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Additional Response to EPA questions on GHG PSD application - Lone Star, Mont Belvieu - Frac II

James Smith to: Aimee Wilson 05/24/2012 04:19 PM

Cc: "Weiler, Jeff", Vikram Kashyap , Deever Bradley

History: This message has been forwarded.

1 attachment

3417BR-Addendum.pdf

Aimee, on behalf of Energy Transfer, ERM submits this additional response to your technical review questions regarding the GHG PSD application for Lone Star's Mont Belvieu Frac II project. We believe these responses address your questions. Please respond with questions.

Best regards,

James Smith
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Energy Transfer Partners, L.P. dba Lone Star NGL, LLC
Greenhouse Gas PSD Permit Application
ADDENDUM 1

This Addendum 1 to the GHG PSD permit application, submitted to EPA Region 6 on December 7, 2011, clarifies the changes in emissions between the originally authorized FRAC I train and the "as built" FRAC I train, for Non-attainment New Source Review (NNSR) and Greenhouse Gas Prevention of Significant Deterioration (GHG PSD) review.

NNSR Review

The original FRAC I emission sources were authorized via a TCEQ Standard Permit for Oil and Gas Facilities (30 TAC §116.620), issued to LDH Energy on December 13, 2010. Since the issuance of that permit, Energy Transfer Partners purchased LDH Energy's Mont Belvieu facility, and re-designed the FRAC I train for specific emission sources. The following table shows the changes between the original FRAC I emissions (2010) and the "as built" FRAC I emissions of VOC and NO_X for these specific sources. Note that the originally authorized Flare source (which will service both FRAC I and FRAC II trains) and the Miscellaneous Maintenance source have not been revised, so the emissions from these sources did not change with the FRAC I train re-design.

Comparison Between Original FRAC I Emissions and "As Built" FRAC I Emissions for VOC and NO_X (tpy)

	VOC	NO_X
Original FRAC I (2010)		
Heaters	7.51	13.93
Thermal Oxidizer	0.01	0.16
Cooling Tower	5.52	---
Tanks	0.03	---
As Built FRAC I		
Heaters	7.47	13.84
Thermal Oxidizer	10.53	4.85
Cooling Tower *	0	---
Tanks	0.06	---
Change from Original to As Built		
Heaters	-0.04	-0.09
Thermal Oxidizer	10.52	4.69
Cooling Tower	-5.52	---
Tanks	0.03	---
Total Change	**4.99**	**4.60**

* The original cooling water tower has been replaced with a vapor mist cooling water heat exchange system. Due to its design, the vapor mist heat system is not expected to have air pollutant emissions.

As shown in Table A-1(a) of the Standard Permit application for FRAC II, submitted to the TCEQ in mid-January 2012, the total VOC and NO_X emissions increase due to the FRAC II project are 18.13 tons per year (tpy) and 18.74 tpy, respectively. When the above emission changes for FRAC I are added to the FRAC II emissions increase, the total VOC and NO_X emissions increases are 23.12 tpy and 23.34 tpy, respectively. Each total is below the 25 tpy emissions increase threshold for triggering NNSR for modification projects in the Houston-Galveston-Brazoria "severe" ozone non-attainment area. Therefore, the Lone Star Mont Belvieu FRAC II project is a minor modification, and the NNSR program does not apply.

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GHG PSD Review

As stated in the Introduction (Section 1.0) of the GHG PSD application, the initial Standard Permit for the existing gas plant (FRAC I) was issued on December 13, 2010, prior to implementation of the PSD Tailoring Rule (which became effective January 2, 2011). Construction for FRAC I was started prior to July 1, 2011. The FRAC I project, therefore, was not subject to the PSD Tailoring Rule, and GHG emissions were not estimated for FRAC I sources at the time of the original application.

In response to EPA's recent request, GHG emissions were estimated for the original FRAC I heater and thermal oxidizer and compared to the "as built" FRAC I heaters and thermal oxidizer, where the "as built" FRAC I GHG emissions were assumed to be equal to the FRAC II GHG emissions. The following table shows this comparison.

Comparison Between Original FRAC I Emissions and "As Built" FRAC I Emissions for GHG (tpy)

	CH_4	N_2O	CO_2	CO_2e *
Original FRAC I (2010)				
Heater	3.06	0.31	162,454.55	162,613.88
Thermal Oxidizer	0.01	0.00	4,751.04	4,751.35
As Built FRAC I **				
Heaters	3.04	0.30	161,444.63	161,602.96
Thermal Oxidizer	0.18	0.02	42,693.42	42,702.64
Change from Original to As Built				
Heaters	-0.02	-0.01	-1,009.93	-1,010.92
Thermal Oxidizer	0.17	0.02	37,942.38	37,951.29
Total Change	**0.15**	**0.01**	**36,932.46**	**36,940.37**

* Value incorporates Global Warming Potential (GWP) of the individual GHG

** Assumes values equal to FRAC II GHG emission rates

The following table shows the total GHG emissions that result from adding the change in GHG emissions going from the original FRAC I design to the "as built" FRAC I design with the estimated FRAC II GHG emissions.

Total GHG Emissions From Adding FRAC I Change to FRAC II (tpy)

	CH_4	N_2O	CO_2	CO_2e *
Change in FRAC I Emissions	0.15	0.01	36,932.46	36,940.37
FRAC II Emissions	3.22	0.32	204,138.05	204,305.60
Total	**3.37**	**0.33**	**241,070.51**	**241,245.97**

As described in the GHG PSD application, the existing Mont Belvieu gas plant is considered a major GHG source because its site-wide potential GHG emissions are greater than the applicable thresholds of 100,000 tpy on a CO_2e-basis and 250 tpy on a mass basis under Step 2 of the Tailoring Rule. The FRAC II project is considered a major modification to the existing site, and thus subject to federal PSD review, because it will have a net increase of GHG emissions above the modification applicability threshold of 75,000 tpy CO_2e.

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Energy Transfer Partners, L.P. dba Lone Star NGL, LLC
Greenhouse Gas PSD Permit Application
ADDENDUM 2

This Addendum 2 to the GHG PSD permit application, submitted to EPA Region 6 on December 7, 2011, addresses (1) BACT for the as-built FRAC I emissions sources and (2) the requirement to address Additional Impacts for a PSD permit application. For the FRAC II project, the only PSD pollutant is Greenhouse Gas (GHG).

BACT for As Built FRAC I Sources

The FRAC 1 as-built sources are similar in design and operation to the FRAC II sources. Therefore, the GHG BACT analysis and limits proposed for the applicable FRAC II sources shall also apply to the as-built FRAC I sources.

Additional Impacts

An additional impacts analysis was not included in the FRAC II GHG PSD application based upon the EPA's recommendation outlined in their November 2010 guidance document, *PSD and Title V Permitting Guidance for Greenhouse Gases* (Page 49). The EPA believes it is not necessary for applicants or permitting authorities to assess impacts from GHGs in the context of the additional impacts analysis or Class I area provisions of the PSD regulations because of the scale of GHG impacts to the environment. Although it is clear that GHG emissions contribute to global warming and other climate changes that result in impacts on the environment, climate change modeling and evaluations of risks and impacts of GHG emissions are typically conducted for changes in emissions 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 with current climate change modeling.

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Revised Addendum 2

Weiler, Jeff to: Aimee Wilson 06/05/2012 08:28 AM
Cc: "'Wilkins, Tim'", 'James Smith'

History: This message has been replied to and forwarded.

1 attachment

TX_MONT BELVIEU FRACII_EPA GHG PSD Addendum2_120605.DOC

Attached is the updated addendum to address the additional impacts. Let me know if this is acceptable.

Regards,
Jeff Weiler
Energy Transfer Company
Environmental Manager
210-403-7323 Office
210-289-4550 Cell
210-403-7523 Fax

Energy Transfer Partners, L.P. dba Lone Star NGL, LLC
Greenhouse Gas PSD Permit Application
ADDENDUM 2

This Addendum 2 to the GHG PSD permit application submitted to EPA Region 6 on December 7, 2011, addresses (1) BACT for the as-built FRAC I emissions sources and (2) Additional Impacts for a PSD permit application. For the FRAC II project, the only PSD pollutant is Greenhouse Gas (GHG).

BACT for As Built FRAC I Sources

The FRAC 1 as-built sources are similar in design and operation to the FRAC II sources. Therefore, the GHG BACT analysis and limits proposed for the applicable FRAC II sources shall also apply to the as-built FRAC I sources.

Additional Impacts

EPA's November 2010 guidance document, *PSD and Title V Permitting Guidance for Greenhouse Gases* (Page 49), is clear that EPA does not require applicants or permitting authorities to perform an additional impact analysis or address the Class I area provisions of the PSD regulations when GHGs are the sole pollutants being permitted, as in this permitting action. We understand from a phone conversation with EPA Region 6 that an internal workgroup at EPA changed this directive and EPA now seeks additional impact analyses of PSD pollutants even when GHGs is the only pollutant being permitted. Region 6's change to the widely distributed and well-know GHG guidance issued by EPA Headquarters must go through proper notice and comment rulemaking. While we contest EPA's Region 6 request and the new directive as being contrary to the purpose of EPA-issued guidance and the protections afford by notice and comment rulemaking requirements, Lone Star nonetheless provides the requested information.

The additional impact analyses provision in 40 CFR §51.21(o) request that the permit application provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the source or modification and general commercial, residential, industrial and other growth associated with the source or modification. The permittee does not need provide an analysis of the impact on vegetation having no significant commercial or recreational value. Additionally, under §51.21(o)(2), the applicant should provide an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial and other growth associated with the source or modification. Finally, under §51.21(o)(3), the permittee may need to address visibility in any Federal Class I area near the proposed new stationary source for major modification as necessary and appropriate.

The emissions increase of NO_x, VOC, CO, SO_2, and $PM_{10/2.5}$ associated with the FRAC II project are considered to have insignificant impacts under both the PSD and Nonattainment NSR programs to the environment surrounding the Mont Belvieu site. Potential increases are regulated and governed by the EPA-approved minor source permitting programs in Texas. In approving these programs, EPA made a determination that permits issued to minor sources of PSD pollutants are protective of the National Ambient Air Quality Standards and general air quality. Because the FRAC II project potential emission increases of non-GHG pollutants are being permitted under EPA's approved minor source permitting program, significant impairment to soils and vegetation is not expected. Furthermore, the Mont Belvieu site is located in an industrial area where there is no vegetation having significant commercial or recreational value. Almost the entire GHG emissions from the proposed FRAC II project will be made up of carbon dioxide (CO_2), with very small amounts of methane (CH_4) and nitrous oxide (N_2O). Because the effects of GHG emissions are typically evaluated on a global scale (i.e., for global warming), and because CO_2 actually benefits vegetation (i.e., plants take in CO_2 to produce oxygen), impairment to soils and vegetation due to GHG is not expected. See "Endangered Species Act and GHG Emitting Activities," Robert J. Meyers, USEPA Office of Air and Radiation, October 3, 2008.

Lone Star does not expect any significant commercial or residential growth associated with the project. Employment at the Mont Belvieu facility is expected to total approximately 40 - 50 personnel once the facility becomes fully operational. No significant impact on local air quality conditions is expected that might otherwise accompany significant population growth. Personnel hired for this project will likely be drawn from the existing regional population, with no appreciable changes in traffic or other growth associated parameters.

The nearest Class I area to the Mont Belvieu facility is the Breton Wilderness Area, located approximately 550 kilometers from Mont Belvieu. EPA guidance states that projects of the size being proposed in this permitting action that are further than 100 kilometers from a Class I area may not affect a Class I area. Thus, further analysis of the project's impact on air quality and AQRV's in Class I areas is not necessary. Given the large distance from the Mont Belvieu facility, Lone Star does not impact a Class I area as a result of the FRAC II project.

Response to EPA questions on GHG PSD application - Lone Star, Mont Belvieu - Frac II

James Smith to: Aimee Wilson 05/08/2012 02:46 PM

Cc: "Weiler, Jeff", Deever Bradley , Pradnya Kulkarni

1 attachment

3408BR-document.pdf

Aimee, on behalf of Energy Transfer, ERM submits this response to your technical review questions regarding the GHG PSD application for Lone Star's Mont Belvieu Frac II project. We believe these responses address your questions, but please let us know otherwise.

Regards,

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Dear Aimee,

Thank you for giving Lone Star NGL, LLC (Lone Star) this chance to respond to your questions resulting from your technical review of our GHG PSD application. The following paragraphs summarize our responses to the questions that we received from you on March 29, April 3, and April 4, 2012. Please review our responses, and should you have any follow-up or additional questions, do not hesitate to call Jeff Weiler (Energy Transfer Partners) at (210) 403-7323 or James Smith (ERM) at (225) 368-2020.

1. *The permit application indicates that Lone Star will utilize "efficient heater and burner design." Please provide benchmarking data or any other technical support information to support your conclusion. EPA notes that the application does detail the type of equipment and proposed technology for energy efficiency but does not have a comparative benchmark study to indicate other similar industry operating or designed units, nor does it compare the design efficiency of the process to other similar or alike processes.*

   Lone Star has not yet purchased specific equipment for the FRAC II unit. Therefore, we cannot provide equipment specifications particular to the FRAC II process. However, in the permit application submitted by Lone Star to EPA on December 11, 2012, we proposed the following control technologies as Best Available Control Technologies (BACT) for the proposed Hot Oil Heater and Regeneration Heater:

   - Combustion air controls - limitations on excess air;
   - Fuel selection/switching;
   - Efficient heater and burner design;
   - Periodic tune-ups and maintenance for optimal thermal efficiency;
   - Heat recovery; and
   - Proper operation and good combustion practices.

   Although specific equipment have not yet been purchased, the currently proposed Hot Oil and Regen heater burners for FRAC II will be John Zink Ultra-Low NOx burners (ULNBs). In addition, a burner management system (BMS) will be in place for both heaters for optimal heater performance. Efficient heater and burner design was proposed as BACT as new burner design improves the mixing of fuel, creating a more efficient heat transfer. Because this is a new facility, new burners will be utilized. Older, improperly sized, or mechanically deteriorated burners are typically inefficient. Inoperable dampers, broken registers, or clogged nozzles will render an otherwise good burner into a poor performer. These inefficiencies result in incomplete combustion and the need for higher excess air. The potential for efficiency gains from new burners is a function of the difference between the old and new technologies. Per the example scenario provided in EPA's *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boilers (October 2010)*, a natural gas burner requiring 2 percent excess oxygen (O_2) (or 10 percent

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excess air) in the flue gas has an efficiency of about 84 percent. A less efficient burner, requiring 5 percent O_2 (or about 25 percent excess air), has about an 83 percent efficiency, a 1 percent net loss in efficiency. Further, EPA has estimated that there could be up to 6% CO_2 reduction as a result of retrofitting or replacing old burners with new burners.[1] In addition, Lone Star will utilize burner management systems on the heaters, such that intelligent flame ignition, flame intensity controls, and flue gas recirculation optimize the efficiency of the devices. Such improved combustion measures will also contribute to incremental efficiency gains and resulting CO_2 reductions.

Note that it is difficult to determine an accurate thermal efficiency for the Hot Oil Heater. Thermal efficiency relates to the amount of heat (Btu) that the burner produces to the amount of heat actually transferred to the thermal fluid (hot oil), with wasted heat mostly released out of the stack (small heat losses due to air leakage or as a result of poor insulation of the heater shell). As described in Section 5.0 of the permit application, the Hot Oil Heater for FRAC II will provide the heat to generate hot oil to be transferred in a network of piping that will circulate the oil through various areas of the FRAC II process (i.e., Amine Regeneration unit, Molecular Sieve regeneration unit, and as needed to various heat exchangers throughout the process). Because of the complexity of the hot oil system with regard to heat loss, it will be difficult to establish a single thermal efficiency for the heater.

For the FRAC II Unit, Lone Star proposes an output based BACT limit for the heaters, in lb CO_2 emitted per barrels of natural gas liquids produced (i.e., lb CO_2/bbl). We will commit to such a BACT limit, in lieu of heater-specific operating parameter limits (e.g. thermal efficiency, excess air, flue gas exhaust temperature, etc.).

2. *The application provides a five-step BACT analysis for Carbon Capture and Sequestration (CCS) and concludes that the use of this technology is economically unviable. A cost analysis with a comparison to the current projects annualized cost needs to be provided to support a determination of economic unviability.*

   The estimated annualized cost for the CCS control is $8,470,041 (see PSD application, Appendix B, Table B-3). The estimated annualized cost for the FRAC II project is $32,311,773.78 (see attached calculation).

3. *How many barrels per day, or year, will be processes by the FRAC II unit?*

   The FRAC II unit will produce approximately 100,000 barrels per day of liquid products.

---

[1] Table 1 of ***Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial,*** *and Institutional Boilers*, U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: October 2010). http://www.epa.gov/nsr/ghgdocs/iciboilers.pdf.

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4. *Plot Plan - Can I get a plot plan that identifies the FRAC II project?*

   The plot plan submitted with the PSD application shows the proposed FRAC II train. We have labeled the plot plan with the words "FRAC II" to be clear that the plot plan represents FRAC II.

5. *What are the emissions of CH_4 and N_2O from the flare and thermal oxidizer?*

   CH_4 and N_2O emissions from the Thermal Oxidizer were provided in Table A-4 of Appendix A. For better understanding, a summary table is now included at the end of Table A-4 and is copied below.

Table 1. Total GHG Emissions from Thermal Oxidizer (tpy)

	Total CO_2e Emissions (tpy)	Total CH_4 Emissions (tpy)	Total N_2O Emissions (tpy)	Total CO_2 Emissions (tpy)
Fuel Gas Combustion	5,124.76	0.10	0.01	5,119.74
Waste Gas	37,577.89	0.08	0.01	31,286.59
Total	42,702.64	0.18	0.02	36,406.32

CH_4 and N_2O emissions from the Flare result from pilot gas and MSS stream combustion. As noted in Section 1.0 (Introduction) of the PSD application, the application only addresses new and affected existing sources associated with the FRAC II project. The site Flare will support both the FRAC I and FRAC II processes; therefore, it is an existing affected source. Flare emissions were originally authorized via the FRAC I minor new source TCEQ Standard Permit in 2010, prior to the start of the GHG PSD Tailoring Rule (January 2, 2011). Flare emissions from FRAC I (previously authorized) resulted from FRAC I MSS combustion as well as pilot gas combustion. The current GHG PSD application only addresses FRAC II MSS combustion because the natural gas flowrate to the pilots remains unchanged for the FRAC II project. GHG emissions from the Flare pilots were not considered in 2010. However, for completeness, the Flare GHG emissions from pilot gas combustion are provided below:

Table 2. GHG Emissions from Flare Pilot Gas Combustion (lb/hr, tpy)
(*for informational purposes only*)

CO_2 Hourly Emissions (lb/hr)	CO_2 Annual Emissions (tpy)	CH_4 Hourly Emission Rate (lb/hr)	CH_4 Annual Emission Rate (tpy)	N_2O Hourly Emission Rate (lb/hr)	N_2O Annual Emission Rate (tpy)	CO_2e Hourly Emission Rate[2] (lb/hr)	CO_2e Annual Emission Rate (tpy)
23.845	104.443	0.0004	0.002	0.00004	0.0002	23.87	104.55

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6. *What is the EPN for fugitives?*

The FRAC II fugitives source is EPN 019-FUG.

7. *What is the DRE of the flare? Page 18 shows 99.9%, but the BACT analysis for the TO says the flare has a 98% DRE.*

The Thermal Oxidizer will have a control efficiency of 99% (used in Table A-4 for TO emission rate calculations). The Flare will also have a control efficiency of 99% (used in Table A-6 for Flare MSS emissions). We have corrected the typos in Section 5.0 (Process Description and Flow Diagram) and Section 8.0 (BACT, Table 8-2). See attached revised pages. Additionally, in Table 8-2 of the permit application (BACT summary), we originally wrote for the thermal oxidizer that, "The thermal oxidizer has a higher destruction efficiency (99%) than the flare (98%). As such, use of the flare in lieu of the thermal oxidizer is considered infeasible." Because both control devices have the same destruction efficiency, this statement has been re-worded to say "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."

8. *I'm extremely confused by the TO emissions. Table A-1 does not match Table A-4. Table A-4 is confusing in itself.*

Table A-4 has been updated with additional notes for better understanding, and the updated table is attached to this response. This updated table replaces Table A-4 in the submitted PSD application.

Essentially, emissions from the Thermal Oxidizer result from:
(a) combustion of fuel gas
(b) combustion of process waste gas

(a) combustion of fuel gas:

Emissions from <u>fuel gas combustion</u> are based upon a firing rate of 10 MMBtu/hr and emission factors from 40 CFR 98 Subpart C. Example calculations are given in Section 6.2.1 of the PSD application.

(b) combustion of process waste gas:

Emissions from <u>process waste gas combustion</u> are based upon the composition of waste process gas sent to the TO (the waste process gas stream is called "T. Oxid Blowr Suct", see Table A-4). The stream contains CO_2, which will result in direct CO_2 emissions from the TO. Additional CO_2 emissions will result from combustion of organics in the waste process gas stream. Further, the waste stream contains methane (CH_4). Using a control efficiency of 99% for the thermal oxidizer, any uncontrolled CH_4 emissions are counted towards direct CH_4 emissions from the thermal oxidizer. Finally, nitrous oxide (N_2O) emissions from the waste process gas stream are calculated based upon the heating value of the stream. Example calculations are given in Section 6.2.2 of the PSD application.

9. Will *the heaters have low-NOx stage/quenching burners?*

   Although specific equipment have not yet been purchased, the currently proposed Hot Oil and Regen heater burners for FRAC II will be John Zink Ultra-Low NOx burners (ULNBs). In addition, a burner management system (BMS) will be in place for both heaters for optimal heater performance.

10. *Are the MSS emissions for the heaters expected to be the same as or lower than the emissions from normal operations?*

    The heaters are not expected to have GHG emissions in excess of the proposed allowable emission rates during periods of maintenance, startup, or shutdown because the fuel firing rates will be below the maximum rate and proper combustion is expected to commence very quickly.

11. *Will there be oxygen analyzers for the waste gas to the TO?*

    Lone Star does not plan to use oxygen analyzers on the waste gas streams to the thermal oxidizer. In lieu of analyzers, Energy Transfer will obtain, at least once per year, an updated analysis of the Amine Unit waste gas streams, to document the CO_2 and methane content of the streams. This analysis will be considered to be representative of the gas streams for the calendar year during which it was taken, and will be used to estimate emissions from the thermal oxidizer (together with fuel gas combustion).

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Amortized Project Costs (without carbon capture and sequestration)

(April 21, 2012)

Total Capital Investment (TCI)	$317,241,758
Capital Recovery Factor (CRF) $i (1 + i)^n/((1 + i)^n - 1)$	0.10
i = interest rate = 0.08 n = equipment life = 20 years	

Amortized Installation Costs = CRF*TCI	$32,311,773.78
Total Project Annualized Cost =	$32,311,773.78

Note: Plant equipment life is expected to be 20 years due to normal plant life expectations.
CCS equipment is expected to have a life of 10 years due to extreme acidic nature of CO2.

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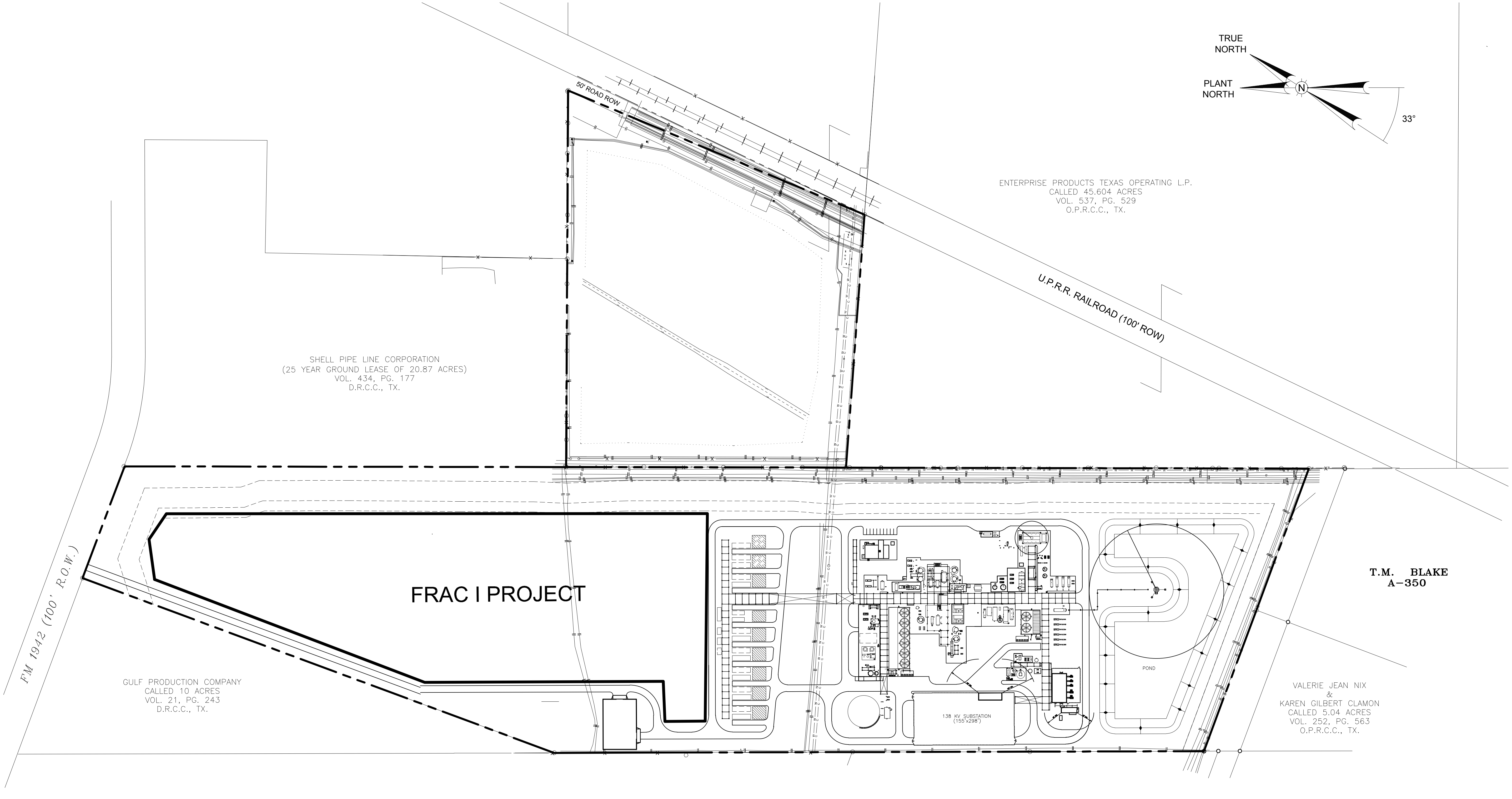

FRAC II

0 300 600
SCALE FEET

ERM-Southwest, Inc. TX PE Firm No. 2393

Environmental Resources Management

FIGURE 2
SITE PLOT PLAN
Lone Star NGL Mont Belview Gas Plant
Mont Belvieu, Texas

ERM

DESIGN: ST	DRAWN: EFC	CHKD.: ST
DATE: 11/18/2011	SCALE: AS SHOWN	REV.:

W.O.NO.: H:\DWG\K11\0140876c001.DWG , 11/18/2011 12:11:43 PM

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Table 8-2: Top-Down BACT Analysis for GHG Emissions – Revised 4-21-2012

Emission Source		STEP 1. IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES		STEP 2. ELIMINATE TECHNICALLY INFEASIBLE OPTIONS		STEP 3. RANK REMAINING CONTROL TECHNOLOGIES	STEP 4. EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS	STEP 5. SELECT BACT
Source Description	PSD Pollutant	Control Technology	Control Technology Description	RBLC Database Information	Technical Feasibility	Typical Overall Control Efficiency	Cost Effectiveness ($/ton)	
HOT OIL HEATER, MOLE SIEVE REGENRATION HEATER	**GHG**	**Combustion Air Controls - Limitations on Excess Air**	Excessive combustion air reduces the efficiency of hot oil heater burners. Oxygen monitors and intake air flow monitors can be used to optimize the fuel/air mixture and limit excess air.	Not listed in RBLC Database	**Feasible.**	1% - 3% [1]	NA – Selected as BACT	👍
		Fuel Selection/Switching	Lonestar will be firing only pipeline quality natural gas, which results in 28% less CO_2 production than fuel oils (see 40 CFR Part 98, Subpart C, Table C-1, for a comparison of the GHG emitting potential of various fuel types).	Not listed in RBLC Database	**Feasible.**	28% [2]	NA – Selected as BACT	👍
		Fuel Gas Preheating	Air preheater package consists of a compact air-to-air heat exchanger installed at grade level through which the hot stack gases from the convective section exchange heat with the incoming combustion air. Preheating the fuel stream reduces the heating load, increases thermal efficiency and, therefore, reduces emissions. However, this technology is more relevant to large boilers (>100 MMBtu/hr).	Not listed in RBLC Database	**Infeasible.** For the Hot Oil heater, Lonestar will not be preheating the natural gas because more efficient options are available. For the Regen heater, preheating the fuel gas is not feasible due to the size of the heater (< 100 MMBtu/hr) and because more efficient options are available.			
		Efficient heater and burner design	New burner design improves the mixing of fuel, creating a more efficient heat transfer. Because this is a new facility, new burners will be utilized. Lonestar will utilize burner management systems on the heaters, such that intelligent flame ignition, flame intensity controls, and flue gas recirculation optimize the efficiency of the devices.	Not listed in RBLC Database	**Feasible.**	NA	NA – Selected as BACT	👍
		Periodic tune-ups and maintenance for optimal thermal efficiency	Lonestar will tune the heaters once a year for optimal thermal efficiency.	Not listed in RBLC Database	**Feasible.**	1% - 10% [3]	NA – Selected as BACT	👍
		Heat Recovery	The hot effluent from the hot oil heater is cooled in the primary and secondary heat exchangers that heat the hot oil (heat transfer medium for the Site) to recover this energy and reduce the overall energy use in the plants. Tertiary exchangers also recover heat and contribute to overall energy efficiency. Finally, the combustion convective section is used to preheat the hot oil to the extent that the final exiting flue gas temperature is reduced to its practical limit.	Not listed in RBLC Database	**Feasible.**	NA	NA – Selected as BACT	👍

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Table 8-2: Top-Down BACT Analysis for GHG Emissions – Revised 4-21-2012

Emission Source		STEP 1. IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES		STEP 2. ELIMINATE TECHNICALLY INFEASIBLE OPTIONS		STEP 3. RANK REMAINING CONTROL TECHNOLOGIES	STEP 4. EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS	STEP 5. SELECT BACT
Source Description	**PSD Pollutant**	**Control Technology**	**Control Technology Description**	**RBLC Database Information**	**Technical Feasibility**	**Typical Overall Control Efficiency**	**Cost Effectiveness ($/ton)**	
HOT OIL HEATER, MOLE SIEVE REGENRATION HEATER	**GHG**	**Proper Operation and Good Combustion Practices**	The formation of GHGs can be controlled by proper operation and using 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. Further information on the good combustion practices that Lone Star shall implement as BACT is provided in Section 8.5.	Not listed in RBLC Database	**Feasible.**	NA	NA – Selected as BACT	👍
FLARE	**GHG**	**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. Poor combustion efficiencies can occur at very low flare rates, very high flow rates (i.e., high flare exit velocities), and when flaring gas with low heat content and excessive steam to gas mass flows. Lone Star 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. Please note that 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 add-on controls are not technically feasible. Periodic maintenance will help maintain the efficiency of the Flare. The Flare will also be operated in accordance with 40 CFR §60.18, including heating value and exit velocity requirements, as well as pilot flame monitoring. Good combustion techniques that will be implemented shall include: - Operator practices - Maintenance knowledge - Maintenance practices Further information on the Good Combustion Practices that Lonestar shall implement as GHG BACT for the Flare is provided in Section 8.5.	Not listed in RBLC Database	**Feasible.**	NA	NA – Selected as BACT	👍
FLARE		**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.	Not listed in RBLC Database	**Feasible.**	NA	NA – Selected as BACT	👍

Table 8-2: Top-Down BACT Analysis for GHG Emissions – Revised 4-21-2012

Emission Source		**STEP 1. IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES**		**STEP 2. ELIMINATE TECHNICALLY INFEASIBLE OPTIONS**		**STEP 3. RANK REMAINING CONTROL TECHNOLOGIES**	**STEP 4. EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS**	**STEP 5. SELECT BACT**
Source Description	**PSD Pollutant**	**Control Technology**	**Control Technology Description**	**RBLC Database Information**	**Technical Feasibility**	**Typical Overall Control Efficiency**	**Cost Effectiveness ($/ton)**	
FLARE - MSS	**GHG**	**Minimize Duration of Maintenance, Startup, Shutdown 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.	Not listed in RBLC Database	**Feasible.**	NA	NA – Selected as BACT	👍
		Flare Gas Recovery	Install flare gas recovery compressor system to recover flared gas to the fuel gas system.	Not listed in RBLC Database	**Infeasible.** Please note that 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.			
THERMAL OXIDIZER	**GHG**	**Use of thermal oxidizers employing heat recovery (e.g. regenerative or recuperative thermal oxidizers)**	Use of thermal oxidizers employing heat recovery (e.g. regenerative or recuperative thermal oxidizers)	Not listed in RBLC Database	**Feasible.** ETP is evaluating both recuperative and regenerative thermal oxidizers and will provide additional information when a vendor is finalized.			👍
		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	Not listed in RBLC Database	**Infeasible.** 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.			
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. Good combustion techniques that will be implemented shall include: - Operator practices - Maintenance knowledge - Maintenance practices Further information on the Good Combustion Practices that Lonestar shall implement as BACT is provided in Section 8.5.	Not listed in RBLC Database	**Feasible.**	NA	NA – Selected as BACT	👍

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Table 8-2: Top-Down BACT Analysis for GHG Emissions – Revised 4-21-2012

Emission Source		**STEP 1. IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES**		**STEP 2. ELIMINATE TECHNICALLY INFEASIBLE OPTIONS**		**STEP 3. RANK REMAINING CONTROL TECHNOLOGIES**	**STEP 4. EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS**	**STEP 5. SELECT BACT**
Source Description	**PSD Pollutant**	**Control Technology**	**Control Technology Description**	**RBLC Database Information**	**Technical Feasibility**	**Typical Overall Control Efficiency**	**Cost Effectiveness ($/ton)**	
FUGITIVE EMISSIONS	**GHG**	Implementation of a LDAR program	LDAR programs are designed to control VOC emissions and vary in stringency. LDAR is currently only required for VOC sources. Methane is not considered a VOC, so LDAR is not required for streams containing a high content of methane. Organic vapor analyzers or cameras are commonly used in LDAR programs. TCEQ's 28VHP LDAR is currently the most stringent program, which can achieve efficiencies of 97% for valves. Lone Star will implement TCEQ's 28LAER program, which is more stringent than 28VHP, on all VOC lines associated with the Project; this program will result in a collateral reduction of GHG emissions from these piping components.	Not listed in RBLC Database	**Feasible.**	NA	NA – Selected as BACT	👍
		Use of dry compressor seals	The use of dry compressor seals instead of wet seals can reduce leaks	Not listed in RBLC Database	**Feasible.**	NA	NA – Selected as BACT	👍
		Use of rod packing for reciprocating compressors	Lone Star will utilize rod packing and will conduct annual inspections of the packing materials to determine when the packing needs replacing or any of the components need servicing.	Not listed in RBLC Database	**Feasible.**	NA	NA – Selected as BACT	👍
FUGITIVE EMISSIONS	**GHG**	Use of low-bleed gas-driven pneumatic controllers or compressed air-driven pneumatic Controllers	Low-bleed gas-driven pneumatic controllers emit less gas (that contains GHG) than standard gas-driven controllers, and compressed air-driven pneumatic controllers do not emit GHG.	Not listed in RBLC Database	**Feasible.**	NA	NA – Selected as BACT	👍
PLANT-WIDE	**GHG**	**Carbon Capture and Sequestration**	**Carbon capture** entails the separation of CO_2 from the flue gas of a combustion source after combustion has been completed. Several systems are commercially available for separating CO_2 from flue gas, the most common of which are amine-based absorber systems. Separating CO_2 from the flue gas must be paired with some form of storage, or sequestration, in order for the technology to provide any reduction in CO_2 emissions. In fact, CO_2 separation without storage actually results in an increase in total CO_2 generation, since the separation system has an energy demand as well, in the form of a reboiler for regenerating amine solution rich in CO_2, and electrical needs for system equipment.	Not listed in RBLC Database	**Infeasible.** The use of CCS is not technically or environmentally feasible for the Site. The goal of CO_2 capture is to concentrate the CO_2 stream from an emitting source for transport and injection at a storage site. CCS requires a highly concentrated, pure CO_2 stream for practical and economic reasons. Some of the equipment part of the proposed project does not operate on a continuous basis. For e.g., 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 add-on controls are not technically feasible. Therefore, CCS is considered technically infeasible for the	80% [4]	As shown in Appendix B, Tables B-1 through B-3, the cost effectiveness of CCS is estimated to be $350.19 per ton of CO_2 removed. Due to this high cost effectiveness, CCS is also economically infeasible.	

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Table 8-2: Top-Down BACT Analysis for GHG Emissions – Revised 4-21-2012

Emission Source		STEP 1. IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES		STEP 2. ELIMINATE TECHNICALLY INFEASIBLE OPTIONS		STEP 3. RANK REMAINING CONTROL TECHNOLOGIES	STEP 4. EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS	STEP 5. SELECT BACT
Source Description	**PSD Pollutant**	**Control Technology**	**Control Technology Description**	**RBLC Database Information**	**Technical Feasibility**	**Typical Overall Control Efficiency**	**Cost Effectiveness ($/ton)**	
					flare. For the continuously operated equipment at the site (heaters, thermal oxidizer), extracting CO_2 from exhaust gases requires equipment to capture the flue gas exhaust and to separate and pressurize the CO_2 for transportation. The stack vent streams will be low pressure, high volume streams at a very high temperature, with low CO_2 content and will contain miscellaneous pollutants, such as PM that can contaminate the separation process. Additionally, piping would need to be stainless steel due to the corrosive nature of CO_2.			
PLANT-WIDE	**GHG**	**Carbon Capture and Sequestration (continued)**	**Dedicated sequestration** involves the injection of CO_2 into an on-site or nearby geological formation, such as an active oil reservoir (enhanced oil recovery), a brine aquifer, an unmined coal seam, basalt rock formation, or organic shale bed. Geologic sequestration is being studied in several locations and geologies, with varying results and predictions. For geologic sequestration to be a feasible technology, a promising geological formation must be located at, or very near, the facility location. **Off-site sequestration** involves utilization of a 3rd-party CO_2 pipeline system to transport CO_2 to more distant geologic formations that may be more conducive to sequestration than sites in the immediate area. Building such a pipeline for dedicated use by a single facility is almost certain to make any project economically infeasible, from both an absolute and BACT-review perspective. However, such an option may be effective if adequate storage capacity exists downstream and reasonable transportation prices can be arranged with the pipeline operator.		The CO_2 separation from the exhaust /waste gas streams requires several steps: filtration, cooling, compression, CO_2 removal using amine units, and recompression. Filtration would require the removal of PM from the streams without creating too much back pressure on the upstream system (i.e., the facility's combustion processes). Next cooling: the installation of additional cryogenic units or other cooling mechanisms (e.g. complex heat exchangers) would be required to reduce the temperature of the streams from over 800 F to less than 100 F prior to separation, compression, and transmission. The cryogenic units would require propane compression. Inlet compression would be needed to increase the pressure from atmospheric to the minimum of 700 pounds per square inch (psi) required for efficient CO_2 separation. The installation of a dedicated amine unit to capture the CO_2 from the exhaust/waste streams and a natural gas-fired heater to separate CO_2 from the rich amine would be required. Finally, the separated CO_2 stream would require large compression equipment, capable of handling acidic gases (stainless steel compressor) with high energy consumption/cost, to pressurize the CO_2 from near atmospheric pressure up to the receiving pipeline pressure to transfer offsite. Moreover, because the electricity required to run all of the above			

Table 8-2: Top-Down BACT Analysis for GHG Emissions – Revised 4-21-2012

Emission Source		STEP 1. IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES		STEP 2. ELIMINATE TECHNICALLY INFEASIBLE OPTIONS		STEP 3. RANK REMAINING CONTROL TECHNOLOGIES	STEP 4. EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS	STEP 5. SELECT BACT
Source Description	PSD Pollutant	Control Technology	Control Technology Description	RBLC Database Information	Technical Feasibility	Typical Overall Control Efficiency	Cost Effectiveness ($/ton)	
					mentioned equipment additional natural gas-fired generators would be required. Therefore, the fuel consumption and resultant combustion-related GHG emissions would be even greater than emissions from the proposed project.			
PLANT-WIDE	GHG	**Carbon Capture and Sequestration (continued)**		Not listed in RBLC Database	To process this stream for CCS, the Site would need to have an additional 100 MMSCFD amine unit, cryogenic unit, and associated equipment (i.e., heaters, CO_2 surge tanks, compressor engines, and piping control system) greater than the size of the proposed plant. Engine horsepower needed to compress the exhaust/waste gas streams for CO_2 separator would be more than 28,000 hp [equivalent to 6 Caterpillar 3616 engines @ 4735 hp each]. Notably 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. This compression configuration would have to be repeated to get the CO_2 from the amine regenerator into a CO_2 pipeline. Therefore, this type of control strategy would generate over 250,000 tons of CO_2 which is nearly equivalent to the proposed project. Therefore, Lone Star believes that CCS is not BACT due to its negative environmental and energy impacts. Further, although current technologies could be used to capture CO_2 from new and existing plants, they are not ready for widespread implementation. Based upon on the issues identified above, Lone Star does not consider CCS to be a technically, economically, or commercially viable GHG control option for the Site.			
PLANT-WIDE	GHG	**Use of electric-driven Engines**	The refrigeration compressors will be electric-driven, resulting in no GHG emissions from these sources.	Not listed in RBLC Database	**Feasible.**	100% [5]	NA – Selected as BACT	👍

[1] *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry*, issued by EPA in October 2010. Section 3.0, Summary of GHG Reduction Measures, Table 1: Summary of GHG Reduction Measures for the Petroleum Refinery Industry.

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[2] 40 CFR Part 98 Subpart C, Table C-1.

[3] *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industr*y, issued by EPA in October 2010. Section 5.1.1.5 Improved Maintenance.

[4] *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industr*y, issued by EPA in October 2010. Section 5.1.4, Carbon Capture.

[5] Based upon only using electricity so no combusted related GHG emissions.

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TABLE A-4 (Revised 4-21-2012)

Thermal Oxidizer Emission Rate Calculations

Section 6.2 of the permit application decribes thermal oxidizer emissions in detail. Briefly, emissions from the thermal oxidizer will result from combustion of fuel gas and combustion of waste gas from the process. Therefore, emissions from each contributing gas are calculated below.

Emissions from Fuel Gas Combustion:

Emissions from fuel gas combustion are based on average firing rate of 10 MMBtu/hr and emission factors in Tables C-1 and C-2 of 40 CFR 98, Subpart C for natural gas and design firing rate of the thermal oxidizer.

Process Data[1]:

Firing rate	10	MMBtu/hr
Fuel Heating Value =	1,020	Btu/scf

Table A-4a. Global Warming Potentials & Emission Factors:

Pollutant	Global Warming Potential[2]	Emission Factor[3] (kg/MMBtu)
CO_2	1	53.02
CH_4	21	1.0E-03
N_2O	310	1.0E-04

Table A-4b. Maximum Hourly Emission Rate (lbs/hr)

Emission Point	CO_2 (lb/hr)	CH_4 (lb/hr)	N_2O (lb/hr)
012-THERMO	1168.890	0.022	0.0022

Table A-4c. Annual Average Emission Rate (tpy)

Emission Point	CO_2 (tpy)	CH_4 (tpy)	N_2O (tpy)	CO_2e (tpy)
012-THERMO	5119.74	0.097	0.010	5124.757

Notes:

1) Firing rate and DRE were provided by vendor.

2) Default global warming potentials from 40 CFR 98, Subpart A, Table A-1.

3) Default emission factors from 40 CFR 98, Subpart C, Tables C-1 and C-2, for natural gas.

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TABLE A-4 (Revised 4-21-2012)

Thermal Oxidizer Emission Rate Calculations

Emissions from Waste Gas Combustion:

Emissions from waste gas combustion can be divided into the following -

1) Direct CO_2 emissions from the waste gas, based on vendor provided data on thermal oxidizer inlet stream (i.e. T. Oxid Blowr Suct stream)
2) CO_2 generated by combustion of the waste gas, calculated using 40 CFR 98.233 Eq. W-21
3) Direct CH_4 emissions that are uncontrolled by the thermal oxidizer based on a destruction efficiency of 99%
4) N_2O emissions generated by combustion of waste gas, calculated using 40 CFR 98 Subpart W, Eq. W-40.

The table below provided composition of of the thermal oxidizer inlet process stream called T. Oxid Blowr Suct.

Table A-4d. Process Stream Composition Data to Thermal Oxidizer

Streams	Component	Vapor Phase Composition[2]	Uncontrolled Total VOC Emissions to TO[3]	Flow Rate[2]	Stream Lower Heating Value[2]	Gas Firing Rate[4]	
		lb/hr	lb/hr	mmScf/hr	Btu/scf	MMBtu/hr	MMBtu/yr
T. Oxid Blowr Suct[1]	Carbon Dioxide	7,143.06					
	Methane	1.80	234.93	0.092	102.12	9.36	82005.36
	Ethane	211.60					
	Propane	114.46					
	i-Butane	31.45					
	n-Butane	3.61					
	i-Pentane	16.35					
	n-Pentane	13.36					
	n-Hexane	11.16					
	n-Heptane	0.26					
	n-Octane	0.09					
	n-Nonane	0.00					
	Propene	44.19					
	Nitrogen	1,458.20					

Notes:

1) Following streams are combined at the vent header to form the T. Oxid Blowr Suct stream: DEA Regen Acid Gas, Rich Amine Drum Vent, and Compressor Seals. Therefore the composition of the T. Oxid Blowr Suct stream is used to determine GHG emissions from the thermal oxidizer.

Data on these streams are provided below for completeness in Table A-4e, however, only the T. Oxid Blowr Suct stream data are used in emission calculations.

2) Vendor provided data
3) Calculated by summing all VOC components of the stream
4) Calculated from stream LHV and flow rate

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TABLE A-4 (Revised 4-21-2012)

Thermal Oxidizer Emission Rate Calculations

Table A-4e. Composition of individual process streams contributing to the Thermal Oxidizer inlet stream (see Note 1 above)

Streams	Component	Vapor Phase Composition[2]	Streams	Component	Vapor Phase Composition[2]	Streams	Component	Vapor Phase Composition[2]
		lb/hr			lb/hr			lb/hr
Compressor Seals	Carbon Dioxide	0.00	DEA Regen Acid Gas	Carbon Dioxide	7,142.39	Rich Amine Drum Vents	Carbon Dioxide	0.67
	Methane	0.00		Methane	0.18		Methane	1.62
	Ethane	0.00		Ethane	25.80		Ethane	185.80
	Propane	6.97		Propane	8.81		Propane	82.50
	i-Butane	9.19		i-Butane	0.00		i-Butane	0.92
	n-Butane	0.00		n-Butane	0.00		n-Butane	1.29
	i-Pentane	0.00		i-Pentane	0.00		i-Pentane	0.62
	n-Pentane	0.00		n-Pentane	0.00		n-Pentane	0.47
	n-Hexane	0.00		n-Hexane	0.09		n-Hexane	2.08
	n-Heptane	0.00		n-Heptane	0.00		n-Heptane	0.26
	n-Octane	0.00		n-Octane	0.00		n-Octane	0.09
	n-Nonane	0.00		n-Nonane	0.00		n-Nonane	0.00
	Propene	13.31		Propene	0.00		Propene	0.00
	Nitrogen	425.17		Nitrogen	0.00		Nitrogen	0.00

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TABLE A-4 (Revised 4-21-2012)

Thermal Oxidizer Emission Rate Calculations

The Table below provides emissions from waste process gas combustion based on composition of the Thermal Oxidizer inlet stream called T. Oxid Blowr Suct (provided in Table A-4d).

Table A-4f. Emissions from Combustion of Waste Gas

Emissions from Waste Gas	Direct CO_2 Emissions from Waste Gas[1]		CO_2 from Combustion of Waste Gas[2] (see Table A-4g below for detailed calculations)	Direct CH_4 Emissions from Waste Gas[3]		N_2O from Combustion of Waste Gas[4]
	lb/hr	tpy	tpy	lb/hr	tpy	tpy
	7,143.06	31,286.59	6287.10	0.02	0.08	0.0082

Notes:
1) Based on vendor provided data of the T. Oxide Blowr Suct stream. Assumed that TO does not control CO_2 emissions.
2) Calculated using Eq. W-21 and W-36 of 40 CFR 98, Subpart W. Detailed calculations of carbon flow are provided below in Table A-4g.
3) Based on vendor provided data of the T. Oxide Blowr Suct stream and 99% destruction efficiency of the TO. Annual emissions are estimated assuming 8760 hours/year.
4) Calculated using Eq. W-40 of 40 CFR 98, Subpart W.

Table A-4g. Determination of CO_2 emissions from waste process gas combustion (see Note 2 above)

Compound	No. of Carbons	Mol Wt.	Flow Rate[a]	Concentration[b]	Carbon Weighted Flow[c]	CO_2 Emissions from Combustion[c]	
			lb/hr	%	scf/yr	scf/yr	tpy
Methane	1	16.043	1.80	0.02	160,600	157,388	9.31
Ethane	2	30.070	211.60	2.27	36,456,200	35,727,076	2,114.33
Propane	3	44.097	114.46	1.23	29,630,700	29,038,086	1,718.47
i-Butane	4	58.123	31.45	0.34	10,920,800	10,702,384	633.37
n-Butane	4	58.123	3.61	0.04	1,284,800	1,259,104	74.51
i-Pentane	5	72.150	16.35	0.18	7,227,000	7,082,460	419.14
n-Pentane	5	72.150	13.36	0.14	5,621,000	5,508,580	326.00
n-Hexane	6	86.172	11.16	0.12	5,781,600	5,665,968	335.31
n-Heptane	7	100.198	0.26	0	0	0	0.00
n-Octane	8	114.224	0.09	0	0	0	0.00
n-Nonane	9	128.200	0.00	0	0	0	0.00
Propene	3	42.080	44.19	0.47	11,322,300	11,095,854	656.65
Total					108,405,000	106,236,900	6287.10

Notes:
a) Vendor provided data
b) Based on mole fraction and number of carbon atoms in each compound.
c) Eq. W-21 of 40 CFR 98, Subpart W. Assumed default value of η of 0.98. Conversion from scf/yr to tpy is based on Eq. W-36 of 40 CFR 98, Subpart W.

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TABLE A-4 (Revised 4-21-2012)

Thermal Oxidizer Emission Rate Calculations

Table A-4h. Total GHG Emissions from Thermal Oxidizer (tpy)				
	Total CH_4 Emissions (tpy)	Total N_2O Emissions (tpy)	Total CO_2 Emissions (tpy)	Total CO_2e Emissions (tpy)
Fuel Gas Combustion	0.10	0.01	5,119.74	5,124.76
Waste Gas Combustion	0.08	0.01	37,573.69	37,577.89
Total	0.18	0.02	42,693.42	42,702.64