl of 0.12 TPY. Even if there are small differences between the two boilers, including biomass fuels and pollution controls, it is reasonable to infer that HCl emissions from the US EcoGen boiler will be well below the permitted level of 9.9 TPY even if the lime or sodium bicarbonate injection rates are not increased.

Further assurance for the above assertion with regard to the HCl emissions rate is the fact that SO_2 emissions from the 116 MW boiler (also highlighted in **Table 5**) are zero which indicates that the biomass feedstock is low in sulfur and that the acid gas air pollution control system along with the alkalinity of the biomass fly ash in conjunction with a baghouse are highly effective. Finally, it should be noted that all other pollutant emissions (NO_X, SAM, CO, HF, PM_f, VE, VOC, NH_3, Hg, metal HAP and organic HAP) from the 116 MW boiler are well below their permitted limits. This indicates that the original emissions estimates were conservative in nature. In all likelihood, the same conservatism holds true for the US EcoGen boiler with regard to permitted emission limits, and will be verified based on CEMS and stack test results.

Based upon the analysis given in the preceding paragraphs, the Department has reasonable assurance that even after the requested heat input increase to the US EcoGen boiler that the proposed acid gas controls along with the alkalinity of the fly ash in conjunction with a baghouse and the conservative nature of the

original HCl emissions rate estimate will keep HCl emissions well below the 10 TPY major source HAP threshold. Consequently, the permit will continue to have an HCl emission rate limit of 9.9 TPY with compliance shown by annual stack tests along with sorbent injection performance curves.

4.3. Other Permit Changes

Along with the heat input increase and the corresponding electrical power output from the power island, several other minor changes to the original US EcoGen the permit with regard to the power island (EU 002) will be made. The description of the SCR system will be modified to reflect that it may be used in combination with an SNCR system. Further, steam production will be increased to reflect that the boiler heat input rate increased and the description of the acid gas pollution control system will be modified to reflect the most recent engineering design. Finally, the description of the SCR system will be modified to indicate that aqueous ammonia sulfate in a 40% concentration will be used as a corrosion reduction agent and to support NO_X reduction in the boiler furnace if US EcoGen elects to use an SNCR system in combination with a SCR system. All other operational limitations, including fossil fuel limits along with emission limits and reporting, testing and recordkeeping requirements will be unchanged for the power island.

The only other emission unit effected by the permit modification is the ash (fly and bottom) handling, storage and shipment emission unit (EU 003). Descriptive language for this emission unit will be modified to reflect the latest engineering design. No emission increase of PM will result from these minor changes.

5. AMBIENT AIR QUALITY

Since no emissions limits are changing as a result of this project, a PSD preconstruction review is not triggered. Consequently an air dispersion modeling analysis is not required. However, even though the original project did not trigger PSD, the applicant did provide an air dispersion modeling analysis to ensure that the project did not cause or contribute to a violation of a National Ambient Air Quality Standard (NAAQS). Since the updated project is not expected to increase the actual mass emission rates (lb/hr) of NO_X, SO_2 and CO in order to comply with the corresponding emissions caps and actual PM emissions will likely be much less than the permitted limit (see **subsection 4.2**), the original air quality modeling analysis is still valid. The original analysis demonstrated that the sum of ground-level concentrations of nitrogen dioxide (NO_2), PM_{10}, CO and SO_2 caused by the project and background concentrations were much less than the respective NAAQS.

6. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed US EcoGen, Polk Project modification 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, the draft emissions standards determinations, review of the previous air quality impact analysis, and the conditions specified in the draft permit.

David L. Read, P.E.is the engineer responsible preparing the technical evaluation. He may be contacted at David.Read@dep.state.fl.us and 850-717-9075. Mr. A.A. Linero, P.E. is the engineer responsible for preparing the draft permit. He may be contacted at Alvaro.Linero@dep.state.fl.us and 850-717-9076.