Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for Energy Transfer Partners, L.P. dba Lone Star NGL, LLC, Mont Belvieu Gas Plant

Permit Number: PSD-TX-93813-GHG

August 2012

This document serves as the Statement of Basis (SOB) 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 December 14, 2011, Energy Transfer Partners, L.P. (ETP) dba Lone Star NGL, LLC (Lone Star) Mont Belvieu Gas Plant, submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions from a proposed modification. In connection with the same proposed modification project, Lone Star NGL submitted an oil and gas production facilities standard permit revision application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on December 14, 2011. The project at the Mont Belvieu Gas Plant proposes to make modifications to the existing fractionation (FRAC I) train and construct a second fractionation (FRAC II) train at the existing natural gas processing plant. Both trains (FRAC I and FRAC II) will fractionate Y-grade natural gas liquids (NGL) through a series of trayed columns that separate the NGL into constituent gas products, which include ethane, propane, butanes, and natural gasoline, for sale to customers. After reviewing the application, EPA Region 6 has prepared the following Statement of Basis (SOB) and draft air permit to authorize modification and construction of air emission sources at the Lone Star NGL, Mont Belvieu 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 Lone Star NGL'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 requested by EPA and provided by Lone Star NGL, 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). The State of 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

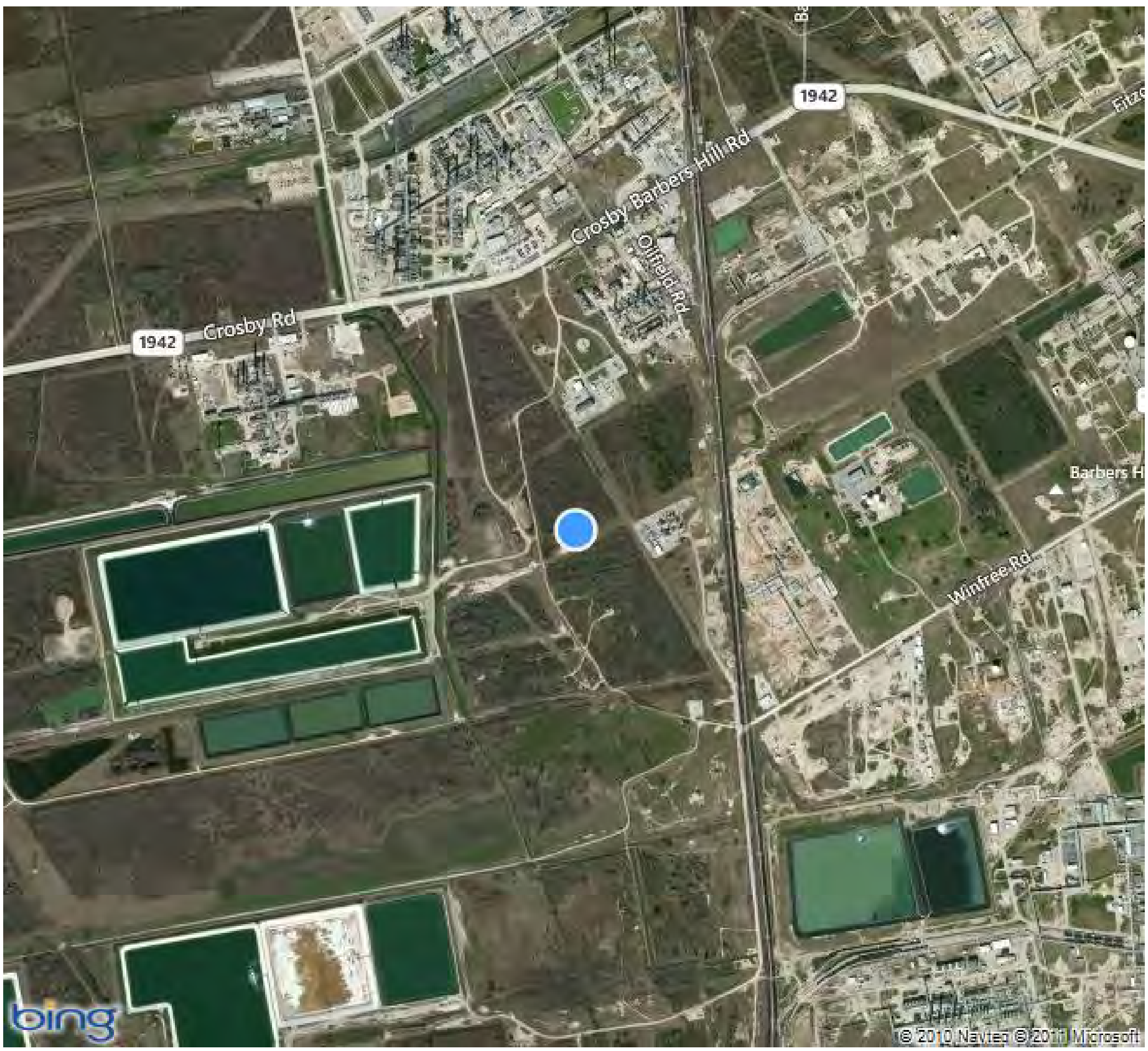
IV. Facility Location

The Lone Star NGL, Mont Belvieu Complex is located in Chambers County, Texas, and this area is currently designated "nonattainment" for Ozone. 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 51' 0" North
Longitude: -94º 54'37" West

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

Figure 1. Lone Star NGL, Mont Belvieu Gas Plant Location



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

EPA concludes Lone Star NGL'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)(v). Under the project, the source is an existing minor source for PSD and the modification alone exceeds the threshold of 100,000 tpy CO_2e (equals or exceeds 100/250 TPY GHG mass basis). Lone Star NGL calculates CO_2e emissions of 408,663 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 not subject to PSD review for non-GHG pollutants. TCEQ issued the revised standard permit on May 29, 2012.[1] Under the limits of the minor NSR permit, there will not be net significant increases of regulated NSR pollutants other than GHGs in conjunction with the project.

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.

VI. Project Description

The proposed GHG PSD permit, if finalized, will allow Lone Star NGL to modify the existing fractionation train (FRAC I) and construct a second fractionation train (FRAC II) at the natural gas processing plant located in Mont Belvieu. Both trains will fractionate Y-grade NGL through a series of trayed columns that separate the NGL into the constituent gas products, which include purity ethane, propane, butanes, and natural gasoline, for sale to customers. Both fractionation trains (FRAC I and FRAC II) will process approximately 100,000 barrels per day each based on a Y-grade purity feed containing 54% ethane. FRAC I and FRAC II can process a wide range of Y-grade purity feed containing between 38% to 54% ethane. The Y-grade purity feed with 38% ethane is a heavier product which requires a higher heat duty. Therefore, the maximum firing rate of the heaters is based on the 38% ethane Y-grade feed.

[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

The FRAC I and FRAC II trains are identical. The first stage in each fractionation train (FRAC I and FRAC II) is an Amine Unit. This unit will use amine contactors to remove CO_2 and H_2S impurities from the NGL stream. Some hydrocarbons will also be absorbed in the process. Specifically, the rich amine will be routed to an amine regenerator, where heat from the fractionation process' hot oil system will enable the volatilization of the CO_2, H_2S, and hydrocarbons (primarily VOC) from the rich amine stream. The resulting lean amine will be returned to the amine contactors for reuse. The Amine Unit will be a closed loop system. Waste gas from the amine regenerator, which is composed of CO_2, H_2S, and VOC, will be routed to the thermal oxidizer (TO) for combustion of H_2S and VOC, and the combustion will generate SO_2 and additional CO_2 emissions. The amine unit flash tank emissions will also be sent to the TO. The TO will be designed to combust low-VOC concentration gas and will have a fuel rating of 10 MMBtu/hr, which will keep the temperature in the combustion chamber at or above 1,400 ^oF. The TO will generate combustion-related GHG emissions. From the Amine Unit, the NGL will be routed through a Molecular Sieve dehydration unit, where the water content of the NGL will be reduced. A regeneration heater will heat a small amount of natural gas that is slip-streamed from the natural gas stream as needed to regenerate the sieve beds. The gas will then be routed back into the system inlet. There are two beds in the molecular sieve design, and one bed will be regenerated at a time. The Molecular Sieve unit will not have vents to the atmosphere. The wet gas from the beds that are regenerated will be routed back to the system. The only GHG emissions from the Molecular Sieve will be fugitive piping equipment leaks. From the Molecular Sieve dehydration unit, the NGL will be fed to a series of trayed column for separation into constituent product gases. No GHG emissions will be generated from the product columns, because the processes will be closed systems and most, if not all, CO_2 is removed at the Amine Unit. Additionally, very little, if any, methane is contained in the NGL that will enter the plant.

FRAC I and FRAC II will employ a hot oil system that will provide heat to the process. By using hot oil, heat can be transferred to the fractionation process with a minimum loss of heat to the oil, allowing for a quicker recovery to the desired temperature in a closed -loop system. Lone Star NGL plans to utilize the hot oil system as needed to provide heat in the Amine Regeneration unit, in the Molecular Sieve regeneration unit, and as needed to various heat exchangers associated with the fractionation process (i.e., piping to maintain desired temperatures on process streams). Both fractionation trains (FRAC I and FRAC II) will have one Hot Oil Heater rated at 270 MMBtu/hr that will support the hot oil system. Additionally, each fractionation train (FRAC I and FRAC II) will utilize a Molecular Sieve regeneration heater that will be rated at 46 MMBtu/hr. The combustion of natural gas in these two heaters will result in combustion-related GHG emissions. All process heaters will be ducted to a common stack that will be equipped with Selective Catalytic Reduction (SCR) technology to significantly reduce NOx emissions.

Lone Star NGL produces a high purity propane product through the use of an export tower to increase propane recovery. This tower uses large amounts of heat, provided by the hot oil heaters, to recover more propane to provide high purity propane. The propane produced through use of an export tower is about 95% propane, whereas conventional fractionation trains without use of such a tower only produce a 90% propane product. The process to produce high purity propane requires more heat capacity than the conventional process, which leads to more GHG emissions than the conventional process. The high purity process produces greater GHG emissions due to the increased heating requirement of the heaters.

An air-assisted flare will be installed at the Mont Belvieu site to control emergency process releases and streams resulting from maintenance, startup, and shutdown (MSS) activities from both FRAC I and FRAC II. No process streams will be routed to the flare during normal operation. Combustion related GHG emissions from the flare will result from the combustion of natural gas fuel to the pilots and combustion of MSS hydrocarbon streams. The flare will have a hydrocarbon destruction and removal efficiency (DRE) of 99%.

Both of the fractionation trains (FRAC I and FRAC II) will utilize a thermal oxidizer (TO) to combust waste gas streams from the process. GHG emissions from the TO will result from waste gas and fuel gas combustion. The waste gas will be converted to CO_2 and water vapor. Both thermal oxidizers will have a hydrocarbon destruction and removal efficiency (DRE) of 99%.

Fugitive emissions of GHG pollutants, including CO_2 and methane, may result from piping equipment leaks. However, very little of these pollutants are contained in the NGL after the amine unit. The piping components that may leak include valves, flanges, pump seals, etc. Lone Star NGL will implement the TCEQ 28LAER Leak Detection and Repair (LDAR) program for the entire Mont Belvieu site.

VII. General Format of the BACT Analysis

The BACT analyses were conducted in accordance with the *"Top-Down" Best Available Control Technology Guidance Document* outlined in the 1990 draft U.S. EPA *New Source Review Workshop Manual*, which outlines the steps for conducting a top-down BACT analysis. Those steps are listed below.

(1) Identify all potentially available control options;

(2) Eliminate technically infeasible control options;

(3) Rank remaining control technologies;

(4) Evaluate the most effective controls and document the results; and

(5) Select BACT.

Also in accordance with the top-down BACT guidance, the BACT analyses also takes into account the energy, environmental, and economic impacts of the control options during step 4. Emission reductions may be determined through the application of available control techniques, process design, and/or operational limitations. Such reductions are necessary to demonstrate that the emissions remaining after application of BACT will not cause adverse environmental effects to public health and the environment.

Each of the emission unit submitted in the PSD GHG application was evaluated separately in the top-down 5-step BACT analysis.

VIII. Applicable Emission Units and BACT Discussion

The majority of the contribution of GHGs associated with the project is from combustion sources (i.e., hot oil heaters, regenerant heaters, thermal oxidizer, and flare)[2]. The site has some fugitive emissions from piping components which contribute a minor amount of GHGs, estimated at 0.03 tpy of the total project CO_2e emissions of 408,662 tpy. Stationary combustion sources primarily emit CO_2, and small amounts of N_2O and CH_4. The following devices are subject to this GHG PSD permit:

- Hot Oil (003-HOHTR and 013-HOHTR) and Molecular Sieve Regenerator (003-RGNHTR and 013-RGNHTR) Heaters
- Thermal Oxidizers (002-THERMO and 012-THERMO)
- Flare (004-FLARE)
- Process Fugitives (009-FUG and 019-FUG)

IX. Plant-wide GHG Controls

Lone Star NGL performed a BACT analysis on GHG control technologies that could be implemented on a plant-wide basis.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Carbon Capture and Storage (CCS)* – CCS is an available add-on control technology that is applicable for all of the sites affected combustion units.
- *Electric Driven Engines* - Electric driven engines are used in place of gas fired engines.
- *Install equipment selected to minimize or remove GHG emissions.*

[2] GHG emissions from the thermal oxidizer include both the CO_2 produced from combustion of H_2S and VOC and the CO_2 contained in the waste gas that arrives from the amine regenerator.

Carbon Capture and Sequestration (CCS)

For purposes of a BACT analysis, CCS is classified as an add-on pollution control technology for “facilities emitting CO_2 in large concentrations, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing).”[3] Lone Star NGL agrees that CCS is an available technology for this facility. For purposes of a BACT analysis, CCS is classified as an add-on pollution control technology. CCS involves the separation and capture of CO_2 from the combustion process flue gas, the captured CO_2 is then pressurized and transportation by pipeline or other means of transportation, if necessary, where it is injected into a long-term geological location. Several technologies are in various stages of development and are being considered for CO_2 separation and capture.

As it stands currently, CCS Technology and its components can be summarized in the table below adopted from IPCC’s *Carbon Dioxide Capture and Storage* report[4]:

CCS Component	CCS Technology
Capture	Post-combustion
	Pre-combustion
	Oxyfuel combustion
	Industrial separation (natural gas processing, ammonia production)
Transportation	Pipeline
	Shipping
Geological Storage	Enhanced Oil Recovery (EOR)
	Gas or oil fields
	Saline formations
	Enhanced Coal Bed Methane Recovery (ECBM)
Ocean Storage	Direct injection (dissolution type)
	Direct injection (lake type)
Mineral carbonation	Natural silicate minerals
	Waste minerals
CO_2 Utilization/Application	Industrial Uses of CO_2 (e.g. carbonated products)

[3]U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011, <http:/www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf> (March 2011)

[4] Intergovernmental Panel on Climate Change (IPCC) Special Report, Bert Metz, Ogunlade Davidson, Heleen de Coninck, Manuela Loos and Leo Meyer (Eds.), *Carbon Dioxide Capture and Storage* (New York: Cambridge University Press, 2005), Table SPM.2, 8. <http://www.ipcc.ch/pdf/special-reports/srccs/srccs_wholereport.pdf>

For large, point sources, there are three types of capture configurations – pre-combustion capture, post-combustion capture, and oxy-combustion capture:

1) Pre-combustion capture implies as named, the capture of CO_2 prior to combustion. It is a technological option available to integrated coal gasification combined cycle (IGCC) plants. In these plants, coal is gasified to form synthesis gas (syngas with key components of carbon monoxide and hydrogen). Carbon monoxide (CO) is reacted with steam to form CO_2 which is then removed and the hydrogen is then diluted with nitrogen and fed into the gas turbine combined cycle.

2) Post-combustion capture involves extracting CO_2 in a purified form from the flue gas following combustion of the fuel. Primarily for coal-fired power plants and electric generating units (EGU), other industries can benefit. Currently, all commercial post-combustion capture is via chemical absorption process using monoethanolamine (MEA)-based solvents.[5]

3) Oxy-combustion technology is primarily applied to coal-burning power plants where the capture of CO_2 is obtained from a pulverized coal oxy-fuel combustion in which fossil fuels are burned in a mixture of recirculated flue gas and oxygen, rather than in air. The remainder of the flue gas, that is not recirculated, is rich in carbon dioxide and water vapor, which is treated by condensation of the water vapor to capture the CO_2.[6] In nearly all existing coal-burning power plants, nitrogen is a major component of flue gas in the boiler units that burn coal in air, post-combustion capture of CO_2 is essentially a nitrogen-carbon dioxide separation which can be done but at a high cost. However if there were no nitrogen present as in the case of oxy-combustion, then CO_2 capture from flue gas would be greatly simplified[7]. It is implied that an optimized oxy-combustion power plant will have ultra-low CO_2 emissions as a result.

Once CO_2 is captured from the flue gas, CO_2 is compressed to 100 atmospheres (atm) or higher for ease of transport (usually by pipeline) into a storage area, in most cases, a geological storage area. It is also possible that CO_2 can be stored and shipped via all different modes of transportation via land, air and sea.

Geological storage of CO_2 involves the injection of compressed CO_2 into deep geologic formations (injection zones) overlain by competent sealing formations and geologic traps that will prevent the CO_2 from escaping. There are five types of geologic formations that are

[5] Wes Hermann et al. *An Assessment of Carbon Capture Technology and Research Opportunities - GCEP Energy Assessment Analysis, Spring 2005*. <http://gcep.stanford.edu/pdfs/assessments/carbon_capture_assessment.pdf>

[6] U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory, "Oxy-Fuel Combustion", August 2008. < http://www.netl.doe.gov/publications/factsheets/rd/R&D127.pdf>

[7] Herzog et al., page 4-5

considered: clastic formations; carbonate formations; deep, unmineable coal seams; organic-rich shales; and basalt interflow zones. There is a large body of ongoing research and field studies focused on developing better understanding of the science and technologies for CO_2 storage.[8]

Electric-Driven Engines

Installing electric driven refrigeration compressor engines in place of gas-fired units can decrease gas losses and methane emissions. Methane emissions from gas-fired engines result from leaks in the gas supply line to the engine, incomplete combustion, and during system upsets. Electric motors reduce the chance of methane leakage by eliminating the need for fuel gas, require less maintenance, and improve operational efficiency.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible. Lone Star NGL claims that CCS is not feasible. EPA disagrees and asserts that CCS is technically feasible for control of CO_2 from the amine units.

Based on the information reviewed for this BACT analysis, while there are some portions of CCS that are technically infeasible, EPA has determined that overall Carbon Capture and Storage (CCS) technology are technologically feasible at this source. Listed below is a summary of those CCS components that are technically feasible and those CCS components that are not technically feasible for Lone Star NGL.

Step Two Summary for CCS for Lone Star NGL

CCS Component	CCS Technology	Technical Feasibility
Capture	Post-combustion	Y
	Pre-combustion	N
	Oxyfuel combustion	N
	Industrial separation (natural gas processing, ammonia production)	Y
Transportation	Pipeline	Y
	Shipping	Y

[8] U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory *Carbon Sequestration Program: Technology Program Plan*, <http://www.netl.doe.gov/technologies/carbon_seq/refshelf/2011_Sequestration_Program_Plan.pdf>, February 2011

CCS Component	CCS Technology	Technical Feasibility
Geological Storage	Enhanced Oil Recovery (EOR)	Y
	Gas or oil fields	N*
	Saline formations	N*
	Enhanced Coal Bed Methane Recovery (ECBM)	N*
Ocean Storage	Direct injection (dissolution type)	N*
	Direct injection (lake type)	N*
Mineral carbonation	Natural silicate minerals	N*
	Waste minerals	N*
Large scale CO_2 Utilization/Application		N*

* Both geologic storage and large scale CO_2 utilization technologies are in the research and development phase and currently commercially unavailable.[9]

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- Electric-driven Engines (100%),
- CO_2 capture and storage (up to 90%).

Use of electric-driven engines reduces CO_2e emissions by 100% when using electricity over natural gas. CO_2 capture and storage is capable of achieving up to 90% reduction of produced CO_2 emissions and thus considered to be the second most effective control method.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Electric-driven Engines

EPA considers the use of electric-driven engines as an appropriate technology to be used at new sources and for modifications. Electric-driven engines are becoming increasingly more available in a larger variety of sizes and capacities.

[9] U.S. Department of Energy, page 20-23

Carbon Capture and Sequestration

EPA considers CCS to be an available control option for high-purity CO_2 streams that merits initial consideration as part of the BACT review process, especially for new facilities. As noted in EPA's GHG Permitting Guidance, a control technology is "available" if it has a potential for practical application to the emissions unit and the regulated pollutant under evaluation. Thus, even technologies that are in the initial stages of full development and deployment for an industry, such as CCS, can be considered "available" as that term is used for the specific purposes of a BACT analysis under the PSD program. In 2010, the Interagency Task Force on Carbon Capture and Storage was established to develop a comprehensive and coordinated federal strategy to speed the commercial development and deployment of this clean coal technology. As part of its work, the Task Force prepared a report that summarized the state of CCS and identified technical and non-technical challenges to implementation.[10] EPA, which participated in the Interagency Task Force, supported the Task Force's conclusion that although current technologies could be used to capture CO_2 from new and existing plants, they were not ready for widespread implementation at all facility types. This conclusion was based primarily on the fact that the technologies had not been demonstrated at the scale necessary to establish confidence in their operations. EPA Region 6 has completed a research and literature review and has found that nothing has changed dramatically in the industry since the August 2010 report and there is no specific evidence of the feasibility and cost-effectiveness of a full scale carbon capture system for the project and equipment proposed by Lone Star NGL.

Lone Star NGL 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. As explained more fully below, EPA has reviewed Lone Star NGL's CCS analysis and has determined that CCS is not economically feasible at this time for this application and also has negative environmental and energy impacts, and has eliminated CCS as a potential BACT option.

The analysis provided by the applicant demonstrates that CCS can be eliminated based on its economic, environmental, and energy costs. In its analysis, Lone Star NGL noted that it is in relatively close proximity to a CO_2 pipeline. The nearest existing pipeline identified by Lone Star NGL that may transport CO_2 is approximately 35 miles from the plant. The distance to the pipeline is calculated approximately based on location of Denbury Green Pipeline located in Chambers County as seen from the National Pipeline Mapping System.[11] Lone Star NGL utilized

[10] See *Report of the Interagency Task Force on Carbon Capture and Storage* available at http://www.epa.gov/climatechange/policy/ccs_task_force.html
[11] http://www.npms.phmsa.dot.gov/

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*[12] 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 CO_2 to the pipeline is well over $55,000,000. The total pipeline annualized cost for CCS over the 10 year expected life of the equipment is $8,470,000 per year.[13]

To process the 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 an additional 100 MMSCFD amine unit, cryogenic units, dehydration units, and associated equipment greater than the size of the proposed plant. The estimated cost of the additional equipment is over $25,000,000. The exhaust/waste gas stream would need to be compressed to send it to the amine unit for CO_2 separation. It is estimated that 6 Caterpillar 3616 engines would be needed to produce 28,000 hp. Each 3616 engine will generate nearly 20,000 TPY CO_2 for a total of 120,000 tons of CO_2 just from the compression process to the dedicated amine unit. 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. Moreover, as explained below, the electricity required to run additional equipment is not available at the site, therefore additional natural gas fired generators would be required. These additional generators fuel consumption and resultant combustion-related emissions would be even greater than emissions from the proposed project and would emit additional GHG emissions of approximately 250,000 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.

The addition of CCS to the project would increase the project costs by 25% from $323,000,000 to $403,000,000. As explained above, EPA Region 6 reviewed Lone Star NGL'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 Lone Star NGL CCS should be eliminated as BACT for this facility due to the economic impacts and negative environmental and energy impacts.

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[12] 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
[13] See the CCS cost analysis at Tables B-1, B-2, and B-3 of the permit application.

Step 5 – Selection of BACT

The only BACT practice selected for site-wide implementation is the use of electric-driven engines for refrigeration compression. Although the selected BACT does not correlate to a numerical limit, it does result in a permit condition which requires the company to install and operate electric driven engines for refrigeration compression.

X. Hot Oil (003-HOHTR and 013-HOHTR) and Molecular Sieve Regeneration Heater (003-RGNHTR and 013-RGNHTR)

Each fractionation train (FRAC I and FRAC II) has one hot oil heater (003-HOHTR and 013-HOHTR) rated at 270 MMBtu/hr and one molecular sieve regenerator heater (003-RGNHTR and 013-RGNHTR) rated at 46 MMBtu/hr. The hot oil heater provides heat to the amine regeneration unit, molecular sieve regeneration unit, and as needed to various heat exchangers associated with the fractionation process. Heat needed for the molecular sieve is provided by the molecular sieve regeneration gas heater.

As part of the PSD review, Lone Star NGL provides in the GHG permit application a 5-step top-down BACT analysis for the heaters. EPA has reviewed Lone Star NGL's BACT analysis for the heaters, finds it sufficient, and adopts it in setting forth this proposed permit, as summarized below.

Step 1 – Identification of Potential Control Technologies

- *Combustion Air Controls* – Excessive combustion air reduces the efficiency of the hot oil heater burners.
- *Periodic Tune-up* – Periodically tune-up the heaters to maintain optimal thermal efficiency..
- *Heater Design* – Good heater design to maximize thermal efficiency.
- *Fuel Selection/switching* – Use of low carbon fuels results in lower GHG emissions.
- *Fuel Gas Preheating*– Preheating the fuel stream reduces the heating load, increases thermal efficiency and, therefore, reduces emissions.
- *Heat Recovery* – Use of heat recovery from the hot effluent from the hot oil heater in the primary and secondary heat exchangers. Tertiary exchangers also recover heat and contribute to overall energy efficiency.
- *Proper Operation and Good Combustion Practices* – The formation of GHGs can be controlled by proper operation and using good combustion techniques.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible, except for fuel gas preheating for the Regeneration Heaters. For the Regeneration Heaters, preheating the fuel gas is not feasible due to the size of the heater (<100 MMBtu/hr). For the Hot Oil Heaters, fuel gas preheating is not considered feasible since it shares a fuel gas feed line with the Regeneration Heaters.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- Fuel Selection/switching (28%).
- Periodic Tune-up (1-10%).
- Combustion Air Controls (1-3%)
- Heater Design (not quantifiable)
- Heat Recovery (does not directly improve heater efficiency)
- Proper Operation and Good Combustion Practices(not quantifiable)

Good heater design, air/fuel ratio control, and periodic tune-ups are all considered effective and have a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only. The estimated efficiencies were obtained from the *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry*, issued by EPA in October 2010.[14] Product heat recovery involves the use of heat exchangers to transfer the excess heat that may be contained in product streams to feed streams.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Fuel Selection Switching

Firing a low carbon fuel reduces the CO_2 production form combustion. Natural gas is the lowest carbon fuel available for use in the proposed heaters. Natural gas is a very clean burning fuel with respect to criteria pollutants and thus has minimal environmental impact compared to other fuels.

Periodic Tune-up

Periodic tune-ups of the heaters include:

[14] Available at http://www.epa.gov/nsr/ghgdocs/refineries.pdf

- Preventative maintenance check of fuel gas flow meters annually,
- Preventative maintenance check of oxygen control analyzers quarterly,
- Cleaning of burner tips on an as-needed basis, and
- Cleaning of convection section tubes on an as-needed basis.

These activities insure maximum thermal efficiency is maintained; however, it is not possible to quantify an efficiency improvement, although convection cleaning has shown improvements in the 0.5 to 1.5% range, and routine and proper maintenance can theoretically recover up to 10% of the efficiency lost overtime to age.

Combustion Air Controls

Some amount of excess air is required to ensure complete fuel combustion, minimize emissions, and for safety reasons. More excess air than needed to achieve these objectives reduces overall heater efficiency. Manual or automated air/fuel ratio controls is used to optimize these parameters and maximize the efficiency of the combustion process. Automated controls are considered more efficient than manual controls.

Heater Design

New heaters can be designed with efficient burners, more efficient heat transfer efficiency to the hot oil and regeneration streams, state-of-the-art refractory and insulation materials in the heater walls, floor, and other surfaces to minimize heat loss and increase overall thermal efficiency.

Heat Recovery

Rather than increasing heater efficiency, the technology reduces potential GHG emissions by reducing the required heater duty (fuel firing rate), which can substantially reduce overall plant energy requirements.

Proper Operation and Good Combustion Practices

Proper operation and good combustion practices for the heaters include:
Rather than increasing heater efficiency, the technology reduces potential GHG emissions by reducing the required heater duty (fuel firing rate), which can substantially reduce overall plant energy requirements.

Step 5 – Selection of BACT

To date, other similar facilities with a GHG BACT limit are summarized in the table below:

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
Energy Transfer Company (ETC), Jackson County Gas Plant Ganado, TX	Four Natural Gas Processing Plants	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT limit for process heaters of 1,102.5 lbs CO_2/MMSCF 365-day average, rolling daily for each plant Fugitive methane emissions are monitored and maintained using best practice standards.	2012	PSD-TX-1264-GHG

The following specific BACT practices are proposed for the furnace:

- *Heater design* – The hot oil heaters and regeneration heaters shall be designed to achieve high thermal efficiencies.
- *Heater design* – Burner design improves the mixing of fuel, creating a more efficient heat transfer. Lone Star NGL will utilize a burner management system on the heaters, such that intelligent flame ignition, flame intensity controls, and flue gas recirculation optimize the efficiency of the devices.
- *Periodic Tune-up* – Clean burner tips and convection tubes as needed, but to occur no less frequently than every 12 months.
- *Combustion Air Controls* – Oxygen monitors and intake air flow monitors can be used to optimize the fuel/air mixture and limit excess air to 15%.
- *Fuel Selection/switching* – Lone Star NGL will be firing only pipeline quality natural gas, which results in 28% less CO_2 production than fuel oils.
- *Heat Recovery* – Use of heat recovery from the hot effluent from the hot oil heater in the primary and secondary heat exchangers. Tertiary exchangers also recover heat and contribute to overall energy efficiency. The combustion convection section is used to preheat the hot oil to the extent that the final exiting flue gas temperature is reduced to its practical limit, minimum 500 ^{o}F.

- *Proper Operation and Good Combustion Practices* – Proper operation involves providing the proper air-to-fuel ratio, residence time, temperature, and combustion zone turbulence essential to maintain low GHG emissions. Good combustion techniques include: operator practices; maintenance knowledge; and maintenance practices.

<u>BACT Limits and Compliance:</u>

Using the BACT practices above will result in an output based BACT limit for the heaters based on the barrels (bbl) per day of natural gas liquids processed.

The Hot Oil Heaters shall have a 2,759 lbs CO_2/barrel (bbl) processed BACT limit. The Regeneration Heaters shall have a 470 lbs CO_2/bbl processed BACT limit. Compliance will be determined for both limits on a 365 day rolling average.

Both the hot oil and regenerant heaters will be designed to incorporate efficiency features, including insulation to minimize heat loss and heat transfer components that maximize heat recovery while minimizing fuel use. Lone Star NGL will maintain records of heater tune-ups, burner tip maintenance, O_2 analyzer calibrations and maintenance for all heaters.

Lone Star NGL will demonstrate compliance with the CO_2 limits for the heaters using the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-2. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(3)(iii) is as follows:

Where:

CO_2 = Annual CO_2 mass emissions from combustion of natural gas (short tons)
Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i).
CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV at §98.33(a)(2)(ii).
MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedure as specified for HHV at §98.33(a)(2)(ii).
MVC = Molar volume conversion factor at standard conditions, as defined in §98.6.
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion of kg to metric tons.
1.102311 = Conversion of metric tons to short tons.

The proposed permit also includes an alternative compliance demonstration method, in which Lone Star NGL may install, calibrate, and operate a CO_2 Continuous Emission Monitoring System (CEMS) and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions.

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). Comparatively, the emissions from CO_2 contribute the greatest (greater than 99%) to the overall emissions from the heaters and; therefore, additional analysis is not required for CH_4 and N_2O. 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 average, rolling daily.

An initial stack test demonstration will be required for CO_2 emissions from each emissions unit. An initial stack test demonstration for CH_4 and N_2O emissions are not required because the CH_4 and N_2O emissions are less than 0.01% of the total CO_2e emissions from the heaters and are considered a *de minimis* level in comparison to the CO_2 emissions.

XI. Flare (004-FLARE)

The FRAC I and FRAC II units will utilize a flare (004-FLARE) for control of MSS emissions and emergency process releases. The flare's pilots are fueled by pipeline quality natural gas. The pilot gas flow rate is 200 scfh. The flare will have a hydrocarbon destruction and removal efficiency (DRE) of 99%.

Step 1 – Identification of Potential Control Technologies

- *Proper Operation and Good Combustion Practices* – Use of flow and composition monitors to accurately determine the optimum amount of natural gas required to maintain adequate VOC destruction in order to minimize natural gas combustion and the resulting CO_2.
- *Fuel Selection* – Use of low carbon fuels such as natural gas, which represents the available pilot and supplemental fuel type with the lowest carbon intensity on a heat input basis.
- *Minimize Duration of MSS Activities* – Minimize the duration and quantity of MSS flaring to the extent possible through good engineering design of the process and good operating practices.
- *Flare Gas Recovery* – A flare gas recovery compressor system can be used to recover flared gas to the fuel gas system.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible, except for flare gas recovery. The flare is not a process flare, but an intermittent use MSS flare. Therefore, no continuous stream (other than pilot gas) is being combusted, and flare gas recovery is infeasible to implement.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Flare minimization, proper operation and good combustion practices for the flare are potentially equally effective but have case-by-case effectiveness that cannot be quantified to allow ranking. However, such ranking is not necessary since each of these technologies is already proposed for use at the project.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Use of an analyzer(s) to determine the heating value of the gas to allow continuous determination of the amount of natural gas needed to maintain a minimum heating value of 300 Btu/scf to insure proper destruction of VOCs ensures that excess natural gas is not unnecessarily flared. This added advantage of reducing fuel costs makes this control option cost effective as both a criteria pollutant and GHG emission control option. There are no negative environmental impacts associated with this option. Proper design of the process equipment to minimize the quantity of waste gas sent to the flare also has no negative economic or environmental impacts.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the low profile flare:

- *Proper Operation and Good Combustion Practices* **–** The formation of GHGs can be controlled by proper operation and using good combustion practices. Poor flare combustion efficiencies lead to higher methane emissions and higher overall GHG emissions. Lone Star NGL will monitor the BTU content on the flared gas, and will have air assisted combustion allowing for improved flare gas combustion control and minimizing periods of poor combustion. Periodic maintenance will help maintain the efficiency of the flare.
- *Fuel Selection* – Lone Star NGL will utilize pipeline quality natural gas in the pilots of the flare.
- *Minimize Duration of MSS Activities* – Minimize outage time of the Y-grade deethanizer and coordinate inlet filter change outs, pump/compressor maintenance, and meter recalibration in order to minimize flaring events.

Using these BACT practices above will result in a BACT limit for the low profile flare of 52 tpy CO_2e.

XII. Thermal Oxidizers (002-THERMO and 012-THERMO)

Each fractionation unit (FRAC I and FRAC II) will utilize a thermal oxidizer (002-THERMO and 012-THERMO) for control of waste gas streams. GHG emissions from the thermal oxidizers will result from waste gas and fuel gas combustion. The thermal oxidizer will have a hydrocarbon destruction and removal efficiency (DRE) of 99%.

Step 1 – Identification of Potential Control Technologies

- *Use of Standard Thermal Oxidizers* **–** Use of thermal oxidizers for control of emissions.
- *Use of Other Planned Combustion Processes Over a Separate Thermal Oxidizer* - Use of existing combustion processes (e.g. flare or heaters) over a separate thermal oxidizer.
- *Proper Design, Operation, and Good Combustion Practices* **–** Periodic maintenance will help maintain the efficiency of the thermal oxidizer. Temperature monitoring will ensure proper thermal oxidizer operation.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible, except for use of other planned combustion processes over a separate thermal oxidizer. It is not technically feasible to use the flare in lieu of the thermal oxidizer for normal operation (only upset conditions), because the flare cannot handle the volume of waste streams to be routed to the thermal oxidizer. The flare is for intermittent use only, for combusting intermittent MSS streams. Further, the waste stream has a very low heat content (<100 Btu/scf). Therefore, it is not feasible to send this stream to the proposed heaters as the stream will not combust properly and could cause mechanical problems within that heater causing inefficient operation.

Because the remaining technologies are already proposed for use at the project, ranking by effectiveness (Step 3) and a subsequent evaluation of each technology (Step 4) was not considered necessary for the BACT determination.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Not Applicable (as noted above)

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Not Applicable (as noted above)

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the thermal oxidizer:

- *Use of Standard Thermal Oxidizers* – Lone Star NGL will be utilizing standard thermal oxidizers with a 99% DRE for VOC. This type of thermal oxidizer will be used to meet stringent VOC control requirements for the Houston-Galveston-Brazoria "severe" ozone non-attainment area.
- *Proper Design, Operation, and Good Combustion Practices* – Periodic maintenance will help maintain the efficiency of the thermal oxidizer. Temperature monitoring will ensure proper thermal oxidizer operation.

Using these BACT practices above will result in a BACT limit for each thermal oxidizer of 42,703 tpy CO_2e.

XIII. Process Fugitives (009-FUG and 019-FUG)

Hydrocarbon emissions from leaking piping components (process fugitives) associated with the proposed project include methane, a GHG. The additional methane emissions from process fugitives have been conservatively estimated to be 0.03 tpy as CO_2e. Fugitive emissions of methane are negligible, and account for less than 0.01% of the project's total CO_2e emissions.

Step 1 – Identification of Potential Control Technologies for GHGs

The only identified control technology for process fugitive emissions of CO_2e is use of a leak detection and repair (LDAR) program. LDAR programs vary in stringency as needed for control of VOC emissions; however, due to the negligible amount of GHG emissions from fugitives, LDAR programs would not be considered for control of GHG emissions alone. As such, evaluating the relative effectiveness of different LDAR programs is not warranted.

Step 2 – Elimination of Technically Infeasible Alternatives

LDAR programs are a technically feasible option for controlling process fugitive GHG emissions.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

As stated in Section XI, Step 1, this evaluation does not compare the effectiveness of different levels of LDAR programs.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Although technically feasible, use of an LDAR program to control the negligible amount of GHG emissions that occur as process fugitives is clearly cost prohibitive. However, if an LDAR program is being implemented for VOC control purposes, it will also result in effective control of the small amount of GHG emissions from the same piping components. Lone Star NGL uses TCEQ's 28LAER[15] LDAR program at the Mont Belvieu Complex to minimize process fugitive VOC emissions at the plant, and this program has also been proposed for the additional fugitive VOC emissions associated with the project. 28LAER is TCEQ's most stringent LDAR program, developed to satisfy LAER requirements in ozone non-attainment areas.

Step 5 – Selection of BACT

EPA has reviewed and concurs with Lone Star NGL's Fugitive Emission Sources BACT analysis. Based on Lone Star NGL's top-down BACT analysis for fugitive emissions, Lone Star NGL concludes that using the TCEQ 28 LAER[16] leak detection and repair (LDAR) program is the appropriate BACT control technology option. Lone Star NGL also identified and adopted the use of dry compressor seals, use of rod packing, 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. As noted above, LDAR programs would not normally be considered for control of GHG emissions alone due to the negligible amount of GHG emissions from fugitives, and while the existing LDAR program is being imposed in this instance, the imposition of a numerical limit for control of those neglible emissions is not feasible.

XIV. 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

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[15] 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.

[16] 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.

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 Lone Star NGL Mont Belvieu, L.P. ("Lone Star") and its consultant, URS, Inc., as non-federal representatives for purposes of preparation of the BA and for conducting informal consultation.

A draft BA has identified ten (10) species as endangered or threatened in Chambers County, Texas by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS) and the Texas Parks and Wildlife Department (TPWD) and is listed in the table below:

Federally Listed Species for Harris County	Scientific Name	Identifying Agency
Smalltooth Sawfish	*Pristis pectinata*	NMFS/TPWD
Green Sea Turtle	*Chelonia mydas*	USFWS/NMFS/TPWD
Kemp's Ridley Sea Turtle	*Lepidochelys kempii*	USFWS/NMFS/TPWD
Leatherback Sea Turtle	*Dermochelys coriacea*	USFWS/NMFS/TPWD
Loggerhead Sea Turtle	*Caretta caretta*	USFWS/NMFS/TPWD
Hawksbill Sea Turtle	*Eretmochelys imbricate*	USFWS/NMFS/TPWD
Louisiana Black Bear	*Ursus americanus luteolus*	TPWD
Red Wolf	*Canis rufus*	TPWD
Piping Plover	*Charadrius melodus*	USFWS/TPWD
Sprague's pipit*	*Anthus spragueii*	USFWS

*Sprague's' pipit is listed as a candidate species by USFWS

EPA has determined that the proposed permit will have no effect on any of the ten (10) listed species, as the occurrence of any of these species within the action area of the facility is highly improbable. The action area for this project based on air modeling was determined to be the property itself that is comprised of three tracts of land covering a total of approximately 70.8 acres within an industrialized area. The piping plover and Sprague's pipit do not have suitable habitat within the action area, and are highly unlikely to occur in the vicinity of the Project. The green sea turtle, hawksbill sea turtle, Kemp's ridley sea turtle, leatherback sea turtle, loggerhead sea turtle, and smalltooth sawfish are marine species and would not occur near the Project; these species are also not expected to be impacted indirectly, or through impacts to water quality. The Louisiana black bear, and red wolf are not found in the vicinity of the action area, and would not be impacted by the Project. The action area does not include any essential fish habitat or designated critical habitat for federally listed threatened or endangered species, and the Texas Natural Diversity Database includes no elements of occurrence for any rare, threatened, or endangered species. Indirect effects resulting from emissions, such as acidification and eutrophication, are unlikely to occur; therefore, protected species and their habitats will not likely be impacted.

Because of EPA's "no effect" determination, no further consultation with the USFWS and NMFS is needed.

XV. National Historic Preservation Act (NHPA)

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties eligible or potentially eligible for inclusion in the National Register of Historic Places. To make this determination, EPA relied on a cultural resource report prepared by URS, Lone Star NGL's consultant, submitted on July 24, 2012.

URS conducted an archaeological survey within a one (1) mile area of review around the construction site. This included a review of information in Texas Historical Commission's Restricted Archaeological Sites Atlas and the National Park Service's National Register of Historic Places (NHRP) URS performed a pedestrian survey of the site that covered a combined 74 acres and included 47 shovel tests at the site of construction.

The project site itself has been subject to many disturbances associated with previous construction activities related to oil and gas industry as well as agricultural activities that include construction of berms and irrigation ditches. The project site is 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. Finally, the property is not of exceptional significance.

Based on the information provided in the cultural resources report, three historic sites were found within the 1-mile radius, they were the First United Methodist Church and Cemetery of Mont Belvieu originally known as Barbers Hill, the Williams Cemetery and the Fisher Cemetery. All were found within1.0 mile from the project site. These three historic sites are not listed on the National Register, but EPA determines that the three sites are potentially eligible for inclusion in the National Register because each of these properties meets the certain criteria for inclusion in the National Register listed in 36 CFR 60.4.

EPA Region 6 preliminarily determines that this project will have no adverse effects on the three nearby cemeteries which are properties potentially eligible for the National Register. The project does not alter, directly or indirectly any of of the characteristics of the historic properties that would diminish the integrity of the property's location, design, setting, materials, workmanship, feeling or association. This is because the project site is located nearly 1.0 mile away from all of the historic sites and the airborne pollution generated from construction activities, increased traffic, and facility emissions are not likely to impact the three properties based on the air modeling data. In addition, the project will not visually impact any of the three sites as it is located a highly industrialized area with other existing facilities.

EPA will provide a copy of the report and consult with the Texas State Historical Preservation Officer (SHPO), and interested Indian tribes or other parties, as required. In addition, any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties. A copy of the report will be available on the EPA Region 6 website at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XVI. Environmental Justice (EJ)

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive branch policy on environmental justice. Based on this Executive Order, the EPA's Environmental Appeals Board (EAB) has held that environmental justice issues must be considered in connection with the issuance of federal Prevention of Significant Deterioration (PSD) permits issued by EPA Regional Offices [See, e.g., *In re Prairie State Generating Company*, 13 E.A.D. 1, 123 (EAB 2006); *In re Knauf Fiber Glass*, Gmbh, 8 E.A.D. 121, 174-75 (EAB 1999)]. This permitting action, if finalized, authorizes emissions of GHG, controlled by what we have determined is the Best Available Control Technology for those emissions. It does not select environmental controls for any other pollutants. Unlike the criteria pollutants for which EPA has historically issued PSD permits, there is no National Ambient Air Quality Standard (NAAQS) for GHG. The global climate-change inducing effects of GHG emissions, according to the "Endangerment and Cause or Contribute Finding", are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible [PSD and Title V Permitting Guidance for GHGs at 48]. Thus, we conclude it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit. Accordingly, we have determined an environmental justice analysis is not necessary for the permitting record.

XVII. Conclusion and Proposed Action

Based on the information supplied by Lone Star NGL, our review of the analyses contained the TCEQ Standard 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 Lone Star NGL 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 365-day total, rolled daily, shall not exceed the following:

Table 1. Facility Emission Limits[1]

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
003-HOHTR	003-SCR	FRAC I Hot Oil Heater	CO_2	137,943	138,078	2,759 lb CO_2/bbl of NGL processed. See permit condition III.B.2.a.
			CH_4	2.6		
			N_2O	0.26		
013-HOHTR	013-SCR	FRAC II Hot Oil Heater	CO_2	137,943	138,078	2,759 lb CO_2/bbl of NGL processed. See permit condition III.B.2.b.
			CH_4	2.6		
			N_2O	0.26		
003-RGNHTR	003-RV	FRAC I Regenerator Heater	CO_2	23,501	23,524	470 lbs CO_2/bbl of NGL processed. See permit condition III.B.2.c.
			CH_4	0.44		
			N_2O	0.04		
013-RGNHTR	013-RV	FRAC II Regenerator Heater	CO_2	23,501	23,524	470 lbs CO_2/bbl of NGL processed. See permit condition III.B.2.d.
			CH_4	0.44		
			N_2O	0.04		
004-FLARE	004-FLARE	Flare	CO_2	52	52	Good combustion practices. See permit condition III.D.1.f.
			CH_4	negligible		
			N_2O	negligible		
002-THERMO	002-THERMO	FRAC I Thermal Oxidizer	CO_2	36,406	42,703	Good combustion practices, and annual compliance testing. See permit conditions III.C.1.c. through III.C.1.j.
			CH_4	0.18		
			N_2O	0.02		
012-THERMO	012-THERMO	FRAC II Thermal Oxidizer	CO_2	36,406	42,703	Good combustion practices, and annual compliance testing. See permit conditions III.C.1.c. through III.C.1.j.
			CH_4	0.18		
			N_2O	0.02		
019-FUG	019-FUG	Fugitive Process Emissions	CH_4	Not Applicable	Not Applicable	Implementation of LDAR Program. See permit condition III.E.1.d.
Totals[4]			**CO_2**	**395,752**	**CO_2e 408,662**	
			CH_4	**6.44**		
			N_2O	**0.64**		

1. Compliance with the annual emission limits (tons per year) is based on a 365-day total, rolled daily.
2. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities.
3. Global Warming Potentials (GWP): CH_4 = 21, N_2O = 310
4. The total emissions for CH_4 and CO_2e include the PTE for process fugitive emissions of CH_4. These totals are given for informational purposes only and do not constitute emission limits.

Heater BACT Limits

The following is to demonstrate how the heater BACT limits were established.

The TPY of CO_2 for the heaters was converted to pounds (lbs) per year.

Example:

The lbs per year of CO_2 was then divided by the processing rate for the fractionation train of 100,000 barrels (bbl) per day to give a BACT limit of lbs CO_2/bbl processed.

Example: