Statement of Basis

Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit
for the Energy Transfer Company, Jackson County Gas Plant

Permit Number: PSD-TX-1264-GHG

March 2012

This document serves as the statement of basis for the above-referenced draft permit, as required by 40 CFR 124.7. This document sets forth the legal and factual basis for the draft permit conditions and provides references to the statutory or regulatory provisions, including provisions under 40 CFR 52.21, that would apply if the permit is finalized. This document is intended for use by all parties interested in the permit.

I. Executive Summary

On August 25, 2011, the Energy Transfer Company (ETC)-Jackson County Gas Plant, submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions. In connection with the same proposed project, ETC submitted a PSD permit application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on September 9, 2011. The project at the Jackson County Gas Plant proposes to construct four natural gas processing plants and associated compression equipment to process residue gas from an existing liquids handling facility. After reviewing the application, EPA Region 6 has prepared the following Statement of Basis (SOB) and draft air permit to authorize construction of air emission sources at the ETC, Jackson County Gas Plant.

This SOB documents the information and analysis EPA used to support the decisions EPA made in drafting the air permit. It includes a description of the proposed facility, the applicable air permit requirements, and an analysis showing how the applicant complied with the requirements.

EPA Region 6 concludes that ETC’s application is complete and provides the necessary information to demonstrate that the proposed project meets the applicable air permit regulations. EPA's conclusions rely upon information provided in the permit application, supplemental information EPA requested and provided by ETC, and EPA's own technical analysis. EPA is making all this information available as part of the public record.

II. Applicant

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III. Permitting Authority

On May 3, 2011, EPA published a federal implementation plan that makes EPA Region 6 the PSD permitting authority for the pollutant GHGs. 75 FR 25178 (promulgating 40 CFR § 52.2305). Texas still retains approval of its plan and PSD program for pollutants that were subject to regulation before January 2, 2011, i.e., regulated NSR pollutants other than GHGs.

The GHG PSD Permitting Authority for the State of Texas is:

EPA, Region 6
1445 Ross Avenue
Dallas, TX 75202

The EPA, Region 6 Permit Writer is:
Aimee Wilson
Air Permitting Section (6PD-R)
(214) 665-7596

The Non-GHG PSD Permitting Authority for the State of Texas is:

Air Permits Division (MC-163)
TCEQ
P.O. Box 13087
Austin, TX 78711-3087

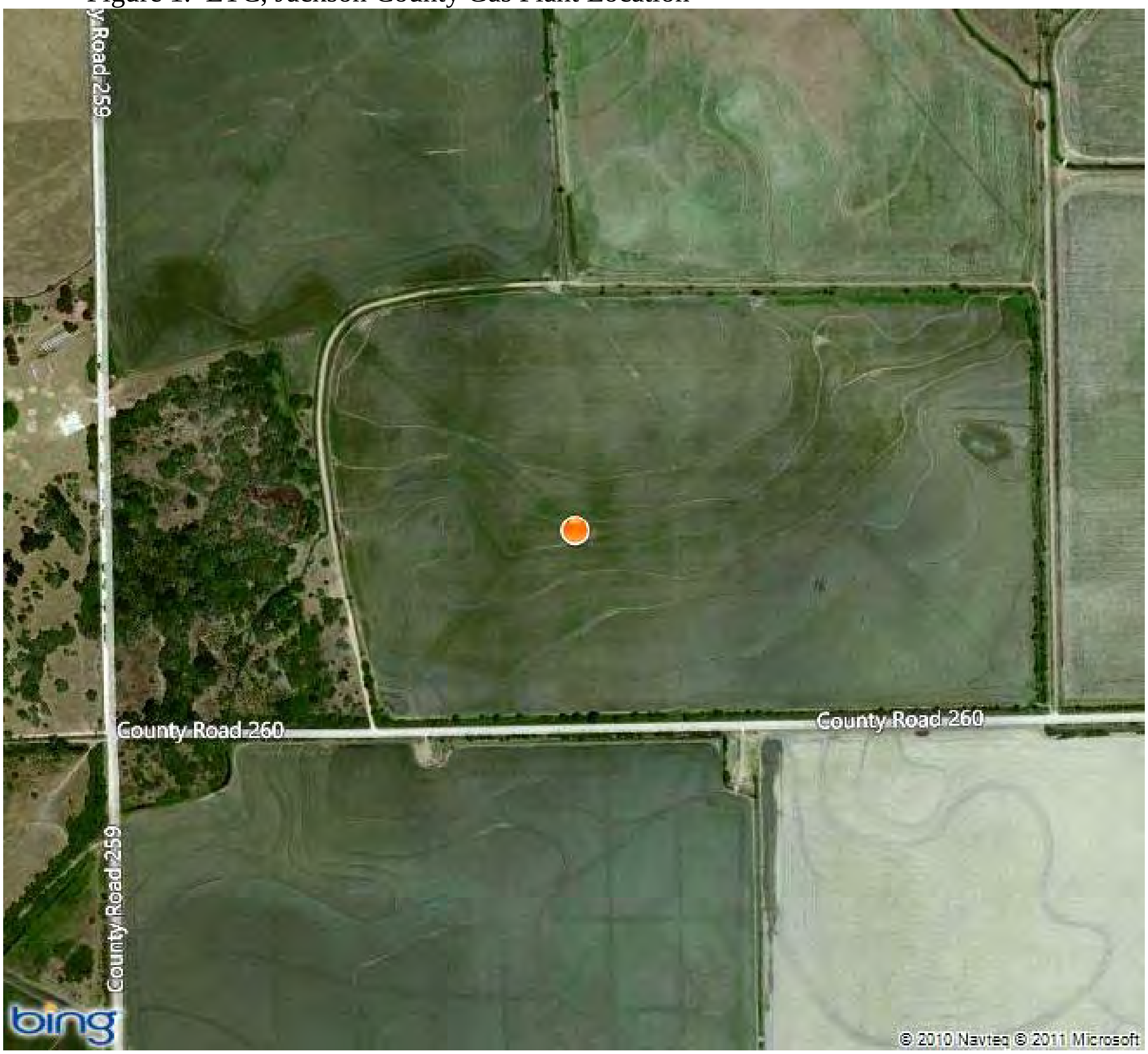
IV. Facility Location

The ETC, Jackson County Gas Plant is located in Jackson County, Texas, and this area is currently designated “attainment” for all NAAQS. The nearest Class 1 area is the Big Bend National Park, which is located well over 100 miles from the site. The geographic coordinates for this facility are as follows:

Latitude: 29º 6’ 34” North
Longitude: - 96º 32’16” West

Below, Figure 1 illustrates the facility location for this draft permit.

Figure 1. ETC, Jackson County Gas Plant Location



V. Applicability of Prevention of Significant Deterioration (PSD) Regulations

EPA concludes ETC's application is subject to PSD review for the pollutant GHGs, because the project would lead to an emissions increase of GHGs for a facility as described at 40 CFR § 52.21(b)(49)(iv). Under the project, increased GHG emissions will have a mass basis over zero tpy and CO_2e emissions are calculated to exceed the applicability threshold of 75,000 tpy (ETC calculates CO_2e emissions of 602,888 tpy). EPA Region 6 implements a GHG PSD FIP for Texas under the provisions of 40 CFR § 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305

As the permitting authority for regulated NSR pollutants other than GHGs, TCEQ has determined the modification is subject to PSD review for non-GHG pollutants. At this time, TCEQ has not proposed the PSD permit amendment for the non-GHG pollutants. The State will issue the non-GHG portion of the permit and EPA will issue the GHG portion.[1]

EPA Region 6 applies the policies and practices reflected in the EPA document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011). Consistent with that guidance, we have not required the applicant to model or conduct ambient monitoring for GHGs, and we have not required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions. Instead, EPA has determined that compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs. We note again, however, that the project has triggered review for regulated NSR pollutants that are non-GHG pollutants under the PSD permit sought from TCEQ.

VI. Project Description

The proposed GHG PSD permit, if finalized, will allow ETC to construct four new natural gas processing plants and associated compression equipment at the existing Jackson County Gas Plant. After the project is operational, the residue gas from an existing onsite liquids handling facility will be sent to the four plants for processing. The vapor pressure of the separated condensate is reduced by the stabilization process (application of heat provided by the Stabilization Unit Heater), where the lighter components are removed and combined with the residue gas for shipping off-site via pipeline (i.e., and transfer to the four plants after the Project). After the project is operational, light-end liquid components driven off in the stabilization process (natural gas liquids, or NGL) will be routed to the NGL amine contactors at the four plants for removal of CO_2 and H_2S in order to provide a cleaner product. The processed gas will then be sent to pipeline for distribution.

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[1] *See* EPA, Question and Answer Document: Issuing Permits for Sources with Dual PSD Permitting Authorities, April 19, 2011, http://www.epa.gov/nsr/ghgdocs/ghgissuedualpermitting.pdf

VII. Applicable Emission Units and BACT Discussion

The majority of the contribution of GHGs associated with the project is from combustion sources (i.e., engines, reboilers, heaters, flare, and thermal oxidizers) and the amine units. The TEG dehydration units and piping component leaks (i.e., fugitive emissions) contribute a minor amount of GHGs. Stationary combustion sources primarily emit CO_2, and small amounts of N_2O and CH_4. The BACT analyses and other technical information in ETC's application are incorporated into this Statement of Basis.

Carbon Capture and Sequestration (CCS)

Within the permit application BACT analysis, ETC provides a 5-step top-down BACT analysis and discusses the technical infeasibility and the economic costs and adverse environmental impact of utilizing carbon capture and sequestration (CCS) technology and an additional cost analysis is provided to support this determination. EPA has reviewed ETC's CCS analysis and has determined that CCS is not economically feasible at this time for this application, and has eliminated CCS as a potential BACT option based on the economic impacts and negative environmental and energy impact. ETC's CCS analysis showed that CCS ranked at the bottom of the list in Step 3 of the 5-step BACT analysis when ranking the remaining control technologies. CCS was then eliminated as BACT in Step 4 as not a feasible or cost effective option based on the lack of readily available technologies, negative environmental impacts, as well as economic reasons.

The analysis provided by the applicant demonstrates that CCS can be eliminated based on its economic, environmental, and energy costs. In its analysis, ETC noted that it is in relatively close proximity to a CO_2 pipeline. The nearest existing pipeline identified by ETC that may transport CO_2 is approximately 60 miles from the plant. This pipeline is owned and operated by a direct competitor to ETC, and therefore the applicant has determined that this is not a viable option for transport of CO_2. However, another company has announced recently the intent to install a pipeline system to receive CO_2 in the next few years.[2] This future pipeline will pass approximately 120 miles from the plant. For the purposes of this BACT analysis, ETC has assumed that the company with the future pipeline is the nearest available CO_2 pipeline. Since the cost of transport and storage of the stack GHG emissions would be higher than the cost of just transport, ETC is conservatively assuming that the announced pipeline would be a viable recipient of the CO_2 emissions and, therefore, addressing the transportation costs only. ETC utilized the March 2010 National Energy Technology Laboratory (NETL) document *Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs DOE/NETL-2010/1447*[3] to estimate the cost associated with the pipeline and associated equipment. Assuming that the CO_2 pipeline company would be able to receive the CO_2 stream, the estimated cost associated with transport of the amine unit vent CO_2 to the pipeline is well over $300,000,000, or $80.80/ton of CO_2 removed. This cost estimate does not include certain costs that would be required, such as liability costs or the costs necessary to install and operate the additional equipment needed to prepare the CO_2 stream for the pipeline. The total pipeline

[2] See permit application pages 35-36 for further discussion.

[3] See *Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs* available at http://www.netl.doe.gov/energy-analyses/pubs/QGESStransport.pdf

annualized cost for CCS over the 10 year expected life of the equipment is $48,000,000 per year.[4] The cost to build the four gas processing plants, covered by this permitting action, is nearly $400,000,000 alone without the additional cost of CCS. As explained more fully below, the addition of the CCS would almost double the capital cost of the facility. Accordingly, we find that CCS is eliminated from consideration because the costs associated with it are economically unreasonable.

If CCS was required for this project, the process required to separate and compress CO_2 is already implemented at the site. In fact, the majority of the site's CO_2 emissions are from the amine units that remove CO_2 from the inlet gas, which is 1.96 mol% CO_2, flowing at 200 MMscfd or 73,000 MMscf/yr per plant, for a sitewide total of 292,000 MMscf/yr. To process this CO_2 stream for CCS, it would need to be further separated, concentrated, and pressurized before it could be accepted by a pipeline. This would require additional equipment to assist in this process. Specifically, the site would need to have additional amine units, cryogenic units, dehydration units, and associated equipment greater than the size of the proposed plants 1 and 2 combined. The estimated cost of the additional equipment is over $275,000,000. In addition to these cost issues, the site of the existing facility does not have the space to allow for the additional equipment that would be needed. Additional cryogenic units or other cooling mechanisms would be required to reduce the CO_2 stream temperature prior to separation, compression, and transmission. The separated CO_2 stream would require large compression equipment to pressurize the CO_2 to transfer to the pipeline. For inlet compression, ETC estimates that an additional eight Caterpillar 3616 engines would be needed. For refrigeration compression, ETC estimates that an additional six Caterpillar 3616 engines would be needed. And for CO_2 compression, ETC estimates that one additional Caterpillar 3606 engine would be needed. Moreover, as explained below, the electricity required to run additional electric or dual drive compressors is not available at the site, so the additional compressors would be natural gas fired. These additional engines would emit additional GHG emissions of approximately 185,000 tons per year. Considering the additional equipment and associated emission sources, implementing CCS at the site would generate additional GHG emissions greater than PSD GHG applicability thresholds and additional $PM_{10}/PM_{2.5}$ and VOC emissions greater than PSD significance thresholds. Therefore, EPA is determining that CCS should also be eliminated as BACT for ETC due to its negative environmental and energy impacts.

As explained above, EPA Region 6 reviewed ETC's CCS cost estimate and believes CCS is financially prohibitive due to its overall cost as a GHG control strategy. The use of CCS on the stack GHG emissions is not economically feasible for the site. Considering the additional equipment and associated emission sources, implementing CCS at the site would generate additional GHGs greater than the major source threshold and additional $PM_{10}/PM_{2.5}$ and VOC emissions greater than PSD significance thresholds. Therefore, EPA has determined at this time that for ETC CCS should be eliminated as BACT for this facility due to the economic impacts and negative environmental and energy impacts.

[4] See the CCS cost analysis on page 37 of the permit application.

Natural Gas-Fired Compressor Engines

As part of the PSD review, ETC provides in the GHG permit application a 5-step top-down BACT analysis for the eight inlet compressor engines and twelve residue compressor engine emission units. In this analysis, ETC identifies the use of dual-drive engines, electric driven engines, and the use of CCS as available control technologies for GHG emissions from these natural gas fired compressor engines. CCS was excluded as explained above. EPA has reviewed the remainder of ETC's BACT analysis for the natural gas-fired compressor engines and finds it sufficient for this proposed permit, as summarized below. A search of the RACT/BACT/LAER Clearing house was completed and no entries were found for natural gas-fired compressor engines that address BACT for GHG emissions.

The refrigeration compressor engines at the site will be powered by electricity, so they will not emit GHGs. The utilization of electric power over the firing of natural gas is considered BACT since it results in zero GHG emissions. The use of electric driven engines was the primary control technology identified in step 3 of the BACT analysis giving a 100% reduction in GHG emissions over a gas fired engine.

The inlet compressors will be equipped with dual-drive engines giving ETC the option of powering the engines by electricity or natural gas. The inlet compressors will have an operational limit for natural gas-fired operation of a combined total of 28,000 hours per year. This will result in reduction in emissions of up to 60% compared to firing natural gas at all times. This was ranked as the fourth control technology in step 3 of the BACT analysis. The electrical infrastructure of the area surrounding the facility is not adequate to provide enough electricity to power the inlet compressors 100% of the time. The engines will fire natural gas approximately 40% of the time, which represents use during peak electrical seasons and when electrical supply to the site is insufficient or unavailable. The site is designed to operate continuously, but electrical supply to the site can vary, dependent on the loads experienced by the electrical supplier. In order to avoid blackouts or rolling brownouts during periods of high usage, ETC can switch to gas-fired operations, thus providing the electricity supplier with added availability during high demand periods. The inlet compressor will have an average net heat rate of 7,555 Btu/hp-hr limit on a 365-day rolling average when firing natural gas. EPA is determining for this site that limiting natural gas operation to a combined total of 28,000 hours per year, or approximately 40% of the time, with electric operation of engines at all other times to be BACT for CO_2, N_2O, and CH_4.

The residue compressors will be powered only by natural gas. There are no manufacturers that sell this type of engine incorporating dual drive technology at this time and therefore dual drive engines were not able to be considered as BACT for this type of engine. The firing of pipeline quality natural gas results in 28% less CO_2 production than fuel oils. Fuel selection was ranked fifth in step 3 of the BACT analysis for engines. EPA is determining for this site that natural gas fuel selection is BACT for CO_2 for these engines. The residue compressor engines shall have an average net heat rate of 7,505 Btu/hp-hr limit on a 365-day rolling average. All gas-fired engines will be lean-burn with low NO_x technology, utilize selective catalytic reduction (SCR), and they will be operated using good combustion practices. Based on EPA's review of ETC's BACT analysis, and from EPA's research, EPA concludes that low NO_x technology, use of SCR, and good combustion practices are considered BACT for CO_2, N_2O, and CH_4 control for the residue compression engines. These control technologies were included in step 3 of the BACT analysis and adopted by the permittee as BACT.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2 and the actual heat input (HHV). To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1. Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 365-day rolling average.

An initial stack test demonstration will be required for CO_2 emissions from emission units C-1100A, C-1100B, C-2100A, C-2100B, C-3100A, C-3100B, C-4100A, C-4100B, C-1121A, C-1121B, C-1121C, C-2121A, C-2121B, C-2121C, C-3121A, C-3121B, C-3121C, C-4121A, C-4121B, and C-4121C. The results of the stack testing will not be used by the EPA to demonstrate compliance with the 12 month rolling average. An initial stack test demonstration for CH_4 and N_2O emissions is not required because the CH_4 and N_2O emission are approximately 0.01% of the total CO_2e emissions from the compressor engines and are considered a de minimis level in comparison to the CO_2 emissions.

Startup and shutdown emissions are included in the overall GHG emission limits contained in the permit. All engines have associated startup and shutdown emissions addressed in this application. Each inlet or residue engine has an associated starter vent, through which a small amount of natural gas (containing some CO_2 and mostly CH_4) is emitted during the engine startup. These emissions are routed to the flare for combustion, which generates GHG emissions. The use of a flare to control engine starter vent emissions was ranked second in step 3 of the BACT analysis. The flare will combust 98% of the CH_4 and convert it to CO_2 which has a lower GWP and therefore is considered an appropriate control for CH_4. Routing these emissions to the flare is environmentally beneficial because of the high destruction of VOC emissions, including methane. Given expected normal operations, engine startups are limited to 20 minutes, once per hour, and 200 times per year for inlet/residue compression. A startup is defined as a period that begins when there is measurable fuel flow to the emission unit and ends when an exhaust temperature of 500°F is reached or 20 minutes, whichever occurs first. Due to the nature of the operation of the facility, it is necessary for the engines to start and stop intermittently to accommodate the flow of product. The start-ups permitted are not excessive and are appropriate for this type of facility. Based on EPA's review of ETC's BACT analysis, and from EPA's research, EPA concludes that control of engine startups by flare is considered BACT for CH_4 control for these units.

Each compressor is equipped with a blowdown vent through which a small amount of natural gas (containing CO_2 and CH_4) is emitted during shutdown (i.e., decompression, which is required for safety purposes). Note that these emissions are re-routed back to the inlet suction when possible. Otherwise, they are routed to the flare, which generates GHG emissions. Given expected normal operations, engine blowdowns to the flare are limited to 30 minutes once per hour, and 72 times per year per engine for inlet/residue compression and 12 times per year per engine for refrigeration compression. A shutdown is defined as the period that begins when the fuel flow is no longer measurable. A shutdown may not result in a blowdown. Installation of a compressor blowdown recovery system and routing remaining blowdown gas to the flare was ranked third in step 3 of the BACT analysis and the permittee has adopted this as BACT for CH_4 control.

The engines shall have a BACT limit based on the CO_2 from the natural gas GCV analysis divided by the measured daily natural gas output for each plant in Million Standard Cubic Feet (MMSCF). This will give a lb of CO_2/MMSCF limit. Compliance is based on a 365-day rolling average. The BACT limit for each plant is 1,871.7 lbs CO_2/MMSCF. Plant I consists of emission units C-1100A, C-1100B, C-1121A, C-1121B, and C-1121C. Plant II consists of emission units C-2100A, C-2100B, C-2121A, C-2121B, and C-2121C. Plant III consists of emission units C-3100A, C-3100B, C-3121A, C-3121B, and C-3121C. Plant IV consists of emission units C-4100A, C-4100B, C-4121A, C-4121B, and C-4121C. BACT limits were calculated based on each engine firing natural gas for 24 hours a day.

ETC anticipates operating each engine without controls for the purpose of combustion tuning at initial startup (called the "burn-in" period). This "burn-in" period is not to exceed 124 hours. However, this "burn-in" period will not impact the fuel firing rate, upon which GHG emission estimates are based. Therefore, the GHG emissions from burn-in operations are not permitted separately in this GHG PSD air permit, but are included in the overall GHG limits provided in the permit.

The flare will have one GHG limit which will include normal operations (pilot fuel firing) and scheduled maintenance, startup, and shutdown (MSS) emissions (combustion of starter and blowdown vent emissions. During periods of startup and shutdown, the permittee must record the time, date, fuel heat input (HHV) in MMBtu/hr and the duration of each startup and shutdown event. In addition to being subject to the GHG emission limit, all emissions during startup and shutdown are minimized by limiting the duration of operation. To demonstrate compliance with the startup and shutdown emissions, ETC shall record the time, date, fuel heat input and duration of each startup and shutdown event.

Records of all emission limit calculations and startup and shutdown events shall be kept on-site for a period of 5-years.

Heaters

The site currently consists of an existing Stabilization Unit heater (EPN H-741) rated at 5.8 MMBtu/hr, that is already permitted by Permit By Rule 30 TAC § 106.352. The proposed plants will each have one hot oil heater rated at 48.45 MMBtu/hr, a trim heater rated at 17.4 MMBtu/hr, each plant will have a molecular sieve regenerator heater rated at 9.7 MMBtu/hr, and each TEG dehydration unit will be equipped with a natural gas-fired heater rated at 3 MMBtu/hr.

The heaters at the site will be fired on pipeline-quality natural gas. The gross calorific value (GCV) of the natural gas is determined semiannually in compliance with 40 CFR Part 98.34(a)(6). According to the GHG Mandatory Reporting Rule, natural gas generally has a homogeneous nature and a low variability in the characteristics of the fuel. The GCV analysis will be used to determine compliance with the BACT limit.

The heaters are all rated at <50 MMBtu/hr. All heaters, except for EPN H-741, will be equipped with next generation ultra-low-NO_x burners (NGULNB) and burner management systems. Step 3 of the BACT analysis identified that a burner management system with intelligent flame ignition, flame intensity, and flue gas recirculation as the highest BACT for heaters. Specifically, the heaters will be equipped with Low-NO_x staged/quenching (flue gas recirculating) burners capable of meeting 0.036 lb-NO_x/MMBtu with additional excess O_2 (i.e., requiring a larger combustion air blower). The heaters will be equipped with a burner management system with intelligent flame ignition, flame intensity controls, and flue gas recirculation. As explained below, EPA is determining for this facility that a good combustion practice along with a burner management system is BACT for heaters and reboilers for CO_2, N_2O, and CH_4.

The heaters are tuned annually for thermal efficiency. Annual tune-ups and maintenance can result in up to a 10% reduction in CO_2 emissions, as identified in the BACT analysis. The heaters' air and fuel valves will be mechanically linked to maintain the proper air to fuel ratio. Thus, controlling the air/fuel ratio reduces CO_2 emissions and is considered as part of BACT. EPA has determined that for this source, annual tune-ups, routine maintenance, and controlling the air to fuel ratio are BACT for the heaters.

The heaters shall have a BACT limit based on the CO_2 from the natural gas GCV analysis divided by the measured daily natural gas output for each plant in Million Standard Cubic Feet (MMSCF). This will give a lb of CO_2/MMSCF limit. Compliance is based on a 365-day rolling average. The BACT limit for each plant is 1,102.5 lbs CO_2/MMSCF. Plant I consists of heaters H-1706, H-7810, H-7820, and H-7410. Plant II consists of heaters H-2706, H-7811, H-7821, and H-7411. Plant III consists of heaters H-3706, H-7812, H-7822, and H-7412. Plant IV consists of heaters H-4706, H-7813, H-7823, and H-7413.

Startup and shutdown emissions are authorized. All heaters have associated startup and shutdown emissions addressed in this application. Start up operations, for heaters will be limited to 30 minutes. The emission rate during start-up and shutdown are identical to normal operation. This is determined for this facility as BACT.

Amine Units

Each gas processing plant will be equipped with an amine unit. The amine units are designed to remove CO_2 from the natural gas. The generation of CO_2 (GHG) is inherent to the process, and a reduction of CO_2 emissions by process changes would only be achieved by a reduction in the process efficiency, which would result in natural gas that would not meet pipeline quality specifications and leave CO_2 in the natural gas for emission to the atmosphere at downstream sources. The amine units do emit methane (GHG) at the point of amine regeneration, due to a small amount of natural gas becoming entrained in the rich amine. The amine units are each designed to include a flash tank, in which gases (i.e., including CO_2 and methane) are removed from the rich amine stream prior to regeneration, thereby reducing the amount of waste gas created. The amine unit flash tank off gases will all be recycled back into each plant for reprocessing, instead of venting to atmosphere or combustion device. The design and proposed operation of the amine units and the flash tank off gas recovery system are considered BACT for CO_2 and CH_4 for the amine units. This was the highest ranked control technology in step 3 of the

BACT analysis for the amine units giving a 100% reduction in GHG emissions over no control. The amine unit regenerator vent is routed to a thermal oxidizer, this control device will reduce the methane emissions by 99.9% and will convert those emissions to CO_2, which has a lower GWP. EPA is determining for this site that the use of a thermal oxidizer for control of CH_4 is BACT for the amine units. Routing the amine unit regenerator vent to a thermal oxidizer was ranked second in step 3 of the BACT analysis for the amine units giving a 99.9% reduction in emissions of CH_4 while generating CO_2 emissions.

TEG Dehydrator Units

Each gas processing plant will be equipped with a TEG dehydrator unit. The TEG dehydration units are located downstream of the amine units, so that the vast majority of the CO_2 entrained in the natural gas has already been removed. Similar to the amine units, the TEG dehydration units do emit CO_2 and methane at the point of regeneration due to natural gas becoming entrained in the rich glycol. The TEG dehydrator units are each designed to include a flash tank, in which gases (i.e., including CO_2 and methane) are removed from the rich glycol stream prior to regeneration, thereby reducing the amount of waste gas created. The TEG dehydrator flash tank off gases will all be recycled back into each plant for reprocessing, instead of venting to atmosphere or combustion device. The design and proposed operation of the TEG dehydrator unit and the flash tank off gas recovery system are considered BACT for CO_2 and CH_4 for the TEG dehydrator units. This was the highest ranked control technology in step 3 of the BACT analysis for the TEG dehydrator units giving a 100% reduction in GHG emissions over no control. The TEG dehydrator unit regenerator vent is routed to a thermal oxidizer. This control device will reduce the methane emissions by 99.9% and will convert those emissions to CO_2, which has a lower GWP. EPA is determining for this site that the use of a thermal oxidizer for control of CH_4 is BACT for the TEG dehydrator units. Routing the TEG dehydrator unit regenerator vent to a thermal oxidizer was ranked second in step 3 of the BACT analysis for the TEG dehydrator units giving a 99.9% reduction in emissions of CH_4 while generating CO_2 emissions

Thermal Oxidizers

Each gas processing plant will be equipped with a thermal oxidizer. Emissions from each plant's amine unit regenerator vent and each TEG dehydration unit regenerator vent are routed to a thermal oxidizer for control of H_2S and VOCs in the exhaust streams. The emission limits for the thermal oxidizers was adjusted by an increase of 10% over the calculated PTE to account for the process gas variability.[5] The process-related CO_2 emissions from each amine unit and TEG dehydration unit will flow through the thermal oxidizers to the atmosphere, and the hydrocarbon emissions, including methane, will be oxidized to form combustion-related GHGs. The oxidizers have a 99.9% DRE (Destruction and Removal Efficiency) for hydrocarbon compounds, so 0.1% of the methane will pass through the oxidizers uncombusted, as process-related GHGs. In addition, the oxidizers will fire pipeline quality natural gas (i.e., generating combustion-related GHGs), at a maximum rate of 7 MMBtu/hr, as needed to maintain a combustion chamber temperature of at least 1,400 ^{o}F.

[5] The emission calculations are based on a representative sample for current conditions and may change.

An initial performance demonstration will be required of thermal oxidizers at the site for CH_4. Annual compliance testing will be required to show ongoing compliance. The Permittee shall measure CH_4 concentrations in the thermal oxidizer inlet and exhaust streams to demonstrate a minimum destruction efficiency of 99.9 % by weight at a minimum combustion chamber temperature of 1,400 °F. ETC's BACT analysis identified proper thermal oxidizer operation and annual tune-ups as BACT for the thermal oxidizers. EPA is determining for this site that good combustion practices and periodic compliance testing is BACT for CH_4 control for thermal oxidizers.

Flares

The site has two flares. The proposed project will have an intermittent plant flare (FS-800) that will be utilized to control emissions associated with compressor/engine blowdowns and starter vents, generating combustion-related GHGs. The plant flare has 98% destruction and removal efficiency (DRE), so 2% of the methane in the blowdown and starter vents will pass through the flare as process-related GHG emissions. The flare also combusts pipeline quality natural gas, through its pilot, which has a firing rate of 0.1 MMBtu/hr, generating a small amount of combustion-related GHGs. The flare is not a continuous process flare, but an intermittent use MSS flare. Therefore, no continuous stream other than pilot gas is being combusted.

The site also has an existing truck loading flare (TL-Flare). This flare combusts the emissions captured by the vapor recovery unit (VRU) which recovers emissions from truck loading activities at the stabilization unit. Based upon TCEQ guidance, the VRU system has been given a 98.7% capture efficiency based upon the inspection schedule of the tanker trucks (as required by 40 CFR Subpart 60, Part XX-Standards of Performance for Bulk Gasoline Terminals). The flare has 98% destruction efficiency. When the VRU is down for maintenance, truck loading is prohibited.

ETC's BACT analysis identified proper flare operation as BACT for the flares. EPA is determining for this site that good combustion practices and demonstrating initial and ongoing compliance in accordance with 40 CFR Part 60.18 is BACT for CO_2 control for flares.

Fugitive Emission Sources

EPA has reviewed and concurs with ETC's Fugitive Emission Sources BACT analysis. Based on ETC's top-down BACT analysis for fugitive emissions, ETC concludes that using the TCEQ 28 LAER[6] leak detection and repair (LDAR) program is the appropriate BACT control technology option. ETC also identified and adopted the use of dry compressor seals, use of rod packing for reciprocating compressors, and the use of low-bleed gas-driven pneumatic controllers or air-driven pneumatic controllers as BACT for fugitives. EPA determines that the TCEQ 28LAER work practice standard for fugitives for control of CH_4 emissions is BACT.

[6] The boilerplate special conditions for the TCEQ 28LAER LDAR program can be found at http://www.tceq.state.tx.us/assets/public/permitting/air/Guidance/NewSourceReview/bpc_rev28laer.pdf. These conditions are included in the TCEQ issued NSR permit.

VIII. Threatened and Endangered Species

Pursuant to Section 7(a)(2) of the Endangered Species Act (ESA) (16 U.S.C. 1536) and its implementing regulations at 50 CFR Part 402, EPA is required to insure that any action authorized, funded, or carried out by EPA is not likely to jeopardize the continued existence of any federally-listed endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat.

To meet the requirements of Section 7, EPA is relying on a Biological Assessment (BA) prepared by the applicant and reviewed by EPA. Further, EPA designated ETC as its non-federal representative for purposes of preparation of the BA and for conducting informal consultation. On September 28, 2011, project representatives from ETC and combined federal agency staff from the US EPA, the U.S. Fish and Wildlife Service (USFWS) and the National Marine Fisheries Service (NMFS) met to discuss the scope of the project for preparation of ETC's biological assessment.

The BA identified two species — the whooping crane (*Grus americana*) and the West Indian manatee (*Trichechus manatus*) — that are on the USFWS list of endangered species for Jackson County, Texas. The project and defined action area are solely within Jackson County, approximately 45 miles from the Gulf Coast. Although both of these species have the potential to occur in Jackson County, because the proposed project is located approximately 45 miles from the Gulf Coast, the manatee will not be present within the action area.

As for the whooping crane, the closest known occurrence is approximately 35 miles away from the action area and the pasture land, mesic woodlands, and active and fallow agricultural land within the action area are not preferred foraging or loafing habitats for this species and there is no known habitat within the action area. However, it is theoretically possible that whooping cranes could enter the action area on a rare and transient basis. During migration, whooping cranes can be blown or driven off their preferred routes or during unseasonable conditions such as drought, whooping cranes may travel great distances in search of food. In addition, whooping cranes and other birds have documented striking potential with vertical structures and overhead electrical supply wires. To minimize these strikes, ETC has committed to install diverters on proposed new electrical service lines and vertical structures at the plant site.

Based on the information provided in the BA, EPA concludes that the proposed PSD permit allowing ETC to construct the proposed gas plant will have no effect on the West Indian manatee because of the project's distance from the coast. However, because of the rare potential for use of the project site during migration, EPA has determined that this project may affect, but is not likely to adversely affect the whooping crane. Because of EPA's "may effect" determination, EPA and ETC (as EPA's designated non-federal representative) have entered into informal consultation with the USFWS. By letter dated March 7, 2012, EPA initiated informal consultation with the Southwest Region, Corpus Christi, Texas Ecological Services Field Office, of the USFWS by submitting a copy of the BA and requesting USFWS's written concurrence with EPA's "not likely to adversely effect" determination.

IX. National Historic Preservation Act (NHPA)

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties eligible for inclusion in the National Register of Historic Places. To make this determination, EPA relied on a cultural resource report prepared by TAS, Inc., ETC's consultant, submitted on September 15, 2011. Upon receipt of the report, EPA sent letters to Indian tribes identified by the Texas Historical Commission as having historical interests in Texas to inquire if any of the tribes wished to consult with EPA in the Section 106 process. EPA received no tribal requests for participation as a consulting party or comments about the project.

TAS conducted an archival search at the Texas Historical Commission and conducted a field survey. Following 55 shovel tests, TAS found no prehistoric sites. During its field survey, TAS identified a modern, recently used, irrigation pump, a small scatter of bricks and assorted modern trash (drums and plastic bottles) and a collapsed storage shed on the property. The 8 meter by 10 meter collapsed storage shed was constructed of corrugated metal and milled lumber with modern nails. The floor was earthen and it appears to have housed farm equipment.

Based on the information provided in the cultural resources report, the shed, pump, bricks and trash are not properties (structures or sites) that meet the criteria for inclusion in the National Register located in 36 CFR 60.4. This is because they are not significant from architectural or artistic distinction or historical importance or value, nor are they associated with a historic person or event, or a birthplace or grave of a historical figure of outstanding importance. Further, there are no cemeteries or reconstructed buildings at the site. Finally, the property is not of exceptional significance.

EPA Region 6 determines this project will have no effect on properties eligible for the National Register. EPA will provide a copy of this report to the State Historic Preservation Officer for consultation and concurrence with this determination. Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties.

X. Environmental Justice (EJ)

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

EPA maintains an ongoing commitment to ensure environmental justice for all people, regardless of race, color, national origin, or income. Ensuring environmental justice means not only protecting human health and the environment for everyone, but also ensuring that all people are treated fairly and are given the opportunity to participate meaningfully in the development, implementation, and enforcement of environmental laws, regulations, and policies.

ETC's proposed location is approximately 4 miles north of the City of Ganado, in a rural location. EPA has conducted a preliminary demographic analysis based on the project location, which suggested that environmental justice concerns are unlikely to be raised in connection with the permitting decision. This analysis has been added to the supporting file for this permit. Commenters are welcome to bring particular environmental justice concerns or information to our attention during the public comment period. All such comments that are received during the draft permit public comment period will be evaluated prior to the final permit decision.

XI. Conclusion and Proposed Action

Based on the information supplied by ETC, our review of the analyses contained the TCEQ PSD Permit Application and the GHG PSD Permit Application, and our independent evaluation of the information contained in our Administrative Record, it is our determination that the proposed facility would employ BACT for GHGs under the terms contained in the draft permit. Therefore, EPA is proposing to issue ETC a PSD permit for GHGs for the facility, subject to the PSD permit conditions specified therein. This permit is subject to review and comments. A final decision on issuance of the permit will be made by EPA after considering comments received during the public comment period.

Appendix

APPENDIX

Annual Facility Emission Limits

Annual emissions, in tons per year (TPY) on a 12-month, rolling average, shall not exceed the following:

Table 1. Facility Emission Limits

ID No.	Description	GHG Mass Basis			CO_2e
			Lb/Hr	TPY[1, 2]	TPY[1, 2]
C-1100A, C-1100B, C-2100A, C-2100B, C-3100A, C-3100B, C-4100A, and C-4100B	8 Dual-Drive Inlet Compressor Engines[3]	CO_2	1,723.58	21,944.53	21,966
		CH_4	0.03	0.41	
		N_2O	0.003	0.04	
C-1121A	Unit 1 of 3 Natural Gas Fired Caterpillar 3616 engines Plant 1 of 4	CO_2		18,195.38	18,213
		CH_4		0.34	
		N_2O		0.03	
C-1121B	Unit 2 of 3 Natural Gas Fired Caterpillar 3616 engines Plant 1 of 4	CO_2		18,195.38	18,213
		CH_4		0.34	
		N_2O		0.03	
C-1121C	Unit 3 of 3 Natural Gas Fired Caterpillar 3616 engines Plant 1 of 4	CO_2		18,195.38	18,213
		CH_4		0.34	
		N_2O		0.03	
C-2121A	Unit 1 of 3 Natural Gas Fired Caterpillar 3616 engines Plant 2 of 4	CO_2		18,195.38	18,213
		CH_4		0.34	
		N_2O		0.03	
C-2121B	Unit 2 of 3 Natural Gas Fired Caterpillar 3616 engines Plant 2 of 4	CO_2		18,195.38	18,213
		CH_4		0.34	
		N_2O		0.033	
C-2121C	Unit 3 of 3 Natural Gas Fired Caterpillar 3616 engines Plant 2 of 4	CO_2		18,195.38	18,213
		CH_4		0.34	
		N_2O		0.03	
C-3121A	Unit 1 of 3 Natural Gas Fired Caterpillar 3616 engines Plant 3 of 4	CO_2		18,195.38	18,213
		CH_4		0.34	
		N_2O		0.03	
C-3121B	Unit 2 of 3 Natural Gas Fired Caterpillar 3616 engines Plant 3 of 4	CO_2		18,195.38	18,213
		CH_4		0.34	
		N_2O		0.03	

ID No.	Description	GHG Mass Basis			CO_2e
			Lb/Hr	TPY[1, 2]	TPY[1, 2]
C-3121C	Unit 3 of 3 Natural Gas Fired Caterpillar 3616 engines Plant 3 of 4	CO_2		18,195.38	18,213
		CH_4		0.34	
		N_2O		0.03	
C-4121A	Unit 1 of 3 Natural Gas Fired Caterpillar 3616 engines Plant 4 of 4	CO_2		18,195.38	18,213
		CH_4		0.34	
		N_2O		0.03	
C-4121B	Unit 2 of 3 Natural Gas Fired Caterpillar 3616 engines Plant 4 of 4	CO_2		18,195.38	18,213
		CH_4		0.34	
		N_2O		0.03	
C-4121C	Unit 3 of 3 Natural Gas Fired Caterpillar 3616 engines Plant 4 of 4	CO_2		18,195.38	18,213
		CH_4		0.34	
		N_2O		0.03	
H-1706	Plant 1 of 4 Hot Oil Heater	CO_2		24,830.49	24,855
		CH_4		0.47	
		N_2O		0.05	
H-7810	Plant 1 of 4 Trim Heater	CO_2		8,908.26	8,917
		CH_4		0.17	
		N_2O		0.02	
H-2706	Plant 2 of 4 Hot Oil Heater	CO_2		24,830.49	24,855
		CH_4		0.47	
		N_2O		0.05	
H-7811	Plant 2 of 4 Trim Heater	CO_2		8,908.26	8,917
		CH_4		0.17	
		N_2O		0.02	
H-3706	Plant 3 of 4 Hot Oil Heater	CO_2		24,830.49	24,855
		CH_4		0.47	
		N_2O		0.05	
H-7812	Plant 3 of 4 Trim Heater	CO_2		8,908.26	8,917
		CH_4		0.17	
		N_2O		0.02	
H-4706	Plant 4 of 4 Hot Oil Heater	CO_2		24,830.49	24,855
		CH_4		0.47	
		N_2O		0.05	
H-7813	Plant 4 of 4 Trim Heater	CO_2		8,908.26	8,917
		CH_4		0.17	
		N_2O		0.02	

ID No.	Description	GHG Mass Basis			CO_2e
			Lb/Hr	TPY[1, 2]	TPY[1, 2]
H-7820	Plant 1 Molecular Sieve Regeneration Heater	CO_2		4,966.10	4,971
		CH_4		0.09	
		N_2O		0.01	
H-7821	Plant 2 Molecular Sieve Regeneration Heater	CO_2		4,966.10	4,971
		CH_4		0.09	
		N_2O		0.01	
H-7822	Plant 3 Molecular Sieve Regeneration Heater	CO_2		4,966.10	4,971
		CH_4		0.09	
		N_2O		0.01	
H-7823	Plant 4 Molecular Sieve Regeneration Heater	CO_2		4,966.10	4,971
		CH_4		0.09	
		N_2O		0.01	
H-7410	Plant 1 of 4 TEG Dehydrator Unit Regeneration Gas Heater	CO_2		1,535.91	1,537
		CH_4		0.03	
		N_2O		0.003	
H-7411	Plant 2 of 4 TEG Dehydrator Unit Regeneration Gas Heater	CO_2		1,535.91	1,537
		CH_4		0.03	
		N_2O		0.003	
H-7412	Plant 3 of 4 TEG Dehydrator Unit Regeneration Gas Heater	CO_2		1,535.91	1,537
		CH_4		0.03	
		N_2O		0.003	
H-7413	Plant 4 of 4 TEG Dehydrator Unit Regeneration Gas Heater	CO_2		1,535.91	1,537
		CH_4		0.03	
		N_2O		0.003	
TO-1	Plant 1 Thermal Oxidizer[4]	CO_2		48,369.99	48,377
		CH_4		0.15	
		N_2O		0.01	
TO-2	Plant 2 Thermal Oxidizer[4]	CO_2		48,369.99	48,377
		CH_4		0.15	
		N_2O		0.01	
TO-3	Plant 3 Thermal Oxidizer[4]	CO_2		48,369.99	48,377
		CH_4		0.15	
		N_2O		0.01	
TO-4	Plant 4 Thermal Oxidizer[4]	CO_2		48,369.99	48,377
		CH_4		0.15	
		N_2O		0.01	

ID No.	Description	GHG Mass Basis			CO_2e
			Lb/Hr	TPY[1, 2]	TPY[1, 2]
FS-800	Plant Flare, Compressor Engine Blowdown/Starter Vents to Flare	CO_2		3,531.52	3,872
		CH_4		16.10	
		N_2O		0.01	
TL-FLARE	Truck Loading Flare (Controlled Condensate Loading)	CO_2		893.20	893
		CH_4		0.001	
		N_2O		0.001	
H-741	Stabilization Unit Heater	CO_2		2,969.42	2,972
		CH_4		0.06	
		N_2O		0.006	
Totals		CO_2		**602,126.23**	**602,888**
		CH_4		**24.29**	
		N_2O		**0.79**	

1. Compliance with the annual emission limits (tons per year) is calculated on a 12-month rolling basis, and is recalculated each month.
2. The TPY emission limits specified in this table are not to be exceeded for this facility and includes emissions only from the facility during all operations and includes MSS activities.
3. Dual-drive engines have a combined gas-fired operating limit of 28,000 hours combined. The short term lb/hr limit is per each engine during gas fired operation. The TPY limit is for all 8 units combined.
4. The emission limit for the Thermal Oxidizers has been adjusted to allow for a 10% increase of emissions over the calculated PTE to allow for process gas variability. Emission calculations are based on a representative sample for current conditions and may change.