EPA Information Request
Invenergy Thermal Development LLC – Ector County Energy Center
Application for Greenhouse Gas Prevention of Significant Deterioration Permit

1. Please provide a copy of the State/PSD/Nonattainment application that was submitted to TCEQ.

   A copy of the State/PSD application, which was submitted to the TCEQ on 13 May, 2013, is attached to this document in Appendix A.

2. The permit application discusses the use of an evaporative cooling system. Please specify if this is a wet or dry evaporative cooling system. Please provide a specific evaluation of the commercial systems available for cooling of inlet air to a combustion turbine and discuss and provide a justification for the cooling system selected.

   The plant will install a wet evaporative cooling system that utilizes trickling media.

   There are three primary technologies for conditioning gas turbine inlet air:

   - Evaporative cooling (with trickling media)
   - Inlet fogging
   - Mechanical cooling

   Evaporative cooling using trickling media is the simplest, lowest capital cost, and least maintenance intensive option currently available to provide gas turbine inlet air conditioning for this project. The technology relies on having a continuous supply of water to the top of the evaporative cooler media, which is installed in the gas turbine air inlet filter house. Carry over potential is minimal and there is virtually no process control necessary while in operation. The evaporative cooler will be manually enabled by the plant operator when the environmental conditions are suitable for the evaporative cooler to increase turbine output. Once the proper inlet guide vane angles and compressor inlet temperatures are met, the plant operator will start the process. The process requires a small amount of makeup water and has a limited parasitic load. Although not required for the project, Invenergy feels evaporative cooling would be an effective way to increase the production capabilities of the unit, given the low ambient relative humidity in the area. Evaporative cooling provides the greatest benefit for a nominal capital and operating cost investment, on the proposed project.

   Inlet fogging involves injecting water directly into the air inlet of the gas turbine. While this technology delivers increased efficiency and temperature reduction (on-par with the evaporative cooling with trickling media) at a low capital and operating cost, it was not considered for the project due to the fact that it is difficult to control and greatly increases the risk of water droplet erosion and ice formation at the inlet bell of the gas turbine.

   Mechanical cooling involves the circulation of chilled water through a series of cooling coils in the gas turbine air inlet filter house. The chilled water is typically produced by a centrifugal chiller (or absorption chiller, if steam is available). The system requires a heat exchange device such as a cooling tower or large fin fan coolers in order to dissipate the heat removed from the intake air. Variations of the mechanical cooling arrangement can include thermal storage or other means to minimize operating cost. This technology carries the highest initial capital cost ($/kW) and the highest operating cost (parasitic load + O&M).

Since evaporative cooling is more effective at low ambient humidity levels at lowering the intake air temperature, evaporative cooling is more appropriate for areas where high ambient temperatures coincide with low ambient relative humidity. For areas where high ambient temperatures are typically coincidental with high ambient humidity, mechanical cooling is more suitable. Based on the location of the proposed facility and the performance of lower cost alternate systems such as evaporative cooling, mechanical cooling is not financially viable for this project.

Invenergy has only installed evaporative cooling on its current projects and is well versed in the operational and maintenance characteristics of this technology. Evaporative cooling has proven to be a simple, reliable, and low cost boost to Invenergy's generators throughout the country.

3. Please include a discussion of the natural gas line and electrical transmission infrastructure in proximity to the ECEC. Will new natural gas lines or electrical transmission lines need to be constructed as a part of this project? Please provide a map of any new pipelines and electrical transmission lines.

The ECEC will require up to approximately 5 miles of new natural gas lateral pipeline to connect the proposed plant to an existing interstate pipeline. The gas supply for the project has not been finalized, therefore Invenergy has performed a cultural and biological assessment of 3 different gas pipeline corridors (depicted in green in Figure 1 below) that may be used by the project. In addition to the gas lateral, 0.5 miles of 138kV transmission line (depicted in blue in Figure 1 below) will be constructed to connect the project to the Holt Substation. This transmission line will exit the plant from the south and enter the eastern edge of the Holt substation.

All gas and transmission paths, depicted in Figure 1 below, were studied in the Biological Assessment and Cultural Resources Assessment which were included with the GHG PSD Permit application.

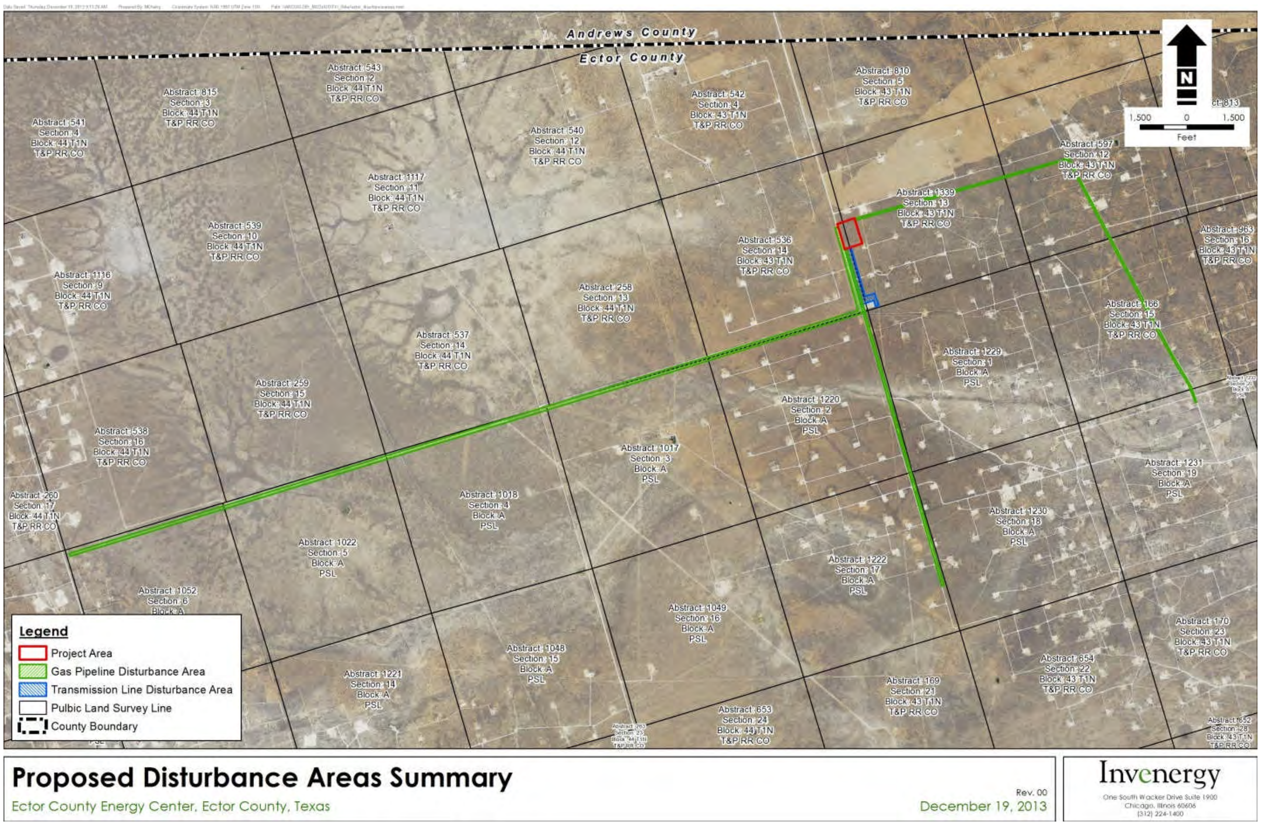

FIGURE 1 – Gas and Transmission Paths

4. The permit application indicates that Natural Gas-Fired Dew-Point Heater emissions are calculated using the emission factors (kg/MMBtu) for natural gas. Please provide additional information on the manufacturer, capacity and efficiency of the natural gas-fired dew-point heater.

   The Natural Gas Fired Dew Point Heater has not been procured for the project to date and therefore the manufacturer has not been identified. Invenergy will consider manufacturers such as GTS Energy, Gas Tech, and ETI for the supply of the dew point heater. As is consistent with the manufacturers listed above, the heater will have a nominal heat input of 9 MMbtu/hr LHV (9.98 MMbtu/hr HHV) and will have a combustion efficiency of 70 – 75% LHV (63- 67% HHV).

5. The permit application includes a list of two simple cycle combustion turbines that are currently being evaluated and considered for this project. Please provide supplemental data that includes the percent efficiency of each model currently being considered (this information may be represented graphically in load/efficiency curves). Please discuss what the typical operational load for the combustion turbines (ie. 25% or 75% load).

   The typical operation of the combustion turbines is between 48% and 100% of base load. Market conditions will dictate how much generation is needed between those points. Please see Figure 2 below for the overall plant efficiency at ISO conditions from 50% to 100% of base load for both the GE 7FA.03 and 7FA.05 combustion turbine variants.

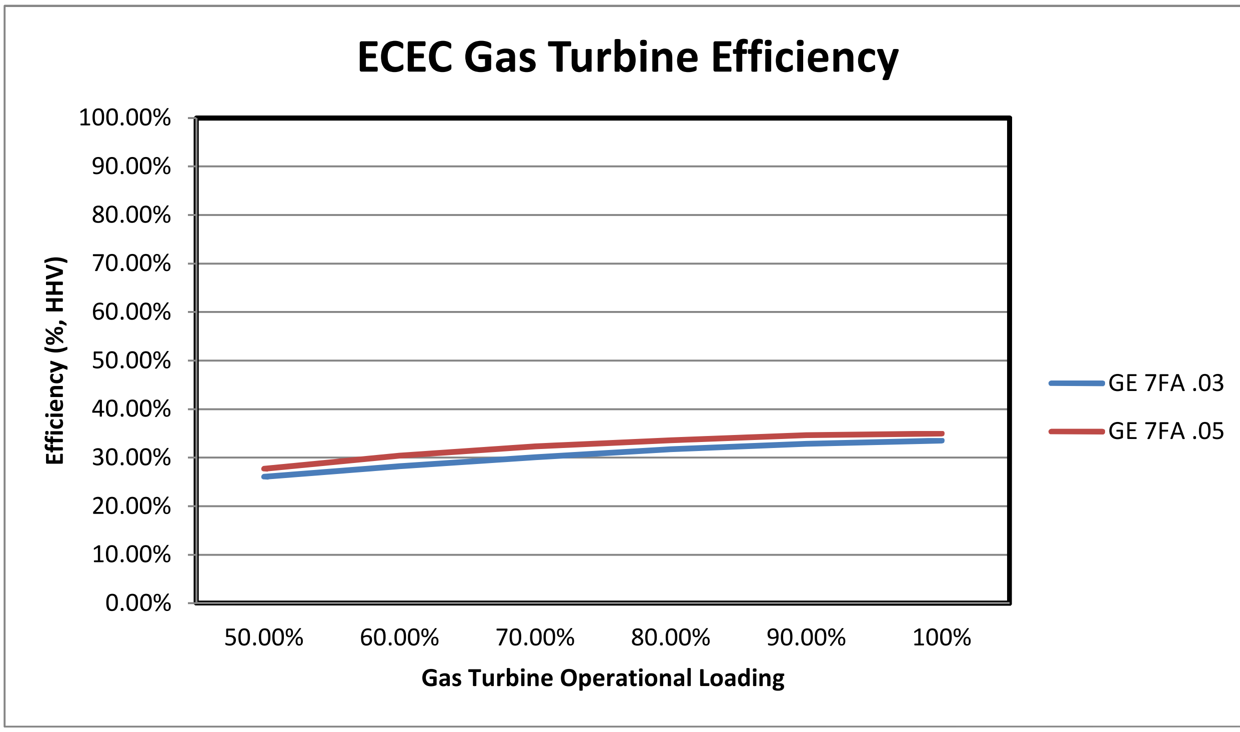

FIGURE 2– ECEC Gas Turbine Efficiency

6. Have you considered a combined cycle combustion turbine for this project? Please include a discussion why a combined cycle turbine is not considered BACT. The permit application states that the peaker plant must be able to shut down quickly and be able to restart in response to electrical demand. How many startups and shutdowns are anticipated for the proposed ECEC project? Also, include the rationale for the number of proposed startup and shutdowns. Please specify if these are cold or hot standby startups. Please discuss the start-up times for each of the combustion turbines being considered in the permit application.

As explained in the Project Scope of Invenergy's GHG Permit Application dated June 25, 2013, the business purpose of the ECEC is to generate 165-386 megawatts (MW), of gross electrical power (in peaking service) in an efficient manner while increasing the reliability of the electrical supply for the State of Texas. As described in section 5.1.1.1, the most efficient way to generate electricity from a natural gas fuel source is the use of a combined-cycle design. However, the use of a combined-cycle design is not practical in this case, since ECEC is intended to provide peaking service, not base-load service.

Combined-cycle combustion turbines (CCCTs) are designed to serve base-load by delivering a set amount of electricity continuously, without interruption, throughout the year. CCCTs are very efficient when operated at full load by utilizing waste heat recovery; however, CCCTs can take up to eight hours to start-up and achieve full load operation. Due to the time required to start up a CCCT and the market's need for generation to quickly respond upon dispatch, a CCCT would therefore not be capable of responding to the peak demand, due to its inability to cycle in shorter intervals. The proposed SCCTs have the ability to be at full load in 60 minutes, and under optimum conditions can respond in as quickly as 30 minutes. Given this response time, the proposed SCCTs can respond with greater flexibility to the peak demand that is currently in the area and will dramatically reduce the excess unused energy, fuel combustion, and associated emissions, when compared with a CCCT.

Invenergy used proprietary production cost models for simple cycle and combined cycle combustion turbines to determine ideal locations, within ERCOT, for a gas fired project. The analysis was based on historical and forward fuel and power prices, generating unit characteristics, heat rates, and general system data. The side-by-side comparison of total production cost, surplus energy cost, gas demand charges and net project costs, all determined that the proposed SCCTs would be the most suitable for this location, based largely on the ability of the unit to quickly cycle and respond to the peaking demand in the area.

An intermediate result of not meeting peaking demand with efficient resources is high clearing prices. High, short-term price volatility is a signal that peaking demand may support additional peaking supplies. Power price volatility near ECEC has been extremely high, relative to other areas of ERCOT, in recent years. Therefore, Invenergy feels these market indicators are signaling a need for a peaking plant in the area.

In addition to summer demand originating from high temperatures, peaking service is needed in the ECEC area because of inconsistent weather patterns. Wind generated resources near ECEC increasingly produce large variability of available energy on the electric delivery system. This intermittent delivery of “must take” electricity requires additional quick-start generating sources such as peaking plants to assist in providing a continuous and reliable supply of power. Wind generated power is also often available near ECEC during off peak periods. This availability depresses clearing prices within the electrical market and reduces the efficiency and economic viability of base-load resources like combined-cycle turbines that would be operating during these off peak times due to their inability to quickly cycle. Solar energy, much like wind, is variable and also requires quick ramping/cycling generation to maintain power supply reliability. Additional solar and wind energy development is planned near ECEC, which is expected to increase the need for peaking service.

Invenergy does not anticipate that there will be enough sustained intermediate or base load growth in the area to support additional combined cycle generation. The Texas Clean Energy Project, a permitted combined cycle facility that is currently slated for construction nearby, would further reduce the need for supply to the intermediate or base load markets in the region.

Invenergy has proposed 500 starts and shutdowns per unit in the NSR Construction Permit Application to the Texas Commission on Environmental Quality (TCEQ). This figure was derived from the ability to start and run for an average of 5 hours per start for the proposed 2,500 hours of operation per year per unit, as the market may dictate. The number of projected startups is indicative of the anticipated number of times per year that these peaking turbines will be able to meet the market price points in the ECEC area and will be called upon for dispatch.

The frequency of dispatch of the ECEC would dictate the type of startup (cold, warm or hot) that would occur so there is no current numerical prediction for each type of start expected per year. The dispatch of the proposed units is anticipated to occur more frequently during the summer months; therefore, it is likely that hot and warm starts will also occur more often than cold starts.

7. The permit application, states that for burner maintenance “there are three basic maintenance levels: combustion inspections, hot gas path inspections and major overhauls.” Please provide supplemental details about each maintenance level such as what it involves and how often, monitoring and recordkeeping requirements will be required. How will you monitor the efficiency of the combustion turbines?

Since the units are proposed for a peaking application, the intervals of maintenance will be dependent on the number of factored starts per unit. A factored start is a representative calculation that takes into account actual starts of the unit plus trips at part, base, and peak load, plus any additional cycles such as emergency starting and fast loading, to determine wear on the unit. Factored starts are calculated through reports compiled on a monthly basis.

For the 7FA.03, the **Combustion Inspection** is a relatively short disassembly shutdown inspection of fuel nozzles, liners, transition pieces, crossfire tubes and retainers, spark plug assemblies, flame detectors and combustor flow sleeves. This inspection concentrates on the combustion liners, transition pieces, fuel nozzles and end caps which are recognized as being the first to require replacement and repair in a good maintenance program. Proper inspection, maintenance and repair of these items will contribute to a longer life of the downstream parts, such as turbine nozzles and buckets. Combustion inspections are not performed at the same intervals on the 7FA.05 due to hardware available in the unit that lasts well beyond the traditional maintenance intervals required for 7FA.03. A combustion inspection is recommended after 450 factored starts on the 7FA.03 variant. The combustion inspection is performed at the same time as the hot gas path inspection on the 7FA.05 variant.

The purpose of the **Hot Gas Path Inspection** (HGPI) is to examine those parts exposed to high temperatures from the hot gases discharged from the combustion process. The HGPI includes the full scope of the combustion inspection and, in addition, a detailed inspection of the turbine nozzles, stator shrouds and turbine buckets. To perform this inspection, the top half of the turbine shell must be removed. A HGPI is performed on both the 7FA.03 and 7FA.05

A HGPI is recommended after 900 factored starts.

The purpose of the **Major Inspection** is to examine all of the internal rotating and stationary components from the inlet of the machine through the exhaust. A major inspection will be scheduled in accordance with the recommendations in the owner’s Operations and Maintenance Manual or as modified by the results of previous borescope and hot gas path inspection.

The work scope involves inspection of all of the major flange-to-flange components of the gas turbine, which are subject to deterioration during normal turbine operation. This inspection includes previous elements of the combustion and hot gas path inspections, in addition to laying open the complete flange-to-flange gas turbine to the horizontal joints.
Removal of all of the upper casings allows access to the compressor rotor and stationary compressor blading, as well as to the bearing assemblies. Prior to removing casings, shells and frames, the unit must be properly supported.

A Major Inspection is recommended after 2,700 factored starts.

Figure 3 illustrates the different scopes of the three maintenance efforts.

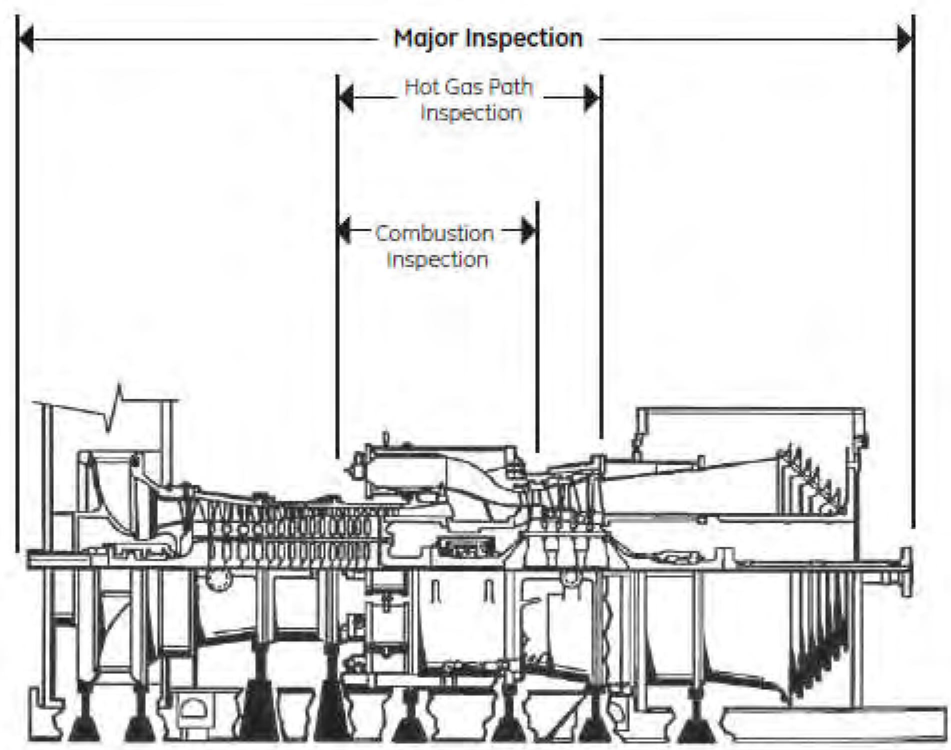

FIGURE 3 – Major Inspection Work Scope[1]

The maintenance inspections for 7FA.03 are based on the following schedule:

450 factored starts, 1st Combustion Inspection
900 factored starts, 1st Hot Gas Path Inspection
1,350 factored starts, 2nd Combustion Inspection
1,800 factored starts, 2nd Hot Gas Path Inspection
2,250 factored starts, 3rd Combustion Inspection

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[1] From page 31, Figure 42 of GE Energy document GER-3620L.1, *Heavy-Duty Gas Turbine Operating and Maintenance Considerations*

2,700 factored starts, 1st Major Inspection

The maintenance inspections for 7FA.05 are based on the following schedule:

900 factored starts, 1st Hot Gas Path Inspection
1,800 factored starts, 2nd Hot Gas Path Inspection
2,700 factored starts, 1st Major Inspection

After a Major Inspection, the cycle begins again starting with the Combustion Inspection for the 7FA.03 or the Hot Gas Path for the 7FA.05. Additional maintenance may be required if high vibrations or exhaust temperatures are detected.

Inspections are performed by Invenergy or a third party company performing the field service work. For recordkeeping, Invenergy, or the selected third party company, is required to submit a report detailing the alignment of the equipment, condition of changed, retained, and replaced parts, and abnormal conditions addressed during the inspection and field service. Invenergy typically executes an agreement with the OEM (GE, for example) to provide maintenance services for the combustion turbines, but may, in the case of this project, take on all required maintenance services of the plant. As part of these services, Invenergy or the OEM monitors the turbines using Monitoring & Diagnostics capability.

Invenergy will be utilizing the Acid Rain Continuous Emissions Monitoring Systems (CEMS) that will be installed on the combustion turbines in order to monitor and demonstrate compliance with the combustion turbine GHG permit conditions. In addition, Invenergy plans to install/maintain a PI data logging system that will allow real-time and historical analysis of performance including heat rate, output, and other factors. The PI system is integrated with the distributed control system (DCS) that will allow plant operators to monitor and control all aspects of plant performance.

Invenergy currently operates eight GE 7FA.03s and is well versed in the maintenance and operations requirements of the machines. Invenergy typically performs annual water washing of the compressor on our combustion turbines, while the unit is off line, to keep the compressor clean and operating efficiently.

8. Please discuss the concentration of CO_2 in the flue gas stream at various proposed operating levels. Please discuss all operating ranges for the combustion turbines being considered in the permit application.

Carbon Dioxide Exhaust Concentrations

GE 7FA.03 Turbine

All CO2 concentrations are in volume % on a dry basis. Values based on GE supplied load profiles.

Ambient Conditions	Turbine Load					
	50%	60%	70%	80%	90%	Base
22°F, 73.4% relative humidity	3.97	4.04	4.11	4.13	4.12	4.04
59°F, 60% relative humidity	3.93	3.99	4.04	4.09	4.08	4.07
97°F, 19.1% relative humidity	-	3.94	3.99	4.00	4.00	4.10

GE 7FA.05 Turbine

All CO2 concentrations are in volume % on a dry basis. Values based on GE supplied load profiles.

Ambient Conditions	Turbine Load					
	50%	60%	70%	80%	90%	Base
22°F, 73.4% relative humidity	4.07	4.07	4.08	4.08	4.14	4.12
59°F, 60% relative humidity	4.19	4.20	4.18	4.10	4.10	4.12
97°F, 19.1% relative humidity	4.03	4.17	4.11	4.04	3.97	4.11

9. Please discuss why a portable gas analyzer for methane is not considered BACT for fugitive emissions. Please provide supplemental information for implementing inspections for fugitive emissions such as how often inspections will be conducted and how the monitoring records will be maintained by the facility.

Leaking natural gas piping components are responsible for releasing fugitive emissions to the atmosphere. Fugitive emissions are calculated according to the natural gas leak factors within the TCEQ guidance document entitled “Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000”.

As most of the piping components at the Ector County Energy Center are in natural gas service, the primary fugitive pollutant will be methane. Fugitive methane leaks account for a very small fraction of the site’s total GHG emissions, making it impractical to capture and/or control fugitive leaks. Nevertheless, Invenergy will implement an AVO (audio visual olfactory) fugitive leak detection and repair (LDAR) program while the site is operational.

The table below outlines several TCEQ approved LDAR programs for the minimization of fugitive leak emissions. Of all the programs, the AVO method has a control efficiency equal to or higher than all other methods. This method should be particularly effective at the Ector County Energy Center, as the fuel lines are in odorized natural gas service. When staff is present, Invenergy will conduct daily AVO walkthroughs of the facility. Records of any identified leaks and the measures used to repair or replace leaking components will be kept on site and will be available for inspection by both the TCEQ and EPA.

The use of a portable gas analyzer to detect odorized natural gas emissions offers no immediate benefit over AVO monitoring. The level of distinct awareness (LOA) for mercaptans by the human nose is less than 1ppm[2]. Even at low concentrations, an AVO walkthrough will readily identify any natural gas leaks without the use of a portable gas analyzer.

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Equipment/Service	**28M**	**28RCT**	**28VHP**	**28MID**	**28LAER**	**Audio/Visual/Olfactory[1]**
Valves						
Gas/Vapor	75%	97%	97%	97%	97%	97%
Light Liquid	75%	97%	97%	97%	97%	97%
Heavy Liquid[2]	0%[3]	0%[4]	0%[4]	0%[4]	0%[4]	97%
Pumps						
Light Liquid	75%	75%	85%	93%	93%	93%
Heavy Liquid[2]	0%[3]	0%[3]	0%[5]	0%[6]	0%[6]	93%
Flanges/Connectors						
Gas/Vapor[7]	30%	30%	30%	30%	97%	97%
Light Liquid[7]	30%	30%	30%	30%	97%	97%
Heavy Liquid	30%	30%	30%	30%	30%	97%
Compressors	75%	75%	85%	95%	95%	95%
Relief Valves (Gas/Vapor)	75%	97%	97%	97%	97%	97%
Open-ended Lines[8]	75%	97%	97%	97%	97%	97%
Sampling Connections	75%	97%	97%	97%	97%	97%

1. Audio, visual, and olfactory walk-through inspections are applicable for inorganic/odorous and low vapor pressure compounds such as chlorine, ammonia, hydrogen sulfide, hydrogen fluoride, and hydrogen cyanide.
2. Monitoring components in heavy liquid service is not required by any of the 28 Series LDAR programs. If monitored with an instrument, the applicant must demonstrate that the VOC being monitored has sufficient vapor pressure to allow reduction.
3. No credit may be taken if the concentration at saturation is below the leak definition of the monitoring program (i.e. (0.044 psia/14.7 psia) x 106 = 2,993 ppmv versus leak definition = 10,000 ppmv).
4. Valves in heavy liquid service may be given a 97% reduction credit if monitored at 500 ppmv by permit condition provided that the concentration at saturation is greater than 500 ppmv.
5. Pumps in heavy liquid service may be given an 85% reduction credit if monitored at 2,000 ppmv by permit condition provided that the concentration at saturation is greater than 2,000 ppmv.

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[2] EPA's "INTERIM ACUTE EXPOSURE GUIDELINE LEVELS (AEGLs), METHYL MERCAPTAN", October 2008, http://www.epa.gov/oppt/aegl/pubs/methylmercaptan_interim_oct_2008.pdf.

6. Pumps in heavy liquid service may be given a 93% reduction credit if monitored at 500 ppmv by permit condition provided that the concentration at saturation is greater than 500 ppmv.
7. If the applicant decides to monitor connectors using an organic vapor analyzer (OVA) at the same leak definition as valves, then the applicable valve reduction credit may be used instead of the 30% reduction credit. If this option is chosen, the applicant shall continue to perform the weekly physical inspections in addition to the quarterly OVA monitoring.
8. The 28 Series quarterly LDAR programs require open-ended lines to be equipped with an appropriately sized cap, blind flange, plug, or a second valve. If so equipped, open-ended lines may be given a 100% control credit.

10. Emission point numbers (EPNs) for the fugitive emission, SF_6 circuit breaker, the diesel-fuel fire water pump engine and the natural gas-fired dew-point heater are provided in the application. Please supplement the process flow diagram with the representation of the GHG sources and associated EPNs. Please discuss in detail the EPN's identified as LOV-1 and LOV-2 in the area map.

The fugitive emissions, the SF6 circuit breakers, and the diesel-fuel fired water pump engine are all now shown on the revised process flow diagram (see attached). The EPN's identified as LOV-1 and LOV-2 are EPN's that were associated with the non-GHG permit application which was submitted to the TCEQ. LOV-1 and LOV-2 do not emit greenhouse gases and so therefore have been removed from the GHG process flow diagram.

Please see updated process flow diagram below:

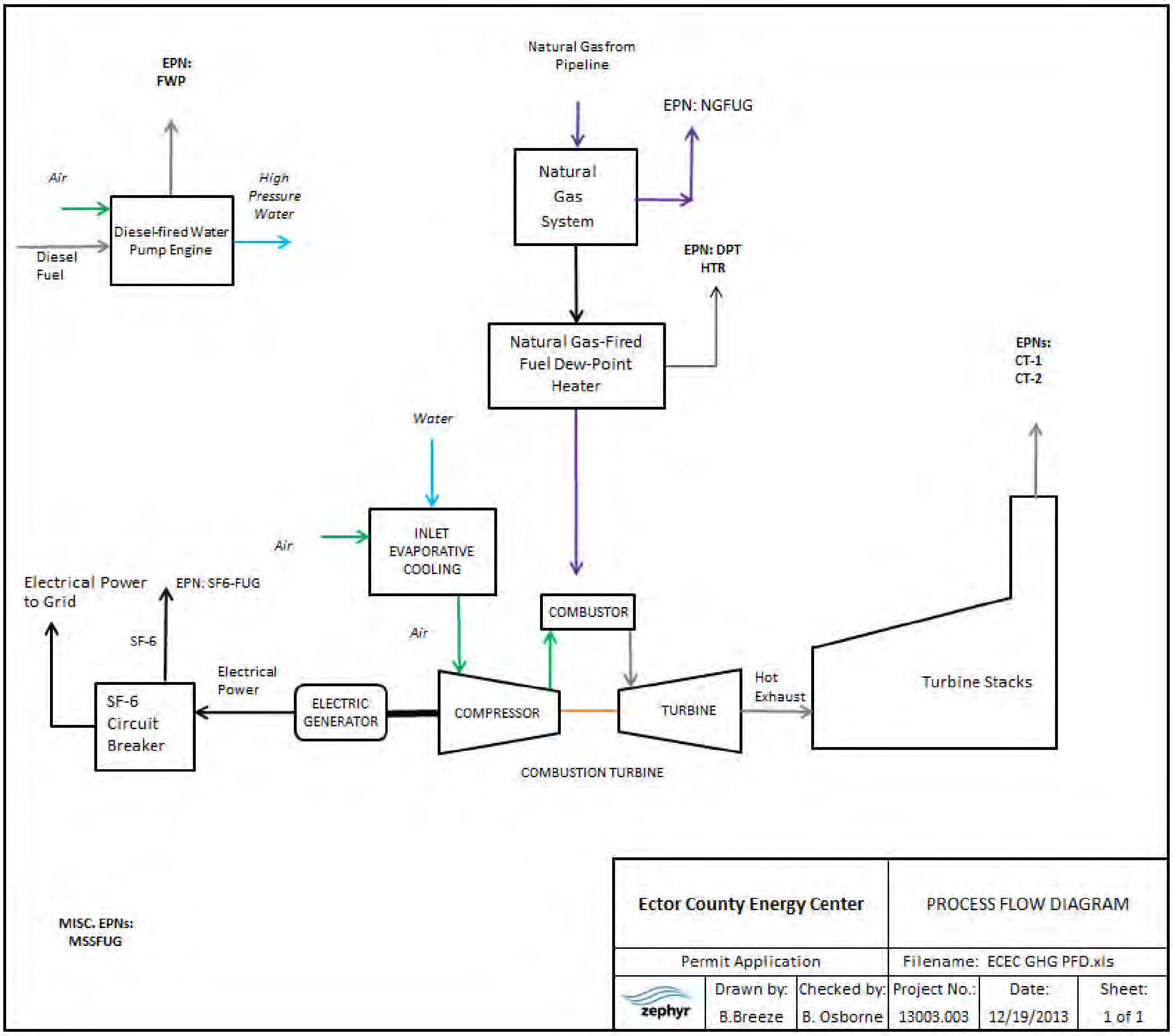

FIGURE 4– Process Flow Diagram

11. Please indicate what the total capacity of the circuit breakers associated with the proposed plant will be for the SF_6 electrical insulation system with leak detection. This discussion should discuss how many circuit breakers are being proposed and discuss the quantity of SF_6 insulating gas per unit.

    Three 138kV SF_6 breakers will be required for the proposed plant. Invenergy has not yet determined the manufacturer of the SF_6 breakers. However, in understanding all of the available options, 80lbs of SF_6 per breaker will accommodate all breakers Invenergy currently has under consideration. Therefore our total SF_6 content on the site will be 240lbs.

12. The global warming potentials (GWP) have been revised. The final rule published on November 29, 2013 in the Federal Register will be effective for all permits issued on or after January 1, 2014. The methane value was increased from 21 to 25 (times more potent than CO2) and the SF6 value was decreased from 23,900 to 22,800. Due to the prospective changes in the emissions

for methane in the Invenergy application, please provide an updated emission tables using the new GWPs so that EPA can cross-check its own calculations.

Updated GWP Calculations provided in Appendix B.

Appendix A:

NSR Construction Permit Application, Submitted to TCEQ Air Permit Initial Review Team 5-13-13

Appendix B:

Updated Emissions Summary