ENERGY TRANSFER

800 E. Sonterra Blvd., Suite 400
San Antonio, Texas 78258-3941
210-403-7300
210-403-7500 (Fax)

RECEIVED

DEC 1 2011

Air/Toxics & Inspection
Coordination Branch
6EN-A

December 7, 2011

CERTIFIED MAIL

US EPA
Region 6
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202

AIR PERMITS SECTION
6PD-R
11 DEC 14 PM 4: 19
RECEIVED

Re: Greenhouse Gas PSD Permit Application
        Energy Transfer Partners, L.P. dba Lone Star NGL, LLC
        Mont Belvieu Gas Plant, Chambers County, Texas

Enclosed please find the Greenhouse Gas (GHG) Prevention of Significant Deterioration
(PSD) permit application for the above-referenced site. This package is presented to obtain
authorization for the construction of a natural gas liquids fractionation plant in Mont Belvieu,
Chambers County, Texas.

This pack contains the emission calculations, regulatory applicability review, and Best
Available Control Technology analysis along with supporting information in compliance with
40 CFR Part 98 and 52 of the Federal regulations.

If you have questions, please contact me at 210-403-7323 or Clint Cowan of Energy Transfer
at 210-403-7470.

Sincerely,

Jeff L. Weiler
Environmental Manager

Attachment

Cc: ERM, 15810 Park Ten Place, Suite 300, Houston, Texas 77084

Prevention of Significant Deterioration (PSD) Air Quality Permit Application for Greenhouse Gas Emissions

Lone Star NGL Mont Belvieu Gas Plant
Energy Transfer Partners, L.P.

December 2, 2011

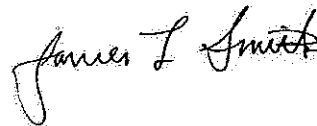www.erm.com

Energy Transfer Partners, L.P.

Prevention of Significant Deterioration (PSD) Air Quality Permit Application for Greenhouse Gas Emissions
Mont Belvieu, Texas

December 2, 2011

Project No. 0140876
Lone Star NGL Mont Belvieu Gas Plant
Energy Transfer Partners, L.P.

Donald D. Bradley III, P.E.

Partner-in-Charge

James L. Smith

Project Manager

Environmental Resources Management
15810 Park Ten Place, Suite 300
Houston, Texas 77084-5140
T: 281-600-1000
F: 281-600-100

Texas Registered Engineering Firm F-2393

TABLE OF CONTENTS

1.0   *INTRODUCTION*

Energy Transfer Partners, L.P. (ETP), dba Lone Star NGL Mont Belvieu Gas
Plant (Lone Star), submits this Prevention of Significant Deterioration (PSD)
application for greenhouse gases (GHGs) to obtain authorization to construct a
second fractionation train (FRAC II) at its existing natural gas processing plant
located in Mont Belvieu, Chambers County, Texas.

Lone Star purchased the existing Mont Belvieu gas processing plant when it
bought LDH Energy Asset Holdings LLC on May 2, 2011, which included the
Mont Belvieu site owned by LDH Energy Mont Belvieu GP LLC[1]. Criteria
pollutant emissions from the existing plant were previously authorized via a
Standard Permit for Oil and Gas Facilities (30 TAC §116.620), issued on
December 13, 2010. Construction on the proposed Mont Belvieu gas plant
commenced prior to July 1, 2011, with expected startup in the third quarter of
2012. Like the previous representation, the proposed plant will be located near
Lone Star's (formerly LDH Energy's) existing North Terminal transfer and
storage facility in Mont Belvieu. The gas plant, however, is independent of the
existing North Terminal. The primary Standard Industrial Classification (SIC)
code for the proposed gas plant (1321, Natural Gas Liquids) is different than that
of the North Terminal (4613, Petroleum Pipelines, Refined). Because of the
independence of the two plants, LDH Energy requested, and received, a new
Regulated Entity Number (RN) from the Texas Commission on Environmental
Quality (TCEQ): RN106018260. Lone Star will retain this RN for the site that
will include FRAC II.

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; therefore FRAC I is not subject to the PSD Tailoring Rule.

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 because the project will have a net increase of GHG emissions above
the modification applicability threshold of 75,000 tpy CO_2e. Therefore, the
proposed FRAC II project triggers federal PSD review for GHG emissions.

In December 2010, EPA finalized a rule that designates EPA as the permitting
authority for GHG emitting sources in Texas by declaring a partial disapproval of
the Texas State Implementation Plan (SIP). This rule is in effect until the EPA
approves a SIP that allows Texas to regulate GHG. Further, EPA stated in its
white paper entitled, "Issuing Permits for Sources with Dual PSD Permitting
Authorities," dated April 19, 2011, "[i]n the case of a source or project that has

---

[1] Texas Commission on Environmental Quality Customer No. CN603194101

both GHGs and non-GHGs that are subject to PSD . . . the State will issue the non-GHG portion of the permit and EPA will issue the GHG portion."[2] At this time, the EPA is the designated permitting authority for all GHG PSD permits in Texas. Accordingly, Lone Star is submitting this PSD permit application to the EPA to address the estimated increase in GHG emissions associated with the second fractionation train. Note that this application only addresses new and affected (i.e., existing sources that will see an emissions increase) emission sources associated with the installation of the second fractionation train.

Lone Star will submit to TCEQ under separate cover a Standard Permit for Oil and Gas Facilities application for non-GHG pollutant increases associated with the FRAC II modification. A copy of this permit application will be provided to EPA upon submission.

The remainder of this application is structured as follows:

- The TCEQ Form PI-1 are presented in Section 2.0;

- An area map is presented in Section 3.0 and a preliminary plot plan showing proposed emission sources is included in Section 4.0;

- A process description and simplified process flow diagram are presented in Section 5.0;

- GHG emission rate estimation methodologies are described in Section 6.0;

- A regulatory applicability analysis for GHGs is presented in Section 7.0; and

- A summary of the Best Available Control Technology (BACT) analysis performed in accordance with 40 CFR §52.21(j) for GHGs is presented in Section 8.0.

This application also contains the following appendices:

- Detailed emission rate calculations, with a corresponding summary table, are located in Appendix A;

- The supporting documentation for the BACT analysis is presented in Appendix B;

- Appendix C contains the TCEQ equipment forms and tables; and

A standard permit application to be submitted to TCEQ is being prepared and will be provided to EPA upon submission.

---

[2] See *http://www.epa.gov/nsr/ghgqa.html*

2.0   *COMPLETED PI-1*

This Section contains a completed Form PI-1 General Application for Air
Preconstruction Permit and Amendment.

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

Important Note: The agency **requires** that a Core Data Form be submitted on all incoming applications unless a Regulated Entity and Customer Reference Number have been issued *and* no core data information has changed. For more information regarding the Core Data Form, call (512) 239-5175 or go to www.tceq.texas.gov/permitting/central_registry/guidance.html.

I. Applicant Information		
A. Company or Other Legal Name: **Energy Transfer Partners, LP dba Lone Star NGL Mont Belvieu Gas Plant**		
Texas Secretary of State Charter/Registration Number (*if applicable*):		
B. Company Official Contact Name: **Clint Cowan**		
Title: **Senior Direcotr of Environmental**		
Mailing Address: **800 E. Sonterra Blvd., Ste. 400**		
City: **San Antonio**	State: **Texas**	ZIP Code: **78258**
Telephone No.: **(210) 403-7470**	Fax No.: **(210) 403-7670**	E-mail Address: clint.cowan@energytransfer.com
C. Technical Contact Name: **Jeff Weiler**		
Title: **Environmental Manager**		
Company Name: **Energy Transfer Partners, LP dba Lone Star NGL Mont Belvieu Gas Plant**		
Mailing Address: **800 E. Sonterra Blvd., Suite 400**		
City: **San Antonio**	State: **Texas**	ZIP Code: **78258**
Telephone No.: **(210) 403-7323**	Fax No.: **(210) 403-7523**	E-mail Address: Jeff.Weiler@energytransfer.com
D. Site Name: **Lone Star NGL Mont Belvieu Gas Plant**		
E. Area Name/Type of Facility: **Natural Gas Processing Plant** ☒ Permanent ☐ Portable		
F. Principal Company Product or Business: **Constituent Gas Products**		
Principal Standard Industrial Classification Code (SIC): **1321**		
Principal North American Industry Classification System (NAICS): **211112**		
G. Projected Start of Construction Date: **3Q 2012**		
Projected Start of Operation Date: **1Q 2013**		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: **10030 A. FM 1942**		
City/Town: **Mont Belvieu**	County: **Chambers**	ZIP Code: **77580**
Latitude (nearest second): **29° 51' 0"**	Longitude (nearest second): **-94° 54' 37"**	

TCEQ – 10252 (Revised 10/11) PI-1 Form
This form is for use by facilities subject to air quality permit requirements and
may be revised periodically. (APDG 5171v16)   Page _____ of _____

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

I.	Applicant Information (continued)	
I.	Account Identification Number (leave blank if new site or facility): **RN106018260**	
J.	Core Data Form.	
Is the Core Data Form (Form 10400) attached? If *No*, provide customer reference number and regulated entity number (complete K and L).		☐ YES ☒ NO
K.	Customer Reference Number (CN):	
L.	Regulated Entity Number (RN):	

II.	General Information	
A.	Is confidential information submitted with this application? If *Yes*, mark each **confidential** page **confidential** in large red letters at the bottom of each page.	☐ YES ☒ NO
B.	Is this application in response to an investigation or enforcement action? If *Yes*, attach a copy of any correspondence from the agency.	☐ YES ☒ NO
C.	Number of New Jobs: 5 - 10	
D.	Provide the name of the State Senator and State Representative and district numbers for this facility site:	
Senator: **Tommy Williams**		District No.: **4**
Representative: **John C. Otto**		District No.: **18**

III.	Type of Permit Action Requested
A.	Mark the appropriate box indicating what type of action is requested.
Initial ☒   Amendment ☐   Revision (30 TAC 116.116(e)) ☐   Change of Location ☐   Relocation ☐
B.	Permit Number (if existing): N/A
C.	Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)*
Construction ☒   Flexible ☐   Multiple Plant ☐   Nonattainment ☐   Prevention of Significant Deterioration ☒
Hazardous Air Pollutant Major Source ☐   Plant-Wide Applicability Limit ☐
Other:____GHG PSD____
D.	Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c). ☐ YES ☒ NO

TCEQ – 10252 (Revised 10/11) PI-1 Form
This form is for use by facilities subject to air quality permit requirements and
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III. Type of Permit Action Requested (continued)		
E.	Is this application for a change of location of previously permitted facilities? If Yes, complete III.E.1 - III.E.4.	☐ YES ☒ NO
1.	Current Location of Facility (If no street address, provide clear driving directions to the site in writing.):	

Street Address:

City:	County:	ZIP Code:

2. Proposed Location of Facility (If no street address, provide clear driving directions to the site in writing.):

Street Address:

City:	County:	ZIP Code:

3.	Will the proposed facility, site, and plot plan meet all current technical requirements of the permit special conditions? If *No*, attach detailed information.	☐ YES ☐ NO
4.	Is the site where the facility is moving considered a major source of criteria pollutants or HAPs?	☐ YES ☐ NO
F.	Consolidation into this Permit: List any standard permits, exemptions or permits by rule to be consolidated into this permit including those for planned maintenance, startup, and shutdown.	

List: **N/A**

G.	Are you permitting planned maintenance, startup, and shutdown emissions? If *Yes*, attach information on any changes to emissions under this application as specified in VII and VIII.	☒ YES ☐ NO
H.	Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability)	

Is this facility located at a site required to obtain a federal operating permit? If *Yes*, list all associated permit number(s), attach pages as needed).	☒ YES ☐ NO ☐ To be determined

Associated Permit No (s.):

1. Identify the requirements of 30 TAC Chapter 122 that will be triggered if this application is approved.

FOP Significant Revision ☐ FOP Minor ☐   Application for an FOP Revision ☐   To Be Determined ☒

Operational Flexibility/Off-Permit Notification ☐   Streamlined Revision for GOP ☐ None ☐

TCEQ – 10252 (Revised 10/11) PI-1 Form
This form is for use by facilities subject to air quality permit requirements and
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III. Type of Permit Action Requested (continued)	
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*	

2.	Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. (check all that apply)
GOP Issued ☐	GOP application/revision application submitted or under APD review ☐
SOP Issued ☐	SOP application/revision application submitted or under APD review ☐

IV. Public Notice Applicability	
A. Is this a new permit application or a change of location application?	☐ YES ☐ NO
B. Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2.	☐ YES ☐ NO
C. Is this an application for a major modification of a PSD, nonattainment, FCAA 112(g) permit, or exceedance of a PAL permit?	☐ YES ☐ NO
D. Is this application for a PSD or major modification of a PSD located within 100 kilometers of an affected state?	☐ YES ☐ NO
If *Yes*, list the affected state(s).	
E. Is this a state permit amendment application? If Yes, complete IV.E.1. – IV.E.3.	
1. Is there any change in character of emissions in this application?	☐ YES ☐ NO
2. Is there a new air contaminant in this application?	☐ YES ☐ NO
3. Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?	☐ YES ☐ NO
F. List the total annual emission increases associated with the application (*list all that apply and attach additional sheets as needed*):	
Volatile Organic Compounds (VOC):	
Sulfur Dioxide (SO_2):	
Carbon Monoxide (CO):	
Nitrogen Oxides (NO_x):	
Particulate Matter (PM):	
PM 10 microns or less (PM_{10}):	
PM 2.5 microns or less ($PM_{2.5}$):	
Lead (Pb): 0.0 tpy	
Hazardous Air Pollutants (HAPs):	
Other speciated air contaminants **not** listed above:	

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Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

V. Public Notice Information (complete if applicable)		
A. Public Notice Contact Name:		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
B. Name of the Public Place:		
Physical Address (No P.O. Boxes):		
City:	County:	ZIP Code:

The public place has granted authorization to place the application for public viewing and copying.	☐ YES ☐ NO
The public place has internet access available for the public.	☐ YES ☐ NO

C. Concrete Batch Plants, PSD, and Nonattainment Permits		
1. County Judge Information (For Concrete Batch Plants and PSD and/or Nonattainment Permits) for this facility site.		
The Honorable:		
Mailing Address:		
City:	State:	ZIP Code:

2. Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? *(For Concrete Batch Plants)*	☐ YES ☐ NO

Presiding Officers Name(s):		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
3. Provide the name, mailing address of the chief executives of the city and county, Federal Land Manager, or Indian Governing Body for the location where the facility is or will be located.		
Chief Executive:		
Mailing Address:		
City:	State:	ZIP Code:
Name of the Federal Land Manager:		
Title:		
Mailing Address:		
City:	State:	ZIP Code:

TCEQ – 10252 (Revised 10/11) PI-1 Form
This form is for use by facilities subject to air quality permit requirements and
may be revised periodically. (APDG 5171v16)   Page ____ of ____

V. Public Notice Information (complete if applicable) (continued)		
3. Provide the name, mailing address of the chief executives of the city and county, State, Federal Land Manager, or Indian Governing Body for the location where the facility is or will be located. *(continued)*		

Name of the Indian Governing Body:		
Title:		
Mailing Address:		
City:	State:	ZIP Code:

D. Bilingual Notice	
Is a bilingual program **required** by the Texas Education Code in the School District?	☐ YES ☐ NO
Are the children who attend either the elementary school or the middle school closest to your facility eligible to be enrolled in a bilingual program provided by the district?	☐ YES ☐ NO
If *Yes*, list which languages are required by the bilingual program?	

VI. Small Business Classification (Required)	
A. Does this company (including parent companies and subsidiary companies) have fewer than 100 employees or less than $6 million in annual gross receipts?	☐ YES ☒ NO
B. Is the site a major stationary source for federal air quality permitting?	☒ YES ☐ NO
C. Are the site emissions of any regulated air pollutant greater than or equal to 50 tpy?	☒ YES ☐ NO
D. Are the site emissions of all regulated air pollutants combined less than 75 tpy?	☐ YES ☒ NO

VII. Technical Information
A. The following information must be submitted with your Form PI-1 (this is just a checklist to make sure you have included everything)
1. Current Area Map ☒
2. Plot Plan ☒
3. Existing Authorizations ☐
4. Process Flow Diagram ☒
5. Process Description ☒
6. Maximum Emissions Data and Calculations ☒
7. Air Permit Application Tables ☒
a. Table 1(a) (Form 10153) entitled, Emission Point Summary ☒
b. Table 2 (Form 10155) entitled, Material Balance ☐
c. Other equipment, process or control device tables ☐

TCEQ – 10252 (Revised 10/11) PI-1 Form
This form is for use by facilities subject to air quality permit requirements and
may be revised periodically. (APDG 5171v16)   Page _____ of _____

VII. Technical Information

B.	Are any schools located within 3,000 feet of this facility?	☐ YES ☒ NO

C. Maximum Operating Schedule:

Hours: 8,760	Day(s): 365	Week(s): 52	Year(s): 8,760 hrs/yr

Seasonal Operation? If Yes, please describe in the space provide below.	☐ YES ☒ NO

D.	Have the planned MSS emissions been previously submitted as part of an emissions inventory?	☐ YES ☒ NO

Provide a list of each planned MSS facility or related activity and indicate which years the MSS activities have been included in the emissions inventories. Attach pages as needed.

E.	Does this application involve any air contaminants for which a *disaster review* is required?	☐ YES ☒ NO
F.	Does this application include a pollutant of concern on the *Air Pollutant Watch List (APWL)*?	☐ YES ☒ NO

VIII. State Regulatory Requirements
Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment. *The application must contain detailed attachments addressing applicability or non-applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.*

A.	Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ?	☒ YES ☐ NO
B.	Will emissions of significant air contaminants from the facility be measured?	☒ YES ☐ NO
C.	Is the Best Available Control Technology (BACT) demonstration attached?	☒ YES ☐ NO
D.	Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods?	☒ YES ☐ NO

IX. Federal Regulatory Requirements
Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment. *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*

A.	Does Title 40 Code of Federal Regulations Part 60, (40 CFR Part 60) New Source Performance Standard (NSPS) apply to a facility in this application?	☒ YES ☐ NO
B.	Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?	☐ YES ☒ NO
C.	Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?	☐ YES ☒ NO

TCEQ – 10252 (Revised 10/11) PI-1 Form
This form is for use by facilities subject to air quality permit requirements and
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Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

IX. Federal Regulatory Requirements Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*	
D. Do nonattainment permitting requirements apply to this application?	☐ YES ☒ NO
E. Do prevention of significant deterioration permitting requirements apply to this application?	☒ YES ☐ NO
F. Do Hazardous Air Pollutant Major Source [FCAA 112(g)] requirements apply to this application?	☐ YES ☒ NO
G. Is a Plant-wide Applicability Limit permit being requested?	☐ YES ☒ NO
X. Professional Engineer (P.E.) Seal	
Is the estimated capital cost of the project greater than $2 million dollars?	☒ YES ☐ NO
If *Yes*, submit the application under the seal of a Texas licensed P.E.	
XI. Permit Fee Information	
Check, Money Order, Transaction Number ,ePay Voucher Number:	Fee Amount: $
Company name on check:	Paid online?: ☐ YES ☐ NO
Is a copy of the check or money order attached to the original submittal of this application?	☐ YES ☐ NO ☐ N/A
Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?	☐ YES ☐ NO ☐ N/A

TCEQ – 10252 (Revised 10/11) PI-1 Form
This form is for use by facilities subject to air quality permit requirements and
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TCEQ

XII. Delinquent Fees and Penalties
This form **will not be processed** until all delinquent fees and/or penalties owed to the TCEQ or the Office of the Attorney General on behalf of the TCEQ is paid in accordance with the Delinquent Fee and Penalty Protocol. For more information regarding Delinquent Fees and Penalties, go to the TCEQ Web site at: www.tceq.texas.gov/agency/delin/index.html.

XIII. Signature
The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Water Code (TWC), Chapter 7, Texas Clean Air Act (TCAA), as amended, or any of the air quality rules and regulations of the Texas Commission on Environmental Quality or any local governmental ordinance or resolution enacted pursuant to the TCAA I further state that I understand my signature indicates that this application meets all applicable nonattainment, prevention of significant deterioration, or major source of hazardous air pollutant permitting requirements. The signature further signifies awareness that intentionally or knowingly making or causing to be made false material statements or representations in the application is a criminal offense subject to criminal penalties.

Name: _____

Signature: _____ *Original Signature Required* _____

Date: __ 12/6/11 _____

TCEQ – 10252 (Revised 10/11) PI-1 Form
This form is for use by facilities subject to air quality permit requirements and
may be revised periodically. (APDG 5171v16)

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3.0   ***AREA MAP***

An area map of the proposed Mont Belvieu Gas Plant is included on the following page. There are no schools within a radius of one mile of the Mont Belvieu facility.

1 Mile Radius

3,000 ft. Radius

SITE

N

SCALE

0   2000   4000

FEET

QUADRANGLE LOCATION

SOURCE: U.S.G.S. 7.5' QUADRANGLE, MONT BELVIEU, TX, 1994 (o29094G8).
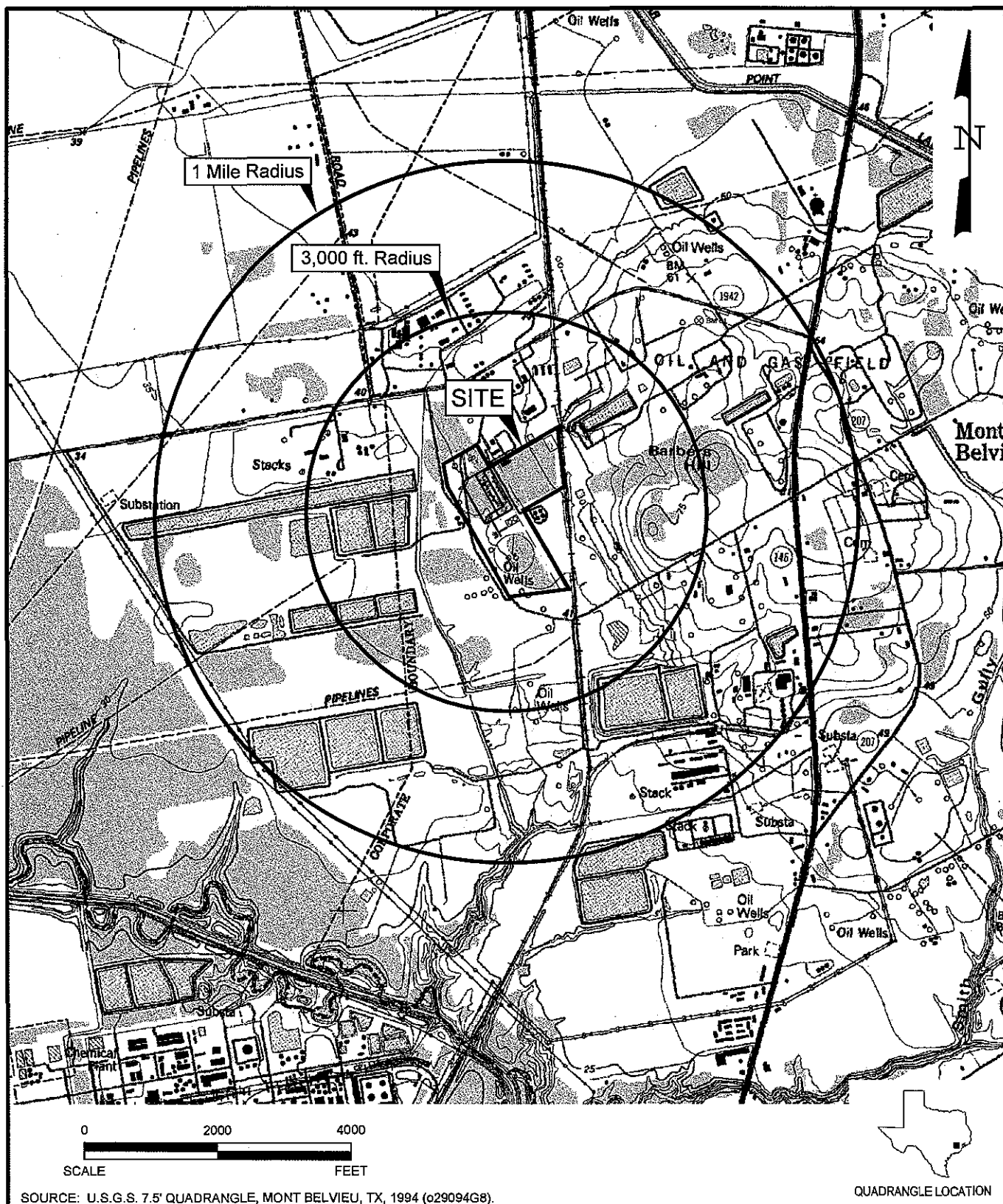
Environmental Resources Management			FIGURE 1 SITE LOCATION MAP Lone Star NGL Mont Belvieu Gas Plant Mont Belvieu, Texas	**ERM**
DESIGN: ST	DRAWN: EFC	CHKD.: ST		
DATE: 11/17/2011	SCALE: AS SHOWN	REV.:		
PROJ. NO.: H:\DWG\K11\0140876A1.dwg				

4.0 *PLOT PLAN*

A preliminary plot plan of the plant property showing the proposed project equipment, including air pollutant emission points, is included on the following page.

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

TRUE
NORTH

PLANT
NORTH

33°

50' ROAD ROW

ENTERPRISE PRODUCTS TEXAS OPERATING L.P.
CALLED 45.604 ACRES
VOL. 537, PG. 529
O.P.R.C.C., TX.

U.P.R.R. RAILROAD (100' ROW)

SHELL PIPE LINE CORPORATION
(25 YEAR GROUND LEASE OF 20.87 ACRES)
VOL. 434, PG. 177
D.R.C.C., TX.

T.M. BLAKE
A-350

FRAC I PROJECT

FM 1942 (100' R.O.W.)

GULF PRODUCTION COMPANY
CALLED 10 ACRES
VOL. 21, PG. 243
D.R.C.C., TX.

POND

VALERIE JEAN NIX
&
KAREN GILBERT CLAMON
CALLED 5.04 ACRES
VOL. 252, PG. 563
O.P.R.C.C., TX.

Environmental Resources Management

0   300   600

SCALE   FEET

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\K110140876c001.DWG, 11/18/2011 12:11:43 PM		

5.0   *PROCESS DESCRIPTION AND FLOW DIAGRAM*

Lone Star is submitting this GHG PSD permit application to authorize construction of a second fractionation train at the natural gas processing plant located in Mont Belvieu, Chambers County, Texas. The second train will fractionate Y-grade natural gas liquids through a series of trayed columns that separate the natural gas liquids into the constituent gas products, which include purity ethane, propane, butanes, and natural gasoline, for sale to customers.

Amine Unit
Natural gas liquid (NGL) feed will enter the Mont Belvieu FRAC II process and pass through the 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. The rich amine will be routed to an amine regenerator, where heat from the FRAC II process' hot oil system will enable the volatilization of the CO_2, H_2S, and hydrocarbons (primarily VOC) from the rich amine stream. The 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 will be routed to the FRAC II thermal oxidizer (TO) for combustion of H_2S and VOC, which combustion will generate SO_2 and CO_2. The Amine Unit flash tank emissions will 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 °F. The FRAC II TO will generate combustion-related GHG emissions. Table A-4 of the permit application provides the TO flue gas composition used to estimate GHG pollutant emission rates for the TO.

Mole Sieve Unit
From the Amine Unit, the NGL will be routed through a Molecular Sieve dehydration unit, where the water content in 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. Therefore, the only GHG emissions from this unit will be associated with fugitive piping equipment leaks.

Product Columns
From the Molecular Sieve dehydration unit, the NGL will be fed to a series of trayed columns for separation into constituent product gases. The NGL will enter each column in its middle section. Heat from the FRAC II process' independent hot oil system will be introduced to a reboiler located at the bottom of each column. The reboiler will vaporize a portion of the feed to produce stripping vapors inside the column. The vapors will rise through the column contacting downflowing liquid. The vapor leaving the top of the column will enter a condenser where heat is removed by the cooling medium and the vapors condensed. Liquid will be returned to the column as reflux to limit the loss of

heavy components overhead. The liquid leaving the lower part of the column will have the highest boiling point, whereas the hydrocarbon leaving the top of the column (either as vapor or liquid) will have the lowest boiling point.

No GHG emissions will be generated from processes downstream from the Amine Unit, except emissions from process heaters and fugitives, 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.

Process Heaters
The FRAC II train will employ a hot oil system that will provide heat to the process. By using oil, heat can be transferred to the FRAC II process with a minimum loss of heat to the oil, allowing for a quicker recovery to the desired temperature in a closed-loop system. The hot oil system will be a network of piping that will circulate hot oil through various areas of the FRAC II process. Lone Star 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 FRAC II process (i.e., piping to maintain desired temperatures on process streams).

The FRAC II process will have one Hot Oil heater rated at 270 million British thermal units per hour (MMBtu/hr) that will support the hot oil system. Additionally, the FRAC II process will utilize a Molecular Sieve regenerator 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. Both process heaters will be ducted to a common stack that will be equipped with Selective Catalytic Reduction (SCR) technology to significantly reduce NO_X emissions.

Flare
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 activities from both fractionation trains. No process streams (e.g. amine regenerator waste gas) 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. This PSD permit application addresses the emission increase from the existing flare associated with the addition of the FRAC II process. The flare will have pilot gas flow rate of 200 scfh. The flare will have a hydrocarbon destruction and removal efficiency (DRE) of 99.9% and will have a height of approximately 210 feet.

Thermal Oxidizer
The FRAC II process will utilize a thermal oxidizer to combust waste gas streams from the process. GHG emissions from the thermal oxidizer will result from waste gas and fuel gas combustion. The waste gas will be converted to CO_2 and water vapor so the carbon content in the waste gas is converted to CO_2e for GHG

pollutant estimations. More information on the TO's specifications may be found in Section 6.2 and Appendix A of this permit application.

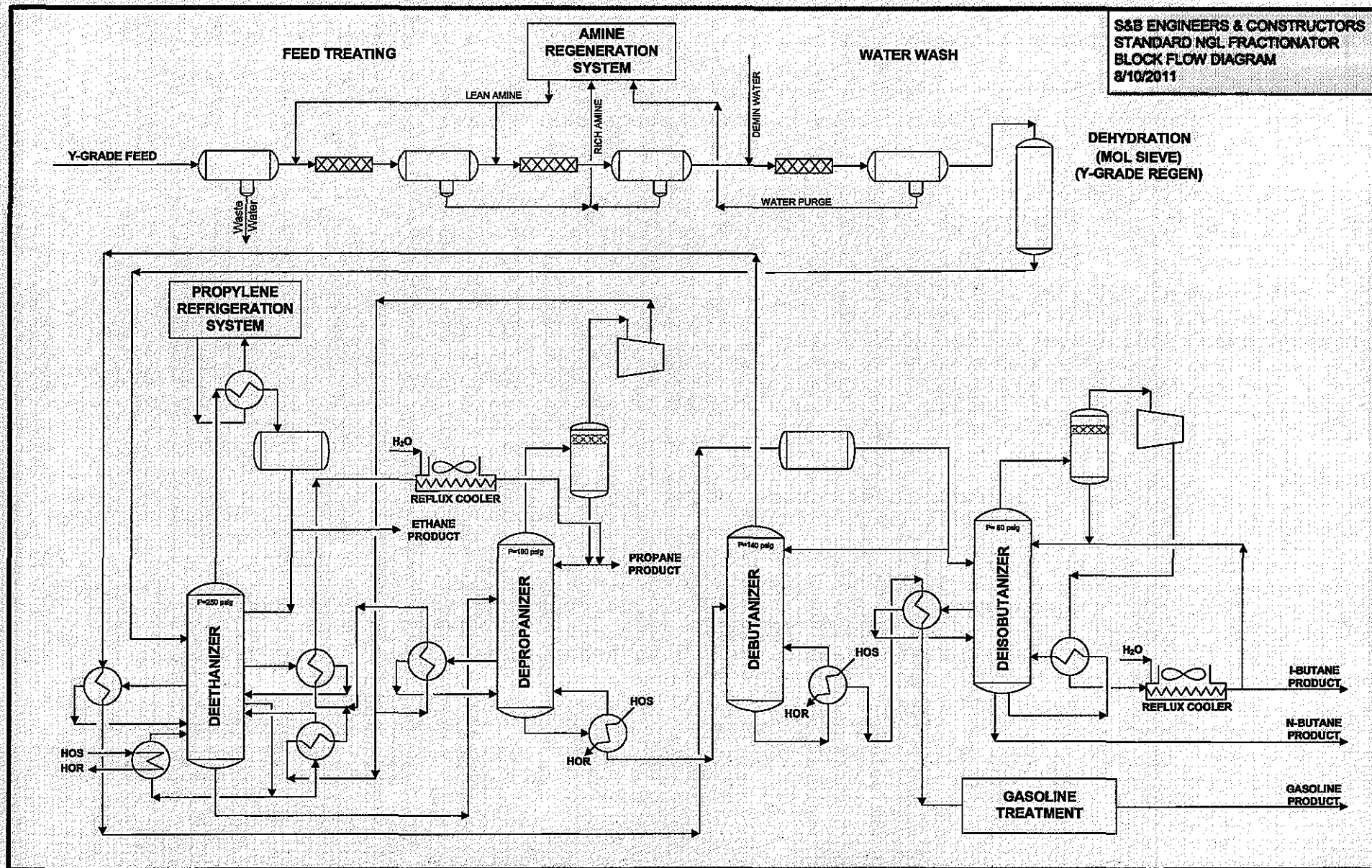Fugitives

Fugitive emissions of GHG pollutants, including CO_2 and methane, may result from piping equipment component 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 will implement the TCEQ 28LAER Leak Detection and Repair (LDAR) program for the entire Mont Belvieu site.

Non-GHG Sources

The FRAC II train will have process equipment that will not be sources of GHG emissions. The equipment include:

- Cooling water heat exchange system – a vapor mist cooling water heat exchange system will be utilized to cool process piping. The water mist will flow over the piping and will be collected for recycle. This cooling system will be addressed in the TCEQ standard permit application.

- Tanks – proposed process tanks will store fresh amine, Dowtherm heating oil (for the hot oil system), and used oil. Additionally, a pressurized propane storage tank will be used for the emergency generator (as described above). Finally, a pressurized ammonia (29% aqueous ammonia solution) tank will be used to store the ammonia to be injected into the SCR NOx control system for the two heaters. These tanks will be addressed in the TCEQ standard permit application.

- Electric-driven compressors – as process gas travels through pipelines and the plant processes, it loses pressure or energy due to the friction on the pipe walls or as part of the process. Electric-driven compressors will be utilized to maintain necessary gas pressure. These compressors will not be sources of pollutant emissions.

FEED TREATING

AMINE
REGENERATION
SYSTEM

WATER WASH

Y-GRADE FEED

LEAN AMINE

RICH AMINE

DEMIN WATER

DEHYDRATION
(MOL SIEVE)
(Y-GRADE REGEN)

Waste Water

WATER PURGE

PROPYLENE
REFRIGERATION
SYSTEM

H₂O

REFLUX COOLER

ETHANE
PRODUCT

PROPANE
PRODUCT

DEETHANIZER
P=250 psig

DEPROPANIZER
P=180 psig

DEBUTANIZER
P=140 psig

DEISOBUTANIZER
P= 80 psig

HOS
HOR

HOS

HOS

HOR

HOS

HOR

HOR

H₂O

REFLUX COOLER

I-BUTANE
PRODUCT

N-BUTANE
PRODUCT

GASOLINE
TREATMENT

GASOLINE
PRODUCT

6.0 GHG EMISSION RATE CALCULATIONS

This section provides a discussion of the calculation methodologies used to calculate GHG emissions, along with a summary of the total GHG emissions. Because GHG emissions may be a mixture of up to six compounds, the amount of GHG emissions calculated for the PSD applicability analysis is a sum of the applicable compounds emitted at each emissions unit. For each source, carbon dioxide equivalent (CO_2e) emissions are defined as the sum of the mass emissions of each individual GHG adjusted for its global warming potential (GWP). GWP means the ratio of the time-integrated radiative force from the instantaneous release of one kilogram of a trace substance relative to that of one kilogram of a reference gas (i.e., CO_2). The GWPs used to calculate the CO_2e emissions are summarized in Table 6-2 below.

TABLE 6-1: Global Warming Potentials

Pollutant	Global Warming Potential (100-yr time horizon)*
CO_2	1
CH_4	21
N_2O	310

* Based on Table A-1 to Subpart A of Part 98 – Global
  Warming Potentials (100-Year Time Horizon)

The calculation methodologies used to calculate GHG emissions for each project-related emission source type are described in the following sections. Appendix A includes detailed allowable emission rate calculation data tables, including an emission rate summary in Table A-1. A summary of proposed permit allowable GHG emission rates for units covered by this permit application is provided in Table 6-2 below.

TABLE 6-2: Summary of Potential GHG Emissions

GHG Source Description	CO_2 (tpy)	CH_4 (tpy)	N_2O (tpy)	CO_2e (tpy)
Hot Oil Heater	137,943.19	2.60	0.26	138,078.48
Regenerator Heater	23,501.43	0.44	0.04	23,524.48
Fugitives	0.002	0.001	--	0.03
Flare – MSS	52.40	--	--	52.40
Thermal Oxidizer	42,693.42	1.75E-1	1.79E-02	42,702.64
Total:	204,190.5	3.22	0.32	204,358.04

6.1 HOT OIL AND REGENERATOR HEATERS (EPN 013-SCR/RV)

A Hot Oil heater will be used to heat a low vapor pressure heating medium (hot oil) as an indirect heat transfer medium only. A Molecular Sieve Regenerator heater will be used to regenerate the dehydration beds. The stacks from both heaters will be ducted to a common stack. GHG emissions from the heaters are

generated as a result of combustion of natural gas fuel. The operating parameters, emission factors, calculation methodology used, and sample calculations for each heater are summarized below.

Operating Parameters
The design heat input rating of the Hot Oil heater is 270 MMBtu/hr and the design heat input rating of the Regenerator heater is 46 MMBtu/hr. Both heaters are designed to fire pipeline quality natural gas for a total annual operating time of 8,760 hours per year.

GHG Emission Factors
The GHG emissions from both heaters were calculated using default emission factors for natural gas provided in 40 CFR 98, Subpart C – General Stationary Fuel Combustion Sources. The applicable GHG pollutants for which natural gas emission factors were specified in 40 CFR 98, Subpart C are CO_2, CH_4, and N_2O. A summary of the emission factors used for each of these GHG pollutants is provided in Table 6-3 below, along with corresponding references.

TABLE 6-3: *Default GHG Emission Factors for Natural Gas*

GHG Pollutant	Default Emission Factor (kg/MMBtu)	Reference
CO_2	53.02	Table C-1 to Subpart C of 40 CFR Part 98
CH_4	1.00E-03	Table C-2 to Subpart C of 40 CFR Part 98
N_2O	1.00E-04	Table C-2 to Subpart C of 40 CFR Part 98

GHG Mass-Based Emissions
The mass-based annual emissions, in tons per year (tpy) for each GHG pollutant were calculated based on the default emission factors shown in Table 6-3 above, the design heat input rating of the heaters, the annual operating time, and a mass conversion factor according to the following equation:

Mass-based GHG emissions (tpy) = Design heat Input rating (MMBtu/hr) x Default Emission Factor (kg/MMBtu) x Annual Operating Time (hours/yr) x (1 tonne/1,000 kg) x (1.10 ton/tonne)

CO_2e Emissions
The CO_2e emissions were calculated using the mass-based emissions of each GHG pollutant listed above and the GWP values in Table A-1 of 40 CFR Part 98, Subpart A according to the following equation:

Annual CO_2e-based emissions (tons CO_2e/year) = [CO_2 annual mass-based emissions (ton/yr) x GWP for CO_2] + [CH4 annual mass-based emissions (ton/yr) x GWP for CH_4] + [N_2O annual mass-based emissions (ton/yr) x GWP for N_2O]

Sample Calculations for Hot Oil Heater

Annual Mass-Based CO_2 emissions (tpy) = 270 MMBtu/hr x 53.02 kg/MMBtu x 8,760 hours/yr x (1 tonne/1,000 kg) x (1.10 ton/tonne) = <u>137,943 tons CO_2</u>
Annual Mass-Based CH_4 emissions (tpy) = 270 MMBtu/hr x 0.001 kg/MMBtu x 8,760 hours/yr x (1 tonne/1,000 kg) x (1.10 ton/tonne) = <u>2.60 tons CH_4</u>
Annual Mass-Based N_2O emissions (tpy) = 270 MMBtu/hr x 0.0001 kg/MMBtu x 8,760 hours/yr x (1 tonne/1,000 kg) x (1.10 ton/tonne) = 0.26 <u>tons N_2O</u>

Annual CO_2e-based emissions (tpy) = [137,943 tons CO_2/yr x 1] + [2.60 tons CH_4/yr x 21] + [0.26 tons N_2O/yr x 310] = **<u>138,078.48 tons CO_2e</u>**

Sample Calculations for Regenerator Heater

Annual Mass-Based CO_2 emissions (tpy) = 46 MMBtu/hr x 53.02 kg/MMBtu x 8,760 hours/yr x (1 tonne/1,000 kg) x (1.10 ton/tonne) = <u>23,501 tons CO_2</u>

Annual Mass-Based CH_4 emissions (tpy) = 46 MMBtu/hr x 0.001 kg/MMBtu x 8,760 hours/yr x (1 tonne/1,000 kg) x (1.10 ton/tonne) = <u>0.44 tons CH_4</u>

Annual Mass-Based N_2O emissions (tpy) = 46 MMBtu/hr x 0.0001 kg/MMBtu x 8,760 hours/yr x (1 tonne/1,000 kg) x (1.10 ton/tonne) = 0.04 <u>tons N_2O</u>

Annual CO_2e-based emissions (tpy) = [23,501 tons CO_2/yr x 1] + [0.44 tons CH_4/yr x 21] + [0.04 tons N_2O/yr x 310] = **<u>23,524 tons CO_2e</u>**

6.2 THERMAL OXIDIZER (EPN 012-THERMO)

The FRAC II TO will be used to control the waste gas vent streams from the amine scrubbing system. GHG emissions from the FRAC II TO will result from combustion of fuel gas and waste gas from the process. The operating parameters, emission factors, calculation methodology used, and sample calculations are summarized below.

6.2.1 Emissions from fuel gas combustion

<u>Operating Parameters</u>
Emissions of CO_2, N_2O and CH_4 were based on a design average firing rate of 10 MMBtu/hr. All emissions were based on a total annual operating time of 8,760 hours per year. Flue gas composition data are provided below.

<u>GHG Emission Factors</u>
The CO_2, CH_4, and N_2O emissions from the TO were calculated using the default emission factors for natural gas provided in 40 CFR 98 Subpart C – General Stationary Fuel Combustion Sources. A summary of the emission factors used for

each of these GHG pollutants is provided in Table 6-3 above along with corresponding references.

GHG Mass-Based Emission Calculations

The mass-based emissions for CO_2, CH_4, and N_2O were calculated based on the default emission factors shown in Table 6-3 above, the design heat input rating of the TO, the annual operating time, and a mass conversion factor according to the following equation:

Mass-based CO_2, CH_4, and N_2O emissions (tpy) = Design heat Input rating (MMBtu/hr) x Default Emission Factor (kg/MMBtu) x Annual Operating Time (hr/yr) x (1 tonne/1,000 kg) x (1.10 ton/tonne)

CO_2e Emissions

The CO_2e emissions were calculated using the mass-based emissions of each GHG pollutant listed above and the GWP values in Table A-1 of 40 CFR Part 98, Subpart A, according to the following equation:

Annual CO_2e-based emissions (tons CO_2e/year) = [CO_2 annual mass-based emissions (ton/yr) x GWP for CO_2] + [CH_4 annual mass-based emissions (ton/yr) x GWP for CH_4] + [N_2O annual mass-based emissions (ton/yr) x GWP for N_2O]

Sample Calculations for TO

Annual Mass-Based CO_2 emissions (tpy) = 10MMBtu/hr x 53.02 kg/MMBtu x 8,760 hours/yr x (1 tonne/1,000 kg) x (1.10 ton/tonne) = 5119.74 tons CO_2

Annual Mass-Based CH_4 emissions (tpy) = 10 MMBtu/hr x 0.001 kg/MMBtu x 8,760 hours/yr x (1 tonne/1,000 kg) x (1.10 ton/tonne) = 0.097 tons CH_4

Annual Mass-Based N_2O emissions (tpy) = 10 MMBtu/hr x 0.0001 kg/MMBtu x 8,760 hours/yr x (1 tonne/1,000 kg) x (1.10 ton/tonne) = 0.01 tons N_2O

Annual CO2e-based emissions (tpy) = [5119.74 tons CO2/yr x 1] + [0.097 tons CH4/yr x 21] + [0.01 tons N2O/yr x 310] = 5124.76 tons CO2e

6.2.2   *Emissions from Waste gas combustion*

Annual emissions from waste gas combustion can be divided into the following:

- Direct CO_2 emissions from the waste gas – Direct CO_2 emissions from the waste gas were estimated based on the vendor provided data on the composition of the TO inlet stream. It was assumed that the TO does not control these direct CO_2 emissions.

- CO_2 generated by combustion of the waste gas – Emissions of CO_2 from combustion of waste gas were estimated using methodology provided in 40 CFR 98, Subpart W, Eqs. W-21 and W-36.

- Direct CH_4 emissions from the waste gas - Direct CH_4 emissions from the waste gas were estimated based on the vendor provided data on the composition of the TO inlet stream. A TO destruction efficiency of 99% was used to determine the direct CH_4 emissions.

- N_2O generated by combustion of waste gas – Emissions from N_2O from combustion of waste gas were estimated using Eq. W-40 provided in 40 CFR 98 Subpart W and the heat content of the waste gas as provided by vendor.

Table 6-4 provides the composition of TO inlet stream and Figure 6-1 provides the waste gas flow to the TO.

TABLE 6-4: Composition of the TO Inlet Stream

Stream	Component	Vapor Phase Composition (lb/hr)
TO Blower Suct[3]	Carbon Dioxide	7,143.06
	Methane	1.80
	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

Detailed calculations are provided in Appendix A. Sample calculations are provided below.

Sample Calculations for TO

CO2 generated by combustion of waste gas

CO_2 emissions from combustion of waste gas were calculated using methodologies presented in 40 CFR 98, Subpart W, Petroleum and Natural Gas Systems, Eq W-21 and W-36. Eq W-21, provided below, determines annual CO_2 emissions in cubic feet based on volume of gas sent to the TO, mole fraction of each hydrocarbon constituent, and number of carbon atoms in each hydrocarbon

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[3] Following streams are combined at the vent header to form the TO Blower Suction stream: DEA Regen Acid Gas, Rich Amine Drum Vent, and Compressor Seals. Therefore, the composition of the TO Blower Suction stream is used to determine GHG emissions from the TO. Compositions of the other streams are provided in Appendix A.

constituent. The cubic feet of CO_2 emissions can then be converted to mass based emissions using Eq W–36.

Appendix A, Table A-4, Carbon Flow for CO_2 Combustion Emissions, provides calculations based on Eq. W-21 and Eq. W-36.

$$E_{a,CO2} \text{ (combusted)} = \sum(\eta*V_a*Y_j*R_j) \qquad \text{(Eq. W-21)}$$

Where

$E_{a,CO2}$(combusted) = Contribution of annual combusted CO_2 emissions from TO stack in cubic feet, under actual conditions.
V_a = Volume of gas sent to flare in cubic feet, during the year.
η = Fraction of gas combusted by a burning flare (default is 0.98). For gas sent to an unlit flare, η is zero.
Y_j = Mole fraction of gas hydrocarbon constituents j (such as methane, ethane, propane, butane, and pentanes-plus).
R_j = Number of carbon atoms in the gas hydrocarbon constituent j: 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus).

$$\text{Mass}_{CO2} \text{ (combusted)} = E_{a,CO2} \text{ (combusted)}*\rho*GWP*10^{-3} \quad \text{Eq. W-36)}$$

Where

ρ = Density of CO_2, 0.052 kg/ft^3
GWP = Global warming potential, 1 for CO_2

As shown in Appendix A, Table A-4, CO_2 emissions from combustion of waste gas were estimated to be 6287.10 tpy.

N_2O generated by combustion of waste gas
Emissions from N_2O from combustion of waste gas were estimated using Eq. W-40 provided in 40 CFR 98 Subpart W and the heat content of the waste gas as provided by vendor.

$$N_2O = 10^{-3}*Fuel*HHV*EF*GWP \qquad \text{(Eq. W-40)}$$

Where

N_2O = Annual emissions in metric tons
Fuel = Annual mass or volume of fuel combusted (82,005.36 MMBtu/yr, calculated based on vendor provided information in Appendix A, Table A-4)
HHV = High heat value of the gas combusted (102.12 Btu/scf, as provided by vendor in Appendix A, Table A-4)
EF = Emission factor, 1 X 10^{-4} kg/MMBtu
10^{-3} = Conversion factor from kg to metric tons
GWP = Global warming potential, 310 for N_2O

As shown in Appendix A, Table A-4, N_2O emissions from combustion of waste gas were estimated to be 0.0082 tpy. Total CO_2e emissions from waste gas were estimated to be 42,704.64 tpy.

6.3   FLARE (EPN 004-FLARE)

6.3.1   Emissions from Pilots

Both the FRAC I and the proposed FRAC II trains at the Mont Belvieu plant will have a common flare. Emissions from flare pilot have already been addressed in the FRAC I permit application and therefore only the additional emissions from flare MSS activities are addressed below.

6.3.2   Emissions from MSS

The plant flare will control vent streams due to Maintenance, Startup, and Shutdown (MSS) activities. Typical plant maintenance activities include proving flow meters that measure the gas feed into the plant on a monthly basis, filter change outs, pump and compressor maintenance and startups, tank inspection activities, and the use of a parts washer. The operating parameters, GHG emission factors, calculation methodology used, and sample calculations are summarized below.

Operating Parameters
The flow rate and composition of MSS emissions as well as the duration and frequency of MSS events were estimated based on two events per year.

Emission Factors
Emissions of organic species routed to the flare were converted to emissions of CO_2, assuming a 100% conversion rate. CO_2 conversion factors for all organic components are presented below in Table 6-5.

TABLE 6-5:   Constituent CO_2 Factors for Flare-MSS Emissions

Constituent	Structure	MW (lb/lb-mole)	Mass Fraction[1] (%)	CO_2 Factor[2] (lb CO_2/lb)
Methane	CH_4	16	2.5%	2.75
Ethane	C_2H_6	30	68.1%	2.93
Propane	C_3H_8	44	21.4%	3.00
i-Butane	C_4H_{10}	58	2.5%	3.03
n-Butane	C_4H_{10}	58	3.9%	3.03
i-Pentane	C_5H_{12}	72	0.6%	3.06
n-Pentane	C_5H_{12}	72	0.5%	3.06
n-Hexane	C_6H_{14}	86	0.4%	3.07

[1] MSS emission composition provided by Lone Star.

[2] The CO_2 emission factor was estimated by assuming complete conversion of carbon in the organic feed stream to CO_2. CO_2 Factor (lb CO_2/lb) = Molecular Weight CO_2 (lb/lbmol) x Moles CO_2 per Mole Organic Component Combusted (lbmol /lbmol) ÷ Molecular Weight Organic Component (lb/lbmol).

GHG Mass-Based Emissions
The mass-based emissions of CO_2 were calculated based on the above operating

parameters and emission factors, molecular weights of organic components, and a mass conversion factor:

Mass-based GHG emissions per Organic Component (tpy) = Mass Fraction Organic Component (% weight) x MSS Emission Flow Rate (lb/event) x CO_2 Factor (lb/lb) x Event Frequency (event/yr) x (1 ton/2,000 lb)

The total emission rate of a GHG from MSS activities is equal to the sum of GHG emissions from each organic component of the vent stream. No other greenhouse gas emissions are generated.

CO_2e Emissions

The CO_2e emissions were calculated using the mass-based emissions of each GHG pollutant listed above and the GWP values in Table A-1 of 40 CFR Part 98, Subpart A, according to the following equation:

Annual CO_2e-based emissions (tons CO_2e/year) = [CO_2 annual mass-based emissions (ton/yr) x GWP for CO_2]

Sample Calculations

Annual Mass-Based CO_2 emissions for Methane (tpy) = 0.025 x 17,760 lb/event x 2.75 lb CO_2/lb x 2 events/yr x 1 ton/2,000 lb = 1.21 tons

Ethane: 0.681 x 17,760 lb/event x 2.93 lb CO_2/lb x 2 events/yr x 1 ton/2,000 lb = 35.48 tpy

Propane: 0.214 x 17,760 lb/event x 3.00 lb CO_2/lb x 2 events/yr x 1 ton/2,000 lb = 11.43 tpy

i-Butane: 0.025 x 17,760 lb/event x 3.03 lb CO_2/lb x 2 events/yr x 1 ton/2,000 lb = 1.34 tpy

n-Butane: 0.039 x 17,760 lb/event x 3.03 lb CO_2/lb x 2 events/yr x 1 ton/2,000 lb = 2.11 tpy

n-Pentane: 0.005 x 17,760 lb/event x 3.06 lb CO_2/lb x 2 events/yr x 1 ton/2,000 lb = 0.28 tpy

n-Hexane: 0.004 x 17,760 lb/event x 3.07 lb CO_2/lb x 2 events/yr x 1 ton/2,000 lb = 0.22 tons

Total CO_2 emissions (tpy) = 1.21 tpy + 35.48 tpy + 11.43 tpy + 1.34 tpy + 2.11 tpy + 0.28 tpy + 0.22 tpy = 52.40 tons

Annual CO_2e-based emissions (tpy) = [52.40 tons CO_2/yr x 1] = **52.40 tons CO_2e**

6.4 **FUGITIVES (EPN 019-FUG)**

Fugitive emissions of CO_2 and CH_4 occur from various piping equipment, including valves, connectors, pumps, and compressors in gas service. These emissions, which occur while process fluid is in contact with the equipment, depend upon the type of component and the phase of the fluid within the equipment. All of the GHG components would be in the inlet NGL, residue gas, and molecular sieve regeneration gas streams. All of the subsequent equipment would not contain GHG components.

GHG Emission factors
GHG emissions from fugitive pipeline component leaks were estimated using the oil and gas processing factors from the TCEQ's Draft Technical Guidance Package (TGP) for Equipment Leak Fugitives (October 2000). Emission control credits from implementation of TCEQ's 28LAER leak detection and repair (LDAR) program, as well as annual connector monitoring, were applied to the monitored components. Speciation of the fugitive GHG emissions was based on the relative constituent concentrations in the various process streams. Fugitive emission rate estimates are presented in Table A-5.

GHG Mass-Based Emissions
The mass-based emissions CO_2 were calculated based on the above operating parameters and emission factors, molecular weights of organic components, and a mass conversion factor:

Mass-based GHG emissions per Organic Component (tpy) = Mass Fraction GHG Component (% weight) x Emission Factor (lb/hr/component) x Operating Hours (8,760/yr) x (1 ton/2,000 lb) x (1 – 28VHP control efficiency)

The total emission rate of a GHG from fugitive emissions is equal to the sum of GHG emissions from the CH_4 and CO_2 constituents in the vent stream. No other greenhouse gas emissions are generated.

CO_2e Emissions
The CO_2e emissions were calculated using the mass-based emissions of each GHG pollutant listed above and the GWP values in Table A-1 of 40 CFR Part 98, Subpart A, according to the following equation:

Annual CO_2e-based emissions (tons CO_2e/year) = [CO_2 annual mass-based emissions (ton/yr) x GWP for CO_2] + [CH_4 annual mass-based emissions (ton/yr) x GWP for CH_4]

Sample Calculations
Annual Mass-Based CH_4 emissions for Gas/Vapor Service Valves (tpy) = 881 valves x 0.00992 lb/hr/component x 0.02% CH_4 x (1 ton/2,000 lb) x 8,760 hr/yr = 2.7×10^{-4} tons CH_4

Annual Mass-Based CO_2 emissions for Gas/Vapor Service Valves (tpy) = 881 valves x 0.00992 lb/hr/component x 0.03% CO_2 x (1 ton/2,000 lb) x 8,760 hr/yr = 3.49×10^{-4} tons CO_2

Annual CO_2e-based emissions (tpy) = [3.49×10^{-4} tons CO_2/yr x 1] + [2.7×10^{-4} tons CH_4/yr x 21] = **6.05** x 10^{-3} **tons CO_2e**

7.0   *REGULATORY APPLICABILITY ANALYSIS*

This section of the application provides a review of pertinent federal air quality regulations that apply to the FRAC II unit GHG emission sources.

7.1   *TAILORING RULE – PSD*

On June 3, 2010, the U.S. EPA issued the final Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule (Tailoring Rule) which establishes an approach to addressing GHG emissions from stationary sources under the Clean Air Act (CAA) permitting programs. Under the CAA, new major stationary sources of certain air pollutants, defined as "regulated NSR pollutants," and major modifications to existing major sources are required to, among other things, obtain a PSD permit prior to construction or major modification. The term "major stationary source" is defined as a stationary source that emits, or has potential emissions of 100 tons per year (tpy) if the source is in one of 28 source categories listed in 40 CFR §52.21(b)(1)(i)(a). If the source is not a listed source category, then the major modification trigger is 250 tpy of regulated NSR pollutants. A major modification is defined as, "any physical change in or change in the method of operation of a major stationary source that would result in a significant emissions increase of a regulated NSR pollutant; and a significant net emissions increase of that pollutant from the major stationary source."

As required by the Tailoring Rule, beginning on January 2, 2011, GHGs are a regulated NSR pollutant under the PSD major source permitting program when they are emitted by new sources or modifications in amounts that meet the Tailoring Rule's set of applicability thresholds, which phase in over time. For purposes of the PSD Tailoring Rule, GHGs are a single air pollutant defined as the aggregate group of the following six gases:

- Carbon Dioxide (CO_2)

- Nitrous Oxide (N_2O)

- Methane (CH_4)

- Hydrofluorocarbons (HFCs)

- Perfluorocarbons (PFCs)

- Sulfur Hexafluoride (SF_6)

Under Step 2 of the Tailoring Rule (which began on July 1, 2011), PSD applies to the GHG emissions from a proposed modification to an existing source if:

- The potential GHG emissions from the existing source are equal to or greater than 100,000 tpy on a CO_2e basis *and* equal to or greater than 250 tpy on a mass basis;[4] and

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[4] As natural gas processing plants are not included in the list of 28 source categories specified in 40 CFR §52.21(b)(1)(i)(a), the applicable mass-based threshold for the Mont Belvieu site is 250 tpy.

- The emissions increase *and* the net emissions increase of GHGs from the modification would be equal to or greater than 75,000 tpy on a CO_2e basis *and* greater than zero tpy on a mass basis.

The potential GHG emissions from the existing Mont Belvieu facility are greater than 100,000 tpy on a CO_2e basis and 250 tpy on a mass basis. Therefore, the existing Mont Belvieu facility qualifies as a major source of GHG emissions. To determine the applicability of PSD permitting requirements to the GHG emissions from the proposed FRAC II project, the potential GHG emissions were compared to the applicability threshold for major modifications as shown in Table 7-1 below.

TABLE 7-1: *Comparison of Potential GHG Emissions with PSD Tailoring Rule Applicability Threshold*

Pollutant	Potential Emissions		PSD Applicability Threshold	
	CO_2e (tpy)	Mass-Based (tpy)	CO_2e (tpy)	Mass-Based (tpy)
GHG	204,358.04	204,194.0	75,000	0

As shown above, the potential emissions from the proposed FRAC II project are expected to be greater than 75,000 tpy on a CO_2e basis and 0 tpy on a mass basis. Therefore, the proposed FRAC II project is considered subject to requirements of the PSD program for GHG emissions.

PSD regulations require that subject sources perform a Best Available Control Technology (BACT) review for each new or modified emission unit. Accordingly, BACT requirements for each emission unit as part of the proposed FRAC II project are addressed in Section 8.0 of this application.

In addition to performing BACT, a source subject to requirements of the PSD program must analyze impacts on ambient air quality to assure that no violation of any National Ambient Air Quality Standards (NAAQS) or PSD Increment Standards will result, perform ambient monitoring (if required), and analyze impacts on soil, vegetation, and visibility. In addition, sources or modifications that would impact Class I areas (e.g., national parks) may be subject to additional requirements to protect air quality related values (AQRV) that have been identified for such areas. However, as there have been no NAAQS or PSD Increment Standards established or proposed for CO_2 or any of the other well-mixed GHGs, and GHGs are currently not included in the list of pollutants specified, dispersion modeling to demonstrate compliance with these standards is currently not required even when PSD is triggered for GHGs.[5,6] Further, as stated in EPA's PSD and Title V guidance

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[5] 75 FR 31520, Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, June 3, 2010

[6] PSD and Title V Permitting Guidance for Greenhouse Gases, U.S. EPA Office of Air and Radiation, March 2011

document for Greenhouse Gases (March 2011), ambient monitoring or Class I impacts analyses are not required to be performed for GHGs.[7]

7.2   *TAILORING RULE – TITLE V*

The Tailoring Rule also addresses the implementation of the federal operating permits program promulgated under Title V of the CAA. The CAA requires that major sources must apply for, and operate in accordance with, an operating permit that contains conditions necessary to assure compliance with all CAA requirements applicable to the source. Under Step 2 of the Tailoring Rule, any existing or newly constructed GHG emission sources (not already subject to Title V) are subject to subject to Title V permitting requirements as a result of their GHG emissions if they have potential emissions equal to or greater than 100,000 tpy CO_2e *and* 100 tpy GHGs on a mass basis. Based on its potential to emit, the Mont Belvieu facility (FRAC I and FRAC II) will be classified as a major source of GHG emissions and shall be subject to the requirements of the Title V program for GHGs.

As per the Tailoring Rule, applicants subject to Title V permitting requirements for GHGs can submit the Title V applications within 12 months of commencing operation or on or before such earlier date as the permitting authority may establish.[8] In Texas, 30 TAC 122 addresses the Texas implementation of the federal operating permits program promulgated under Title V of the Clean Air Act and requires applicants to obtain a Title V operating permit prior to start of operation of the Project. However, as TCEQ is currently not implementing GHG requirements of the Title V program and as EPA has not issued guidance on federal implementation of the Title V program requirements for GHGs in Texas, Lone Star will submit the Title V permit application for GHGs based on any future guidance issued by EPA or TCEQ.

7.3   *MANDATORY GHG REPORTING RULE*

The EPA's Greenhouse Gas Mandatory Report Rule (MRR) specifies requirements for owners and operators of certain facilities that directly emit GHG as well as for certain fossil fuel suppliers and industrial GHG suppliers. The GHG reporting requirements and related monitoring, recordkeeping, and reporting requirements of this part apply to the owners and operators of any facility that is located in the United States and that meets the requirements of either paragraph 40 CFR §98.2(a)(1), (a)(2), or (a)(3) of the rule; and any supplier that meets the requirements of paragraph 40 CFR §98.2(a)(4) of the rule. The rule does not require control of greenhouse gases; rather, it requires only that sources above certain threshold levels monitor and report actual emissions for the previous calendar year. As such, the monitoring, recordkeeping, and reporting requirements contained in the GHG MRR are not applicable under the PSD regulations and are not required to be addressed in PSD permit applications.

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[7] Ibid

[8] 75 FR 31527, Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, June 3, 2010.

8.0   *BACT ANALYSIS*

This section presents the BACT analysis in support of the proposed FRAC II PSD Permit Application. Pursuant to 40 CFR §52.21(j)(2), each new major source or major modification must employ BACT for each regulated NSR pollutant that it would have the potential to emit in significant amounts. BACT is defined in 40 CFR §52.21(b)(12) as:

> *"an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results."*

The BACT requirements of the PSD program only apply to the pollutants that are subject to PSD review and the emission units that are newly installed or physically modified. In this case, the emissions increase of GHGs from the sources that are part of the proposed project exceeds the corresponding PSD *de minimis* emission rates and are, therefore, subject to BACT. No other pollutant increases as part of this project exceed the significance levels of the PSD program. Therefore, all other criteria pollutants will be reviewed under the TCEQ minor source permitting program.

8.1   *GHG EMISSION SOURCES*

The GHG-emitting sources associated with the Project that are subject to
requirements of the PSD program and for which a BACT analysis was performed
are listed below:

- Hot Oil Heater (natural gas-fired);

- Molecular Sieve Regenerator Heater (natural gas-fired);

- Flare (continuous pilot operation and intermittent MSS emissions control);

- Thermal Oxidizer (control of Amine Unit waste gas); and

- Fugitive Emissions.

8.2   *BACT METHODOLOGY*

In a memorandum dated December 1, 1987, the United States Environmental
Protection Agency (U.S. EPA) stated its preference for a "top-down" BACT
analysis.[9] After determining if any NSPS is applicable, the first step in this
approach is to determine, for the emission unit in question, the most stringent
control available for a similar or identical source or source category. If it can be
shown that this level of control is technically, environmentally, or economically
infeasible for the unit in question, then the next most stringent level of control is
determined and similarly evaluated. This process continues until the BACT level
under consideration cannot be eliminated by any substantial or unique technical,
environmental, or economic objections. Presented below are the five basic steps
of a top-down BACT review as identified by the U.S. EPA.[10]

Step 1 – Identify All Control Technologies
Available control technologies are identified for each emission unit in question.
The following methods are typically used to identify potential technologies:

1. Research the EPA's Reasonably Available Control Technology
   (RACT)/BACT/Lowest Achievable Emission Rate (LAER) Clearinghouse
   (RBLC) database;

2. Determine BACT by regulatory agencies for other similar sources or air
   permits and permit files from federal or state agencies;

3. Use engineering experience with similar control applications;

4. Survey air pollution control equipment vendors, and/or;

5. Review available literature from industrial, technical, or trade organizations.

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[9] U.S. EPA, Office of Air and Radiation. Memorandum from J.C. Potter to the Regional
Administrators. Washington, D.C. December 1, 1987.
[10] U.S. EPA. *Draft New Source Review Workshop Manual*, Chapter B. Research Triangle Park, North
Carolina. October, 1990.

Step 2 – Eliminate Technically Infeasible Options
After the identification of control options, an analysis is conducted to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that prohibit the implementation of the control technology or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits, such as a New Source Performance Standard (NSPS). It should be noted that as of the date of this permit application, EPA has not promulgated any NSPS that contain emissions limits for GHGs.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness
Once technically infeasible options are removed from consideration, the remaining options are ranked based on their control effectiveness. If there is only one remaining option, or if all of the remaining technologies could achieve equivalent control efficiencies, ranking based on control efficiency is not required.

Step 4 – Evaluate Most Effective Controls and Document Results
Beginning with the most efficient control option in the ranking, detailed economic, energy, and environmental impact evaluations are performed. If a control option is determined to be economically feasible without adverse energy or environmental impacts, it is not necessary to evaluate the remaining options with lower control efficiencies.

The economic evaluation centers on the cost effectiveness of the control option. Costs of installing and operating control technologies are estimated and annualized following the methodologies outlined in the U.S. EPA's OAQPS Control Cost Manual (CCM) and other industry resources.[11]

Step 5 – Select BACT
In the final step, one pollutant-specific control option is proposed as BACT for each emission unit under review based on evaluations from the previous step.

The EPA has consistently interpreted the statutory and regulatory BACT definitions as containing two core requirements that the agency believes must be met by any BACT determination, regardless of whether the "top-down" approach is used. First, the BACT analysis must include consideration of the most stringent available control technologies (i.e., those which provide the "maximum degree of emissions reduction"). Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of "energy, environmental, and economic impacts".

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[11] Office of Air Quality Planning and Standards (OAQPS), *EPA Air Pollution Control Cost Manual,* Sixth Edition, EPA 452-02-001 http://www.epa.gov/ttn/catc/products.html#cccinfo), Daniel C. Mussatti & William M. Vatavuk, January 2002.

8.3   ***"TOP-DOWN" BACT ANALYSIS***

In order to identify the potential control technologies for the GHG emission sources associated with this Project, Lone Star conducted a search of the EPA's RBLC database, other federal air permits, and controls applied to sources similar in nature to the source categories being evaluated for this project. The RBLC is maintained by the EPA and was created to assist applicants in selecting appropriate control technologies for new and modified sources. Appendix B of this permit application contains the results of the RBLC queries as well as other supporting documentation.

Additionally, Lone Star reviewed sector-specific Energy Guides for a number of industries published by EPA's ENERGY STAR program and technical GHG control measure "white papers" published by the EPA for specific industrial sectors. While a specific sector paper on natural gas processing plants has not been released by the EPA, Lone Star relied on guidance provided for similar sources in other industrial sectors, as applicable.

Finally, an attempt was made to use the EPA's GHG Mitigation Strategies Database, which includes specific performance and cost data on current and developing GHG control measures. However, this database was not available during the preparation of this BACT analysis. It should be noted here that as GHG BACT is a new and evolving requirement, all methods typically used to identify potential control technologies were not necessarily available or relevant for preparing this GHG BACT analysis.

Based on review of the available information resources, the technologies/measures listed in Table 8-1 below were identified as being potentially applicable for controlling GHG emissions from each emission source associated with the proposed project.

TABLE 8-1: **Summary of Potentially Applicable Control Technologies**

Source Descriptions	Potentially Applicable Control Technologies
Hot Oil Heater and Molecular Sieve Regenerator Heater	Combustion air controls – limitations on excess air
	Fuel selection/switching
	Fuel gas preheating
	Efficient heater and burner design
	Periodic tune-ups and maintenance for optimal thermal efficiency
	Heat recovery
	Oxygen trim control
	Proper operation and good combustion practices
Flare – Continuous pilot operation and intermittent MSS control	Proper operation and good combustion practices
	Fuel selection
	Minimize duration of Maintenance, Startup, and Shutdown activities
	Flare gas recovery
Thermal Oxidizer	Use of thermal oxidizers employing heat recovery (e.g. regenerative or recuperative thermal oxidizers)
	Use of other planned combustion processes in lieu of a separate thermal oxidizer
	Proper design, operation and good combustion practices
Fugitive Emissions	Leak detection and repair (LDAR) program for fugitive piping components
Plant-wide	Carbon capture and sequestration
	Use of electric-driven engines

The top-down BACT analysis for GHG emissions from each applicable emission source from the proposed project is presented in Table 8-2 below.

Table 8-2: Top-Down BACT Analysis for GHG Emissions

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	
Source Description	PSD Pollutant	Control Technology	Control Technology Description	RBLC Database Information	Technical Feasibility	Typical Overall Control Efficiency	Cost Effectiveness ($/ton)	STEP 5. SELECT BACT
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	👍

Table 8-2: Top-Down BACT Analysis for GHG Emissions

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	
Source Description	PSD Pollutant	Control Technology	Control Technology Description	RBLC Database Information	Technical Feasibility		Typical Overall Control Efficiency	Cost Effectiveness ($/ton)	STEP 5. SELECT BACT
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

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	
Source Description	PSD Pollutant	Control Technology	Control Technology Description	RBLC Database Information	Technical Feasibility	Typical Overall Control Efficiency	Cost Effectiveness ($/ton)	STEP 5. SELECT BACT
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. 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. Further, the waste stream has 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.			
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	Not listed in RBLC Database	Feasible.	NA	NA – Selected as BACT	👍

Table 8-2: Top-Down BACT Analysis for GHG Emissions

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	
Source Description	PSD Pollutant	Control Technology	Control Technology Description	RBLC Database Information	Technical Feasibility	Typical Overall Control Efficiency	Cost Effectiveness ($/ton)	STEP 5. SELECT BACT
			that Lonestar shall implement as BACT is provided in Section 8.5.					
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	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	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.	

Table 8-2: Top-Down BACT Analysis for GHG Emissions

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	
Source Description	PSD Pollutant	Control Technology	Control Technology Description	RBLC Database Information	Technical Feasibility	Typical Overall Control Efficiency	Cost Effectiveness ($/ton)	STEP 5. SELECT BACT
			regenerating amine solution rich in CO_2, and electrical needs for system equipment.		gas) is being combusted, and add-on controls are not technically feasible. Therefore, CCS is considered technically infeasible for the 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.			

Table 8-2: Top-Down BACT Analysis for GHG Emissions

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	
Source Description	PSD Pollutant	Control Technology	Control Technology Description	RBLC Database Information	Technical Feasibility	Typical Overall Control Efficiency	Cost Effectiveness ($/ton)	STEP 5. SELECT BACT
					Moreover, because the electricity required to run all of the above 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.			

Table 8-2: Top-Down BACT Analysis for GHG Emissions

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)	
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.

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

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

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

8.4   SUMMARY – SELECTED BACT

A summary of the proposed BACT for each applicable emission source part of the proposed project is provided in Table 8-3 below.

Table 8-3:   *Proposed GHG BACT*

Source Descriptions	BACT Options
Hot Oil Heater	Combustion air controls - limitations on excess air; Fuel selection/switching; Efficient heater and burner design;
Regeneration Heater	Periodic tune-ups and maintenance for optimal thermal efficiency; Heat recovery; Proper operation and good combustion practices.
Flare – Continuous pilot operation	Efficient heater and burner design
	Periodic tune-ups and maintenance for optimal thermal efficiency
Flare - MSS	Minimize duration of Maintenance, Startup, and Shutdown activities
Thermal Oxidizer	Proper design, operation and good combustion practices
Fugitive Emissions	Implementation of a 28LAER LDAR program
	Use of dry compressor seals
	Use of rod packing for reciprocating compressors
	Use of low-bleed gas-driven pneumatic controllers or compressed air-driven pneumatic controllers
Plant-wide	Electric-driven compressor engines

8.5   GOOD COMBUSTION PRACTICES

The emissions of GHGs can be controlled by using good combustion practices for operating and maintaining the combustion equipment to maximize fuel efficiency which will minimize emissions of CO_2 on an energy output basis. By burning lesser fuel to perform the same amount of work, lesser amounts of CO_2, CH_4, and N_2O will be emitted to the atmosphere. A summary of the good combustion practices identified based on EPA guidance that Lonestar will implement are

summarized in Table 8-4 below.[12]

Table 8-4: Summary of Good Combustion Practices

Good Combustion Technique	Practice	Standard
Operator practices	- Official documented operating procedures, updated as required for equipment or practice change - Procedures include startup, shutdown, malfunction - Operating logs/record keeping	- Maintain written site specific operating procedures in accordance with Good Combustion Practices (GCPs), including startup, shutdown, and malfunction
Maintenance knowledge	- Training on applicable equipment and procedures	- Equipment maintained by personnel with training specific to equipment
Maintenance practices	- Official documented maintenance procedures, updated as required for equipment or practice change - Routinely scheduled evaluation, inspection, overhaul as appropriate for equipment involved - Follow vendor recommendation Maintenance logs/record keeping	- Maintain site specific procedures for best/optimum maintenance practices - Scheduled periodic evaluation, inspection, overhaul as appropriate.
Fuel quality (analysis); Use of clean fuels (natural gas)	- Monitor fuel quality - Periodic fuel sampling and analysis - Lonestar shall use only pipeline quality natural gas. Natural gas burns more cleanly than fuels with higher hydrocarbon content	- Fuel analysis where composition could vary and where of significance to sulfur content
Combustion air distribution	- Adjustment of air distribution system based on visual observations - Adjustment of air distribution based on continuous or periodic monitoring	- Routine and periodic adjustments and checks
Good engineering design	- Since the plant is a new construction, all sources shall be operating at the best efficiency possible by design.	- Keep record of manufacturer's certificate and maintain the engines as per the manufacturer's guidelines.
Conducting visible emissions observations	- Visible emissions observations shall be made and recorded in accordance with the requirements specified in 40 CFR §64.7(c).	- Maintain schedule and records of the visible emission observation made.

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[12] http://www.epa.gov/ttnatw01/iccr/dirss/gcp.pdf

Emission Rate Estimates
Appendix A

December 2, 2011
Project No. 0140876

Environmental Resources Management
15810 Park Ten Place, Suite 300
Houston, Texas 77084
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TABLE A-1

GHG Emission Rate Summary

Source Description	CO_2 (tpy)	CH_4 (tpy)	N_2O (tpy)	CO_2e (tpy)
Hot Oil Heater	137,943.19	2.60	0.26	138,078.48
Regenerator Heater	23,501.43	0.44	0.04	23,524.48
Fugitives	0.002	0.001	--	0.03
MSS - Flare	52.40	--	--	52.40
Thermal Oxidizer	42,693.42	1.75E-01	1.79E-02	42,702.64
Total	204,190.45	3.22	0.32	204,358.04

NOTES:

Low concentrations of miscellaneous air contaminants may be present.
Other components present in trace quantities are not represented.
This representation does not cover all operating scenarios.

TABLE A-2

Hot Oil Heater Emission Rate Calculations

EPN	FIN	Design Heat Input (MMBtu/hr)	Annual Operation (hrs)	Fuel Type	Annual Fuel Use [1] (MMscf/yr)	Emission Factors [2]		
						CO$_2$ (kg/MMBtu)	CH$_4$ (kg/MMBtu)	N$_2$O (kg/MMBtu)
013-SCR/VE	013-SCR/VE	270	8,760	NG	2,319	53.02	0.001	0.0001

EPN	FIN	Annual Emissions (ton/yr) [3]			
		CO$_2$	CH$_4$	N$_2$O	CO$_2$e
013-SCR/VE	013-SCR/VE	137,943	2.60	0.26	138,078

NOTES:

1) Fuel Heating Value =   1,020   Btu/scf
2) From 40 CFR 98.33, Tables C-1 and C-2
3) Sample Calculations:

Heater annual emissions: [Design heat input (MMBtu/hr)] x [Emission Factor (kg/MMBtu)] x [8,760 hr/yr] x [1 tonne/1,000 kg] x [1.10 ton/tonne] = ton/yr
and
Heater annual emissions: [CO$_2$ annual emissions (ton/yr)] x [1] + [CH$_4$ annual emissions (ton/yr)] x [21] + [N$_2$O annual emissions (ton/yr)] x [310] = ton CO$_2$e/yr

TABLE A-3

Mole Sieve Regenerator Heater Emission Rate Calculations

EPN	FIN	Design Heat Input (MMBtu/hr)	Annual Operation (hrs)	Fuel Type	Annual Fuel Use [1] (MMscf/yr)	Emission Factors [2]		
						CO$_2$ (kg/MMBtu)	CH$_4$ (kg/MMBtu)	N$_2$O (kg/MMBtu)
013-SCR/VE	013-SCR/RV	46	8,760	NG	395	53.02	0.001	0.0001

EPN	FIN	Annual Emissions (ton/yr) [3]			
		CO$_2$	CH$_4$	N$_2$O	CO$_2$e
013-SCR/VE	013-SCR/RV	23,501	0.44	0.04	23,524

NOTES:

1) Fuel Heating Value =   1,020   Btu/scf
2) From 40 CFR 98.33, Tables C-1 and C-2
3) Sample Calculations:

   Heater annual emissions: [Design heat Input (MMBtu/hr)] x [Emission Factor (kg/MMBtu)] x [8,760 hr/yr] x [1 tonne/1,000 kg] x [1.10 ton/tonne] = ton/yr
   and
   Heater annual emissions: [CO$_2$ annual emissions (ton/yr)] x [1] + [CH$_4$ annual emissions (ton/yr)] x [21] + [N$_2$O annual emissions (ton/yr)] x [310] = ton CO$_2$e/yr

TABLE A-4

Thermal Oxidizer Emission Rate Calculations

Emissions from Fuel Gas Combustion:
Emissions from fuel gas combustion are based on 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

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

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

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

CO_2 Emission Rates:

Emission Point	CO_2 (lb/hr)	CO_2 (tpy)
012-THERMO	1,084.71	4,751.04

CO_2e Emission Rates:

Emission Point	CO_2e (lb/hr)	CO_2e (tpy)
012-THERMO	1,085.86	4,756.06

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.
4) Flue gas data provided by vendor.

Emissions from Waste Gas Combustion:

Emissions from waste gas combustion are based on 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.

Process Stream 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, 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

Streams	Component	Vapor Phase Composition[2] lb/hr	Streams	Component	Vapor Phase Composition[2] lb/hr	Streams	Component	Vapor Phase Composition[2] 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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Emissions from Waste Gas	Direct CO_2 Emissions from Waste Gas[1]		CO_2 from Combustion of Waste Gas[2]	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.
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.

Carbon Flow for CO_2 Combustion Emissions							
Compound	No. of Carbons	Mol Wt.	Flow Rate[1]	Concentration[1]	Carbon Weighted Flow[2]	CO_2 Emissions from Combustion[3]	
			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:
1) Vendor provided data
2) Based on mole fraction and number of carbon atoms in each compound.
3) 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.

	Total CO_2e Emissions (tpy)
Fuel Gas Combustion	5,124.76
Waste Gas	37,577.89
Total	42,702.64

TABLE A-5

Equipment Leak Fugitives (EPN 019-FUG)

Emission Estimate

Component	Service	Emission Factor[1]	Number of Components	LDAR Program	Control Efficiency	Methane (wt %)	CO₂ (wt %)	Methane Emissions[2] (lb/hr)	Methane Emissions[2] (tpy)	CO₂ Emissions[2] (lb/hr)	CO₂ Emissions[2] (tpy)
Valves[3]	Gas/Vapor	0.00992	881	28LAER	97%	0.02%	0.03%	0.0001	0.000271	0.0001	0.0003
	Light Oil	0.0055	2,461	28LAER	97%	0.02%	0.03%	0.0001	0.000420	0.0001	0.0005
	Heavy Oil	0.0000185		28LAER	0%	0.02%	0.03%	0	0	0	0
Pumps[4]	Light Oil	0.02866	50	28LAER	93%	0.02%	0.03%	0.0000	0.000104	0.0000	0.0001
	Heavy Oil	0.00113		28LAER	0%	0.02%	0.03%	0	0	0	0
Flanges/Connectors	Gas/Vapor	0.00086	1,159	28LAER	75%	0.02%	0.03%	0.0001	0.000258	0.0001	0.0003
	Light Oil	0.000243	2,835	28LAER	75%	0.02%	0.03%	0.0000	0.000178	0.0001	0.0002
	Heavy Oil	0.00000086		28LAER	75%	0.02%	0.03%	0	0	0	0
Compressors	Gas/Vapor	0.0194	3	28LAER	95%	0.02%	0.03%	0.0000	0.000003	0.0000	0.0000
Relief Valves[5]	Gas/Vapor	0.0194	51	28LAER	100%	0.02%	0.03%	0.00	0.00	0.00	0.00
	Light Oil	0.0165	34	28LAER	100%	0.02%	0.03%	0.00	0.00	0.00	0.00
Other[6]	Light Oil	0.0165	1	28LAER	97%	0.02%	0.03%	0.0000001	0.000001	0.0000002	0.000001
							Total:	**0.0003**	**0.0012**	**0.0004**	**0.0016**

Global Warming Potential (GWP) Factor: 21   1

CO₂e Emissions (Annual Emissions x GWP):   0.03   Methane   0.0016   CO₂

Total CO₂e Emissions: 0.028   tpy

NOTES:

1) Emission factors are for "Oil and Gas Production Operations" from TCEQ Guidance Package For Equipment Leak Fugitives Dated October 2000
2) Annual emissions based on operation of fugitives 8,760 hours/year
3) Relief valves in liquid service included in counts for light liquid valves per TCEQ guidance
4) Leakless pumps not included in light liquid pump count
5) Relief valves in gaseous service are equipped with rupture disks, resulting in 100% control (per TCEQ guidance)
6) "Other" includes diaphragms, dump arms, hatches, instruments, meters, polished rods, and vents and are assumed to have same control efficiency as valves.

TABLE A-6

Flare MSS Emissions (EPN 004-FLARE)
Greenhouse Gas Emissions

Flow rate[1] (lb/event)	Event duration (hr)	Events/yr	DRE
17,760	12	2	99%

CO_2 emissions

Constituent	Structure	MW (lb/lb-mole)	Mass Fraction (%)[1]	Maximum Flow Rate (lb/event)	Maximum Flow Rate (lb/hr)	CO₂ Factor[2] (lb CO₂/lb)	CO₂ Emissions (lb/hr)	CO₂ Emissions (tpy)
Methane	CH_4	16	2.5%	439.63	36.64	2.75	100.75	1.21
Ethane	C_2H_6	30	68.1%	12,094.84	1,007.90	2.93	2,956.52	35.48
Propane	C_3H_8	44	21.4%	3,808.76	317.40	3.00	952.19	11.43
i-Butane	C_4H_{10}	58	2.5%	440.85	36.74	3.03	111.48	1.34
n-Butane	C_4H_{10}	58	3.9%	695.00	57.92	3.03	175.75	2.11
n-Pentane	C_5H_{12}	72	0.5%	90.65	7.55	3.06	23.08	0.28
n-Hexane	C_6H_{14}	86	0.4%	72.15	6.01	3.07	18.46	0.22
						TOTAL	4,366.89	52.40

CO_2e Emission Rates[3,4]:

EPNs	CO₂e (lb/hr)	CO₂e (tpy)
EPN 004-FLARE	4,366.89	52.40

NOTES:

1) Flow rate and speciation was provided by ETP.
2) The CO_2 emission factor is estimated by assuming complete conversion of the carbon in the organic feed stream to CO_2.
3) CO_2e emissions are calculated by multiplying the mass-based emissions of CO_2, CH_4, and N_2O with the Global Warming Potentials for each.
4) Flare emissions presented in this application represent MSS emissions generated by FRAC II train.

Supporting Documentation for BACT Analysis
Appendix B

December 2, 2011
Project No. 0140876

Environmental Resources Management
15810 Park Ten Place, Suite 300
Houston, Texas 77084
(281) 600-1000

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RBLCID	FACILITY_NAME	FACILITY_STATE	PERMIT_NUM	PERMIT_ISSUANCE_DATE	FACILITY_DESCRIPTION	PROCESS_NAME	PRIMARY_FUEL	THROUGHPUT	THROUGHPUT_UNIT	PROCESS_NOTES	POLLUTANT	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT	CASE-BY-CASE_BASIS	PERCENT_EFFICIENCY	EMISSION_LIMIT_2	EMISSION_LIMIT_2_UNIT	POLLUTANT_COMPLIANCE_NOTES
AL-0231	NUCOR DECATUR LLC	AL	712-0037	6/12/2007	THE FACILITY PRODUCES STEEL COILS PRIMARILY FROM STEEL SCRAP USING THE ELECTRIC ARC FURNACE (EAF) PROCESS.	VACUUM DEGASSER BOILER	NATURAL GAS	95	MMBTU/H		Carbon Dioxide		0.061	LB/MMBTU	BACT-PSD	0	5.8	LB/H	
LA-0148	ACTIVATED CARBON FACILITY	LA	PSD-LA-727	5/28/2008	THE FACILITY WILL USE COAL AS A FEEDSTOCK TO MANUFACTURE ROUGHLY 350 MILLION POUNDS OF ACTIVATED CARBON (AC) PER YEAR.	MULTIPLE HEARTH FURNACES / AFTERBURNERS	COAL	7.78	LB/YR E +08	4 MULTI-HEARTH FURNACES. PROCESSES LIGNITE COAL. ALSO COMBUSTS 13.2 MM BTU /HR NATURAL GAS TO BALANCE HEAT LOADS.	Carbon Dioxide	AFTERBURNER AND GOOD COMBUSTION PRACTICES	37.6	LB/H	BACT-PSD	0	0		
*LA-0248	DIRECT REDUCTION IRON PLANT	LA	PSD-LA-751	1/27/2011	The DRI process reduces the iron oxide content of iron ore pellets into iron metal through direct contact with a reducing gas. The effectiveness of this reduction process is called metallization, and the process equipment will be designed to achieve a metallization rate of at least 92% of the oxides within the ore. The reduction will take place in a countercurrent vertical shaft furnace, where reducing gas passes up through iron oxide pellets, which feed through the furnace by gravity. The major elements of the DRI process include the following: (1) iron oxide preparation; (2) reducing gas preparation; (3) DRI reactor shaft furnace; (4) spent reducing gas preparation for reuse; (5) DRI product handling; and (6) ancillary operations, including a package boiler, two cooling towers, and a flare for emergency situations.	DRI-108 - DRI Unit #1 Reformer Main Flue Stack	Iron Ore and Natural Gas	12168	Billion Btu/yr	The Direct Reduction Iron process consists of two main components, a Reformer and the DRI reactor. Natural gas passes through special catalyst tubes where the natural gas dissociates into a reducing gas rich in carbon monoxide and hydrogen, which are the primary chemicals used to remove the oxygen from the iron ore. The reducing gas is fed in from the bottom of the DRI Reactor. The gas flows countercurrent to the descending iron ore pellets. At the top of the reactor, the partially spent reducing gas exits and is recompressed, enriched with natural gas, preheated, and transported back to the gas reformer. The reformer reforms the mixture back to 95% hydrogen plus carbon monoxide, which is then ready for re use by the direct reduction furnace. Some of the reducing gas that has already passed over the iron ore in the DRI reactor (the spent reducing gas is also known as top gas) is mixed with the natural gas that is being combusted in the reformer and is also therefore combusted.	Carbon Dioxide	the best available technology for controlling CO2e emissions from the DRI Reformer is good combustion practices, the Acid gas separation system, and Energy Integration. BACT shall be good combustion practices, which will be adhered to maintain low levels of fuel consumption by the LNB burners.	0		BACT-PSD	0	0		Due to production rate and product quality variability in any production process, production rates should be inclusive of all production at the facility, both of regular and off-spec materials. Additionally, natural gas is consumed in the DRI process as both a raw material (for the formation of reducing gas) and as a fuel (for heating to reaction temperatures). All sources of natural gas consumption at the Reformer should be included in the analysis. BACT is no more than 13 decatherms of natural gas per tonne of DRI (11.79 MM Btu/ton of DRI). Compliance with the BACT limit shall be determined on the basis of total natural gas consumption, divided by total production (including regular and off-spec DRI product) of the facility on a 12-month rolling average.
*LA-0248	DIRECT REDUCTION IRON PLANT	LA	PSD-LA-751	1/27/2011	The DRI process reduces the iron oxide content of iron ore pellets into iron metal through direct contact with a reducing gas. The effectiveness of this reduction process is called metallization, and the process equipment will be designed to achieve a metallization rate of at least 92% of the oxides within the ore. The reduction will take place in a countercurrent vertical shaft furnace, where reducing gas passes up through iron oxide pellets, which feed through the furnace by gravity. The major elements of the DRI process include the following: (1) iron oxide preparation; (2) reducing gas preparation; (3) DRI reactor shaft furnace; (4) spent reducing gas preparation for reuse; (5) DRI product handling; and (6) ancillary operations, including a package boiler, two cooling towers, and a flare for emergency situations.	DRI-208 - DRI Unit #2 Reformer Main Flue Stack	Iron ore and Natural Gas	12168	Billion Btu/yr	The Direct Reduction Iron process consists of two main components, a Reformer and the DRI reactor. Natural gas passes through special catalyst tubes where the natural gas dissociates into a reducing gas rich in carbon monoxide and hydrogen, which are the primary chemicals used to remove the oxygen from the iron ore. The reducing gas is fed in from the bottom of the DRI Reactor. The gas flows countercurrent to the descending iron ore pellets. At the top of the reactor, the partially spent reducing gas exits and is recompressed, enriched with natural gas, preheated, and transported back to the gas reformer. The reformer reforms the mixture back to 95% hydrogen plus carbon monoxide, which is then ready for re use by the direct reduction furnace. Some of the reducing gas that has already passed over the iron ore in the DRI reactor (the spent reducing gas is also known as top gas) is mixed with the natural gas that is being combusted in the reformer and is also therefore combusted.	Carbon Dioxide	the best available technology for controlling CO2e emissions from the DRI Reformer is good combustion practices, the Acid gas separation system, and Energy Integration. BACT shall be good combustion practices, which will be adhered to maintain low levels of fuel consumption by the LNB burners.	0		BACT-PSD	0	0		Due to production rate and product quality variability in any production process, production rates should be inclusive of all production at the facility, both of regular and off-spec materials. Additionally, natural gas is consumed in the DRI process as both a raw material (for the formation of reducing gas) and as a fuel (for heating to reaction temperatures). All sources of natural gas consumption at the Reformer should be included in the analysis. BACT is no more than 13 decatherms of natural gas per tonne of DRI (11.79 MM Btu/ton of DRI). Compliance with the BACT limit shall be determined on the basis of total natural gas consumption, divided by total production (including regular and off-spec DRI product) of the facility on a 12-month rolling average.
*LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	LA	PSD-LA-752	8/16/2011	1827 MW POWER PLANT (PRE-PROJECT). NATURAL GAS IS PRIMARY FUEL; NO. 2 & NO. 4 FUEL OIL ARE SECONDARY FUELS. PROJECT INVOLVES DECOMMISSIONING OF 2 BOILERS AND THE CONSTRUCTION OF 2 COMBINED CYCLE GAS TURBINES WITH DUCT BURNERS, A NATURAL GAS-FIRED AUXILIARY BOILER, A DIESEL GENERATOR, 2 COOLING TOWERS, A FUEL OIL STORAGE TANK, A DIESEL-FIRED FIREWATER PUMP, AND AN ANHYDROUS AMMONIA TANK. FUELS FOR THE TURBINES INCLUDE NATURAL GAS, NO. 2 FUEL OIL, AND ULTRA LOW SULFUR DIESEL.	AUXILIARY BOILER (AUX-1)	NATURAL GAS	338	MM BTU/HR		Carbon Dioxide	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	0		BACT-PSD	0	0		

RBLCID	FACILITY_NAME	FACILITY_STATE	PERMIT_NUM	PERMIT_ISSUANCE_DATE	FACILITY_DESCRIPTION	PROCESS_NAME	PRIMARY_FUEL	THROUGHPUT	THROUGHPUT_UNIT	PROCESS_NOTES*	POLLUTANT	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT	CASE-BY-CASE_BASIS	PERCENT_EFFICIENCY	EMISSION_LIMIT_2	EMISSION_LIMIT_2_UNIT	POLLUTANT_COMPLIANCE_NOTES
*LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	LA	PSD-LA-752	8/16/2011	1827 MW POWER PLANT (PRE-PROJECT). NATURAL GAS IS PRIMARY FUEL; NO. 2 & NO. 4 FUEL OIL ARE SECONDARY FUELS. PROJECT INVOLVES DECOMMISSIONING OF 2 BOILERS AND THE CONSTRUCTION OF 2 COMBINED CYCLE GAS TURBINES WITH DUCT BURNERS, A NATURAL GAS-FIRED AUXILIARY BOILER, A DIESEL GENERATOR, 2 COOLING TOWERS, A FUEL OIL STORAGE TANK, A DIESEL-FIRED FIREWATER PUMP, AND AN ANHYDROUS AMMONIA TANK. FUELS FOR THE TURBINES INCLUDE NATURAL GAS, NO. 2 FUEL OIL, AND ULTRA LOW SULFUR DIESEL.	EMERGENCY DIESEL GENERATOR	DIESEL	1250	HP		Carbon Dioxide	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	0		BACT-PSD	0	0		
*LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	LA	PSD-LA-752	8/16/2011	1827 MW POWER PLANT (PRE-PROJECT). NATURAL GAS IS PRIMARY FUEL; NO. 2 & NO. 4 FUEL OIL ARE SECONDARY FUELS. PROJECT INVOLVES DECOMMISSIONING OF 2 BOILERS AND THE CONSTRUCTION OF 2 COMBINED CYCLE GAS TURBINES WITH DUCT BURNERS, A NATURAL GAS-FIRED AUXILIARY BOILER, A DIESEL GENERATOR, 2 COOLING TOWERS, A FUEL OIL STORAGE TANK, A DIESEL-FIRED FIREWATER PUMP, AND AN ANHYDROUS AMMONIA TANK. FUELS FOR THE TURBINES INCLUDE NATURAL GAS, NO. 2 FUEL OIL, AND ULTRA LOW SULFUR DIESEL.	EMERGENCY FIRE PUMP	DIESEL	350	HP		Carbon Dioxide	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	0		BACT-PSD	0	0		
OK-0135	PRYOR PLANT CHEMICAL	OK	2008-100-C PSD	2/23/2009		CARBON DIOXIDE VENT		36.5	T/H	36.5 TONS/H CO2 VENTED LIMIT	Carbon Dioxide	GOOD OPERATION PRACTICES.	3.65	LB/H	BACT-PSD	0	0		
TX-0347	CHOCOLATE BAYOU PLANT	TX	PSD-TX-854	10/16/2001	BP AMOCO PROPOSES TO INCREASE ITS ETHYLENE PRODUCTION FROM THE NO. 1 AND NO. 2 OLEFINS UNITS AT THE CHOCOLATE BAYOU PLANT. TO ACHIEVE THE PRODUCTION INCREASE, BP AMOCO PLANS TO REPLACE THE EXISTING FURNACES AT NO. 1 OLEFINS AND EITHER REPLACE OR RETROFIT THE FURNACES AT THE NO. 2 OLEFINS UNIT. LOW-NOX TECHNOLOGY WILL BE UTILIZED ON THESE FURNACE REPLACEMENTS OR RETROFITS. BP AMOCO IS REQUESTING THIS CONSOLIDATED PERMIT INCLUDE A FLEXIBLE EMISSION CAP FOR ALL CRACKING FURNACES IN NO. 1 AND NO. 2 OLEFINS UNITS AND A FLEXIBLE EMISSION CAP FOR THE EXTERNAL FLOATING ROOF TANKS.	REGENERATION HEATER, DD9-201					Carbon Dioxide	NONE INDICATED	2.1	LB/H	BACT-PSD	0	9.3	T/YR	

RBLCID	FACILITY_NAME	FACILITY_STATE	PERMIT_NUM	PERMIT_ISSUANCE_DATE	FACILITY_DESCRIPTION	PROCESS_NAME	PRIMARY_FUEL	THROUGH PUT	THROUGH PUT_UNIT	PROCESS_NOTES"	POLLUTANT	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT	CASE-BY-CASE_BASIS	PERCENT_EFFICIENCY	EMISSION_LIMIT_2	EMISSION_LIMIT_2_UNIT	POLLUTANT_COMPLIANCE_NOTES
TX-0347	CHOCOLATE BAYOU PLANT	TX	PSD-TX-854	10/16/2001	BP AMOCO PROPOSES TO INCREASE ITS ETHYLENE PRODUCTION FROM THE NO. 1 AND NO. 2 OLEFINS UNITS AT THE CHOCOLATE BAYOU PLANT. TO ACHIEVE THE PRODUCTION INCREASE, BP AMOCO PLANS TO REPLACE THE EXISTING FURNACES AT NO. 1 OLEFINS AND EITHER REPLACE OR RETROFIT THE FURNACES AT THE NO. 2 OLEFINS UNIT. LOW-NOX TECHNOLOGY WILL BE UTILIZED ON THESE FURNACE REPLACEMENTS OR RETROFITS. BP AMOCO IS REQUESTING THIS CONSOLIDATED PERMIT INCLUDE A FLEXIBLE EMISSION CAP FOR ALL CRACKING FURNACES IN NO. 1 AND NO. 2 OLEFINS UNITS AND A FLEXIBLE EMISSION CAP FOR THE EXTERNAL FLOATING ROOF TANKS.	DECOKE STACK, DDF-201					Carbon Dioxide	NONE INDICATED	36.5	LB/H	BACT-PSD	0	7.2	T/YR	
TX-0481	AIR PRODUCTS BAYTOWN II	TX	PSD-TX-1044 / 35873	11/2/2004	THIS FACILITY GETS RAW SYNTHESIS GAS FROM EXXON&S SYNTHESIS GAS MANUFACTURING UNIT. THE RAW SYNGAS STREAM FROM THE EXXON PLANT, CONSISTING OF CO2, CO, H2, H2S, COS, HCN, NH3 AND METHANE, IS PIPED TO THE AIR PRODUCTS PLANT WHERE THE ACID GASES AND AMMONIA WILL BE REMOVED BY AIR PRODUCTS2 RECTISOL UNIT. THE PRODUCTS PRODUCED INCLUDE CO, AND TWO PURE SYNTHESES GAS PRODUCTS. THESE PRODUCTS ARE DISTRIBUTED TO CUSTOMERS VIA PIPELINES. AN IMPURE SYNGAS IS ALSO PRODUCED AND USED OFFSITE AS FUEL. THE NEW PROCESS WILL CONVERT A PORTION OF THE SYNGAS TO HYDROGEN. THE HYDROGEN WILL BE PURIFIED AND DISTRIBUTED TO CUSTOMERS.	EMERGENCY GENERATOR				CO EMISSIONS ARE ELIGIBLE FOR PSD	Carbon Dioxide		2.24	LB/H	BACT-PSD	0	0.99	T/YR	
TX-0550	BASF FINA NAFTA REGION OLEFINS COMPLEX	TX	36644	2/10/2010	OLEFINS COMPLEX, ETHYLENE CRACKING FACILITY	N-11, REACTOR REGENERATION EFFLUENT	METHANE	5064.83	CFS	THE RACT/BACT/LAER DATABASE WAS SEARCHED FOR THIS FACILITY TYPE AND NO EXACT PROCESS WAS FOUND.⊡ ⊡ THE MSS PROCESS AT N-11 IS SIMILAR TO N-10. THE CATALYST FROM THE DP REACTOR IS HEATED AND ANY COKE PRESENT ON THE CATALYST IS CONVERTED TO CO OR CO2. UNIT USED GOOD COMBUSTION PRACTICES TO MEET BACT SINCE GOOD COMBUSTION PRACTICES ARE GOOD BUSINESS PRACTICE, NO ADDITIONAL CONDITIONS OR MONITORING WERE REQUIRED FOR THIS AMENDMENT.	Carbon Dioxide		0		BACT-PSD	0	0		NO EMISSION LIMITS AVAILABLE
TX-0550	BASF FINA NAFTA REGION OLEFINS COMPLEX	TX	36644	2/10/2010	OLEFINS COMPLEX, ETHYLENE CRACKING FACILITY	N-38, DECOKING DRUM	METHANE	26625	LB COKE/CYCLE	THE RACT/BACT/LAER DATABASE WAS SEARCHED FOR THIS FACILITY TYPE AND SIMILAR PROCESSES WERE FOUND BUT THERE WERE NO PROJECT NOTES. ⊡ ⊡ THE DECOKING DRUM AND FURNACE TUBES ARE HEATED AND ANY COKE PRESENT ON THE CATALYST IS CONVERTED TO CO OR CO2. UNIT USED GOOD COMBUSTION PRACTICES TO MEET BACT. SINCE GOOD COMBUSTION PRACTICES ARE GOOD BUSINESS PRACTICE, NO ADDITIONAL CONDITIONS OR MONITORING WERE REQUIRED FOR THIS AMENDMENT.	Carbon Dioxide		0		BACT-PSD	0	0		NO EMISSION LIMITS AVAILABLE

RBLCID	FACILITY_NAME	FACILITY_STATE	PERMIT_NUM	PERMIT_ISSUANCE_DATE	FACILITY_DESCRIPTION	PROCESS_NAME	PRIMARY_FUEL	THROUGHPUT	THROUGHPUT_UNIT	PROCESS_NOTES"	POLLUTANT	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT	CASE-BY-CASE_BASIS	PERCENT_EFFICIENCY	EMISSION_LIMIT_2	EMISSION_LIMIT_2_UNIT	POLLUTANT_COMPLIANCE_NOTES
TX-0550	BASF FINA NAFTA REGION OLEFINS COMPLEX	TX	36644	2/10/2010	OLEFINS COMPLEX, ETHYLENE CRACKING FACILITY	N-10, CATALYST REGENERATION EFFLUENT	METHANE	2100	CFS	THE RACT/BACT/LAER (RBLC) DATABASE WAS SEARCHED FOR THIS FACILITY TYPE. A MARATHON PETROLEUM DETROIT REFINERY CATALYST REGENERATION UNIT AND A BP WEST COAST PRODUCTS CATALYST REGENERATION UNIT USED GOOD COMBUSTION PRACTICES TO MEET BACT. THESE WERE THE ONLY FACILITIES LISTED IN THE RBLC DATABASE FOR THIS FACILITY TYPE. ▨ GOOD COMBUSTION PRACTICES ARE USED FOR EPN N-10.THE CATALYST FROM THE ACETYLENE CONVERTER MAIN BEDS, ACETYLENE CONVERTER GUARD BED, METHYL ACETYLENE, PROPADIENE CONVERTERS, C4 DIOLEFIN HYDROGENATION REACTOR AND FIRST STAGE DIOLEFINS REACTOR IS HEATED AND ANY COKE PRESENT ON THE CATALYST IS CONVERTED TO CO OR CO2. SINCE GOOD COMBUSTION PRACTICES ARE GOOD BUSINESS PRACTICE, NO ADDITIONAL CONDITIONS OR MONITORING WERE REQUIRED FOR THIS AMENDMENT.	Carbon Dioxide		0		BACT-PSD	0	0		NO EMISSION LIMITS AVAILABLE

RBLCID	FACILITY_NAME	FACILITY_STATE	PERMIT_NUM	FACILITY_DESCRIPTION	PROCESS_NAME	PRIMARY_FUEL	THROUGHPUT	THROUGHPUT_UNIT	PROCESS_NOTES	POLLUTANT	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT	CASE-BY-CASE_BASIS	PERCENT_EFFICIENCY	EMISSION_LIMIT_2	EMISSION_LIMIT_2_UNIT	POLLUTANT_COMPLIANCE_NOTES
MD-0040	CPV ST CHARLES	MD	CPCN CASE NO. 9129	640 MW GENERATING FACILITY	INTERNAL COMBUSTION ENGINE - EMERGENCY FIRE WATER PUMP	DIESEL	300	HP		Methane		3	G/HP-H	BACT-PSD	0	0		COMBINED LIMIT OF NOX AND NON-METHANE HYDROCARBON
OH-0261	RUMPKE SANITARY LANDFILL, INC	OH	14-05824, 14-06292	HAMILTON COUNTY LANDFILL WITH LANDFILL GAS PRODUCTION	NEW SOLID WASTE DISPOSAL WITH LANDFILL GAS GENERATION		42760000	TONS OF WASTE EXPANS	LANDFILL EXPANSION OF 42,760,000 TONS OF COMPACTED WASTE CAPACITY LANDFILL ADDITION WITH AN ADDITIONAL 8,531 MMCF OF LANDFILL GAS PRODUCTION/YR.	Methane	ACTIVE GAS COLLECTION AND CONTROL SYSTEM: FLARE; LANDFILL GAS RECOVERY FOR SALE/USE; OR CONTROL BY A THERMAL OXIDIZER	1563	T/YR	BACT-PSD	0	0		
OH-0261	RUMPKE SANITARY LANDFILL, INC	OH	14-05824, 14-06292	HAMILTON COUNTY LANDFILL WITH LANDFILL GAS PRODUCTION	EXISTING SOLID WASTE DISPOSAL WITH LANDFILL GAS GENERATION		32272000	TONS OF WASTE	EXISTING FACILITY PRIOR TO APPLICATION FOR EXPANSION.	Methane	ACTIVE GAS COLLECTION AND CONTROL SYSTEM: FLARE; LANDFILL GAS RECOVERY FOR SALE/USE; OR CONTROL BY A THERMAL OXIDIZER	599	T/YR	BACT-PSD	0	0		
OH-0261	RUMPKE SANITARY LANDFILL, INC	OH	14-05824, 14-06292	HAMILTON COUNTY LANDFILL WITH LANDFILL GAS PRODUCTION	FUGITIVE EMISSIONS FROM LANDFILL AND GAS COLLECTION SYSTEM					Methane		45029	T/YR	BACT-PSD	0	0		
OH-0330	RUMPKE SANITARY LANDFILL	OH	07-00574	MUNICIPAL SOLID WASTE LANDFILL, MODIFICATION TO INCREASE THE CAPACITY AND TO ALLOW FOR THE DISPOSAL OF ASBESTOS CONTAINING WASTES.	MUNICIPAL WASTE LANDFILL				THE EXISTING LANDFILL IS NOT SUBJECT TO THE REQUIREMENTS OF NSPS SUBPART WWW BECAUSE THE 5-YEAR NMOC EMISSION REPORT SUBMITTED ON 6/1/2013 SHOWED NMOC EMISSIONS WELL BELOW 50 MG/YR. WHEN NMOC EMISSIONS ARE CALCULATED TO EQUAL OR EXCEED THE 50 MG LIMIT THE FACILITY WILL INSTALL LANDFILL WELLS THAT MEET THE REQUIREMENTS OF THE SUBPART.	Methane	4 ENCLOSED COMBUSTORS AND 5 CANDLESTICK FLARES; AND MAIN OPEN FLARE FOR EXISTING LANDFILL	78712	T/YR	N/A	0	500	PPM	THIS IS THE PERMITTED LIMIT THAT INCLUDES THE FUTURE EXPANSION.
OH-0330	RUMPKE SANITARY LANDFILL	OH	07-00574	MUNICIPAL SOLID WASTE LANDFILL, MODIFICATION TO INCREASE THE CAPACITY AND TO ALLOW FOR THE DISPOSAL OF ASBESTOS CONTAINING WASTES.	ENCLOSED COMBUSTORS (4)	LANDFILL GAS				Methane	COMBUSTORS ARE THE CONTROL	299.91	LB/H	N/A	0	1309.66	T/YR	CALCULATED FROM EMISSION FACTORS FROM USEPA'S LANDFILL GAS EMISSIONS MODEL AND AP-42 SECTION 2.4
OH-0330	RUMPKE SANITARY LANDFILL	OH	07-00574	MUNICIPAL SOLID WASTE LANDFILL, MODIFICATION TO INCREASE THE CAPACITY AND TO ALLOW FOR THE DISPOSAL OF ASBESTOS CONTAINING WASTES.	CANDLESTICK FLARE (5)	LANDFILL GAS				Methane	FLARE IS CONTROL	25	LB/H	N/A	0	109.45	T/YR	
OH-0330	RUMPKE SANITARY LANDFILL	OH	07-00574	MUNICIPAL SOLID WASTE LANDFILL, MODIFICATION TO INCREASE THE CAPACITY AND TO ALLOW FOR THE DISPOSAL OF ASBESTOS CONTAINING WASTES.	OPEN FLARE	LANDFILL GAS				MAIN FLARE FOR CONTROL OF LANDFILL GAS AND ODORS FROM EXISTING LANDFILL. NOT SUBJECT TO THE CONTROL REQUIREMENTS OF THE NSPS, SUBPART WWW, BECAUSE NON-METHANE ORANIC COMPOUND EMISSIONS ARE CALCULATED TO BE LESS THAN 50 MEGAGRAMS/YR.	Methane	FLARE IS CONTROL	25	LB/H	N/A	0	109.45	T/YR	
*LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	LA	PSD-LA-763	1827 MW POWER PLANT [PRE-PROJECT]. NATURAL GAS IS PRIMARY FUEL; NO. 2 & NO. 4 FUEL OIL ARE SECONDARY FUELS. PROJECT INVOLVES DECOMMISSIONING OF 2 BOILERS AND THE CONSTRUCTION OF 2 COMBINED CYCLE GAS TURBINES WITH DUCT BURNERS, A NATURAL GAS-FIRED AUXILIARY BOILER, A DIESEL GENERATOR, 2 COOLING TOWERS, A FUEL OIL STORAGE TANK, A DIESEL-FIRED FIREWASTER PUMP, AND AN ANHYDROUS AMMONIA TANK. FUELS FOR THE TURBINES INCLUDE NATURAL GAS, NO. 2 FUEL OIL, AND ULTRA LOW SULFUR DIESEL.	AUXILIARY BOILER (AUX-1)	NATURAL GAS	326	MM BTU/HR		Methane	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	0		BACT-PSD	0	0		

RBLCID	FACILITY_NAME	FACILITY_STATE	PERMIT_NUM	FACILITY_DESCRIPTION	PROCESS_NAME	PRIMARY_FUEL	THROUGHPUT	THROUGHPUT_UNIT	PROCESS_NOTES*	POLLUTANT	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT	CASE-BY-CASE_BASIS	PERCENT_EFFICIENCY	EMISSION_LIMIT_2	EMISSION_LIMIT_2_UNIT	POLLUTANT_COMPLIANCE_NOTES
*LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	LA	PSD-LA-752	1627 MW POWER PLANT (PRE-PROJECT). NATURAL GAS IS PRIMARY FUEL; NO. 2 & NO. 4 FUEL OIL ARE SECONDARY FUELS. PROJECT INVOLVES DECOMMISSIONING OF 2 BOILERS AND THE CONSTRUCTION OF 2 COMBINED CYCLE GAS TURBINES WITH DUCT BURNERS, A NATURAL GAS-FIRED AUXILIARY BOILER, A DIESEL GENERATOR, 2 COOLING TOWERS, A FUEL OIL STORAGE TANK, A DIESEL-FIRED FIREWASTER PUMP, AND AN ANHYDROUS AMMONIA TANK. FUELS FOR THE TURBINES INCLUDE NATURAL GAS, NO. 2 FUEL OIL, AND ULTRA LOW SULFUR DIESEL.	EMERGENCY DIESEL GENERATOR	DIESEL	1250	HP		Methane	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	0		BACT-PSD	0	0		
*LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	LA	PSD-LA-752	1627 MW POWER PLANT (PRE-PROJECT). NATURAL GAS IS PRIMARY FUEL; NO. 2 & NO. 4 FUEL OIL ARE SECONDARY FUELS. PROJECT INVOLVES DECOMMISSIONING OF 2 BOILERS AND THE CONSTRUCTION OF 2 COMBINED CYCLE GAS TURBINES WITH DUCT BURNERS, A NATURAL GAS-FIRED AUXILIARY BOILER, A DIESEL GENERATOR, 2 COOLING TOWERS, A FUEL OIL STORAGE TANK, A DIESEL-FIRED FIREWASTER PUMP, AND AN ANHYDROUS AMMONIA TANK. FUELS FOR THE TURBINES INCLUDE NATURAL GAS, NO. 2 FUEL OIL, AND ULTRA LOW SULFUR DIESEL.	EMERGENCY FIRE PUMP	DIESEL	350	HP		Methane	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	0		BACT-PSD	0	0		

Table B-1

CCS Cost Analysis - CO_2 Exhaust Flow Rates

Combustion Source	EPN	CO_2 Emissions[1]	CO_2 Emissions[2]
		ton/yr	MMScf/yr
Hot Oil Heater	003-SCR/VE	137,943.19	2,414.01
Amine Regenerator Heater	004-SCR/VE	23,501.43	411.28
MSS - Flare	004-FLARE	52.40	0.92
Thermal Oxidizer	002-THERMO	42,693.42	747.13
Total		204,190.45	3,573.33

[1]See Appendix A for CO_2 emission calculations.

[2]Volumetric emissions of CO_2 were calculated as follows:

CO_2 (tons/yr) * 2000 (lb/ton) / 44 (lb/lb-mole) * 385 (scf/lb-mole) / 10^6/MM

[3]Exhaust flow was calculated as follows:

Exhaust velocity (ft/sec) * 3600 (sec/hr) * PI * (Stack Dia (ft)/2)^2 * (459.67 + 68F) / (459.67 + exhaust temperature (F)) * 8760 (hr/yr) / 10^6/MM

Table B-2
CO_2 Pipeline Data

Pipeline Length (L)[1]	35	miles
Pipeline Diameter (D)[2]	8	inches
Number of Injection Wells	0	
Uncontrolled CO_2 Emissions	204,190.45	ton/year
	559.43	tons/day
Control Efficiency	90%	
Controlled CO_2 Emissions	20,419.05	ton/year
	55.94	ton/day

[1]Distance to pipeline is calculated approximately based on location of Denbury Green Pipeline location in Chambers County as seen from the National Pipeline Mapping System (http://www.npms.phmsa.dot.gov/)

[2] "Estimating Carbon Dioxide Transport and Storage Costs", National Energy Technology Laboratory, U.S. DOE, DOE/NETL - 2010/1447, March 2010, Figure 4

Table B-3
Estimated Costs for CCS of Stack CO_2 Emissions

Type	Units	Costs	
		Equation Used[3]	Cost $
Pipeline Costs			
Pipeline Materials	$ Diameter (inches), Length (miles)	$64,632 + $1.85 X L X (330.5 X D^2 + 686.7 X D + 26,960)	$3,535,594.60
Pipeline Labor	$ Diameter (inches), Length (miles)	$341,627 + $1.85 X L X (343.2 X D^2 + 2,074 X D + 170,013)	$13,846,521.55
Pipeline Miscellaneous	$ Diameter (inches), Length (miles)	$150,166 + $1.58 X L X (8,417 X D + 7,234)	$4,273,887.00
Pipeline Right of Way	$ Diameter (inches), Length (miles)	$48,037 + $1.20 X L X (577 X D + 29,788)	$1,493,005.00

Other Capital Costs			
Inlet Compression - one 3516 engine[3]	$		$2,500,000.00
CO_2 Compression Equipment - one 3516 engine[3]	$		$2,500,000.00
Cryogenic Units/Amine Units/Dehydrators[3]	$		$25,000,000.00
CO_2 Surge Tank[4]	$		$1,512,939.34
Pipeline Control System[4]	$		$145,466.95

Operation and Maintenance Costs[5]			
Fixed O&M	$/mile/year	$8,632	$302,120

		Total Cost	$55,109,534.44

Amortized Cost			
Total Capital Investment (TCI)	$		$54,807,414.44
Capital Recovery Factor (CRF)		$i\,(1 + i)^n/((1 + i)^n - 1)$ i = interest rate = 0.08 n = equipment life = 10 years	0.15
Amortized Cost	$	CRF X TCI	$8,167,920.95

Total Annualized Cost	$		$8,470,041
Cost Effectiveness	$/ton of CO_2 removed		$414.81

[3] Cost adjusted using average consumer price index to 2011 dollars from 2007 dollars based on data presented in "Estimating Carbon Dioxide Transport and Storage Costs", National Energy Technology Laboratory, U.S. DOE, DOE/NETL - 2010/1447, March 2010

[4] Estimated cost obtained from vendor

[5] "Estimating Carbon Dioxide Transport and Storage Costs", National Energy Technology Laboratory, U.S. DOE, DOE/NETL - 2010/1447, March 2010

TCEQ Permit Application Forms and Tables
Appendix C

December 2, 2011
Project No. 0140876

Environmental Resources Management
15810 Park Ten Place, Suite 300
Houston, Texas 77084
(281) 600-1000

TABLE 4
COMBUSTION UNITS

OPERATIONAL DATA				
Number from flow diagram: **012-THERMO**		Model Number(if available):		
Name of device: **Thermal Oxidizer**		Manufacturer		
CHARACTERISTICS OF INPUT				
Waste Material*	Chemical Composition			
Amine Unit	Material	Min. Value Expected (lb/hr)	Ave. Value Expected (lb/hr)	Design Maximum (lb/hr)
	1.			
	2.			
	3.			
	4.			
	5.			
Gross Heating Value of Waste Material (Wet basis if applicable)	Btu/lb **1020**	Air Supplied for Waste Material	Minimum	Maximum
Waste Material of Contaminated Gas	Total Flow Rate (lb/hr)		Inlet Temperature (°F)	
	Minimum Expected	Design Maximum	Minimum Expected	Design Maximum
Fuel	Chemical Composition			
	Material	Min. Value Expected (lb/hr)	Ave. Value Expected (lb/hr)	Design Maximum (lb/hr)
	1.			
	2.			
	3.			
	4.			
Gross Heating Value of Fuel	Btu/lb	Air Supplied for Fuel	Minimum SCFM (70°F & 14.7 psia)	Maximum SCFM(70°F & 14.7 psia)

*Describe how waste material is introduced into combustion unit on an attached sheet. Supply drawings, dimensioned and to scale to show clearly the design and operation of the unit.

US EPA ARCHIVE DOCUMENT

TABLE 4
COMBUSTION UNITS
(continued)

CHARACTERISTICS OF OUTPUT			
Flue Gas Released	Chemical Composition		
	Material	Min. Value Expected (lb/hr)	Ave. Value Expected (lb/hr)	Design Maximum (lb/hr)
	1. CO_2		50.8%	
	2. H_2O		0.0%	
	3. N_2		46.6%	
	4. SO_2		0.1%	
	5. O_2		2.47%	
Temperature at Stack Exit (°F)	Total Flow Rate (lb/hr)		Velocity at Stack Exit (ft/sec)	
	Minimum Expected	Maximum Expected	Minimum Expected	Maximum Expected

COMBUSTION UNIT CHARACTERISTICS		
Chamber Volume from Drawing (ft³)	Chamber Velocity at Average Chamber Temperature (ft/sec)	Average Chamber Temperature (°F)
Average Residence Time (sec)	Exhaust Stack Height (ft)	Exhaust Stack Diameter (ft)

ADDITIONAL INFORMATION FOR CATALYTIC COMBUSTION UNITS		
Number and Type of Catalyst Elements	Catalyst Bed Velocity (ft/sec)	Max. Flow Rate per Catalytic Unit (Manufacturer's Specifications) *Specify Units*

Attach separate sheets as necessary providing a description of the combustion unit, including details regarding principle of operation and the basis for calculating its efficiency. Supply an assembly drawing, dimensioned and to scale, to show clearly the design and operation of the equipment. If the device has by passes, safety valves, etc., specify when such bypasses are to be used and under what conditions. Submit explanations on control for temperature, air flow rates, fuel rates, and other operating variables.

10/93

Table 6

BOILERS AND HEATERS

Type of Device:	Hot Oil Heater	Manufacturer:	
Number from flow diagram: (EPN 013-SCR/VE)		Model Number:	

CHARACTERISTICS OF INPUT

Type Fuel	Chemical Composition (% by Weight)		Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
				Average	Design Maximum
				3,700	240 MMBtu/hr
Natural Gas			Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
			(specify units)	Average	Design Maximum
			1,020 Btu/scf	____scfm*	____scfm*
				____% excess	____% excess
				(vol)	(vol)

HEAT TRANSFER MEDIUM

Type Transfer Medium (Water, oil, etc.)	Temperature °F		Pressure (psia)		Flow Rate (specify units)	
	Input	Output	Input	Output	Average	Design Maximum
Oil						

OPERATING CHARACTERISTICS

Average Fire Box Temp. at max. firing rate	Fire Box Volume (ft.³) (from drawing)	Gas Velocity in Fire Box (ft/sec) at max firing rate	Residence Time in Fire Box at max firing rate (sec)

STACK PARAMETERS

Stack Diameters	Stack Height	Stack Gas Velocity (ft/sec)		Stack Gas	Exhaust
		(@Ave. Flow Rate)	(@Max.Flow Rate)	Temp °F	scfm
7.6 ft	100	44.1		555	

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Volume)
	See Table 1(a)

Attach an explanation on how temperature, ari flow rate, excess air or other operating variables are controlled.

Also supply an assembly drawing, dimensioned and to scale, in plane, elevation, and as many sections as are needed to show clearly the operation of the combustion unit. Show interior dimensions and features of the equipment necessary to calculate in performance.

*Standard Conditions: 70°F, 14.7 psia

Table 6

BOILERS AND HEATERS

Type of Device:	Molecular Sieve Regenerator Heater	Manufacturer:
Number from flow diagram: (EPN 013-SCR/VE)		Model Number:

CHARACTERISTICS OF INPUT

Type Fuel	Chemical Composition (% by Weight)		Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
				Average	Design Maximum
				3,700	34 MMBtu/hr
Natural Gas			Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
			(specify units)	Average	Design Maximum
			1,020 BTU/scf	____scfm*	____scfm*
				____% excess	____% excess
				(vol)	(vol)

HEAT TRANSFER MEDIUM

Type Transfer Medium	Temperature °F		Pressure (psia)		Flow Rate (specify units)	
(Water, oil, etc.)	Input	Output	Input	Output	Average	Design Maximum
N/A						

OPERATING CHARACTERISTICS

Average Fire Box Temp. at max. firing rate	Fire Box Volume (ft.³) (from drawing)	Gas Velocity in Fire Box (ft/sec) at max firing rate	Residence Time in Fire Box at max firing rate (sec)

STACK PARAMETERS

Stack Diameters	Stack Height	Stack Gas Velocity (ft/sec)		Stack Gas	Exhaust
		(@Ave. Flow Rate)	(@Max.Flow Rate)	Temp °F	scfm
7.6 ft	100	44.1		555	

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Volume)
	See Table 1(a)

Attach an explanation on how temperature, ari flow rate, excess air or other operating variables are controlled.

Also supply an assembly drawing, dimensioned and to scale, in plane, elevation, and as many sections as are needed to show clearly the operation of the combustion unit. Show interior dimensions and features of the equipment necessary to calculate in performance.

*Standard Conditions: 70°F, 14.7 psia

Table 8
FLARE SYSTEMS

Number from Flow Diagram: 004-FLARE			Manufacturer & Model No. (if available):			
CHARACTERISTICS OF INPUT						
Waste Gas Stream	Material	Min. Value Expected	Ave. Value Expected		Design Max.	
		(scfm [68°, 14.7 psia])	(scfm [68°, 14.7 psia])		(scfm [68°, 14.7 psia])	
MSS Emissions			25			
% of time this condition occurs		0.27%				
		Flow Rate (scfm [68°, 14.7 psia])			Temp. °F	Pressure (psig)
		Minimum Expected	Design Max.			
Waste Gas Streams						
Fuel Added to Gas Streams						
	Number of Pilots		Type Fuel	Fuel Flow Rate (scfm [70°, 14.7 psia]) per pilot		
	1		Natural Gas	200 scfh		
For Stream injection	Stream Pressure (psig)		Total Stream Flow		Temp. °F	Velocity (ft/sec)
	Minimum Expected	Design Max.	Rate (lb/hr)			
	Number of Jet Streams		Diameter of Steam Jets (inches)	Design basis for steam injected (lb steam/lb hydrocarbon)		
For Water Injection	Water Pressure (psig) Min. Expected Design Max.		Total Water Flow Rate (gpm) Min. Expected Design Max.	No. of Water Jets	Diameter of Water Jets (inches)	
Flare Height (ft)	415		Flare tip inside diameter (ft)			
Capital Installed Cost $ _____			Annual Operation Cost $_____			

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

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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.

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

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

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
ERM
3029 S. Sherwood Forest Blvd, Ste. 300
Baton Rouge, LA 70816

direct: (225) 368-2020
fax: (225) 292-3011
cell: (713) 689-4572
james.smith@erm.com
www.erm.com

Energy Transfer Partners, L.P. dba Lone Star NGL, LLC
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ADDENDUM 1

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Energy Transfer Partners, L.P. dba Lone Star NGL, LLC
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ADDENDUM 2

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<u>BACT for As Built FRAC I Sources</u>
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.

<u>Additional Impacts</u>
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,

James Smith
ERM
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Baton Rouge, LA 70816

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cell: (713) 689-4572
james.smith@erm.com
www.erm.com

Energy Transfer Partners, L.P. dba Lone Star NGL, LLC
Greenhouse Gas PSD Permit Application
Response to EPA's Questions dated March 29, April 3, and April 4, 2012

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

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.

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[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.

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

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).

Amortized Project Costs (without carbon capture and sequestration)
(April 21, 2012)

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

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.
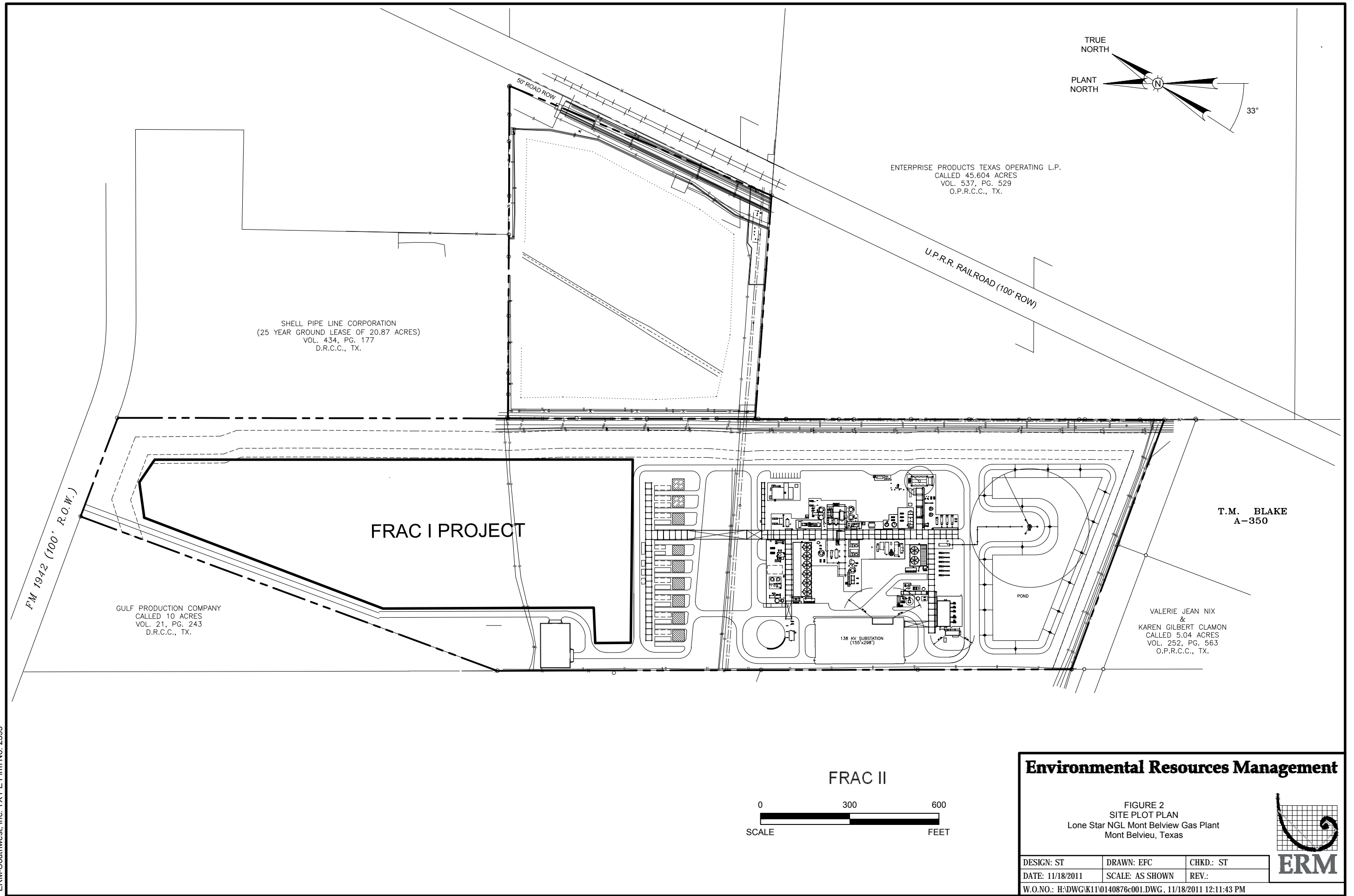CCS equipment is expected to have a life of 10 years due to extreme acidic nature of CO2.

TRUE
NORTH

PLANT
NORTH

N

33°

ENTERPRISE PRODUCTS TEXAS OPERATING L.P.
CALLED 45.604 ACRES
VOL. 537, PG. 529
O.P.R.C.C., TX.

50' ROAD ROW

U.P.R.R. RAILROAD (100' ROW)

SHELL PIPE LINE CORPORATION
(25 YEAR GROUND LEASE OF 20.87 ACRES)
VOL. 434, PG. 177
D.R.C.C., TX.

FM 1942 (100' R.O.W.)

FRAC I PROJECT

T.M. BLAKE
A-350

POND

GULF PRODUCTION COMPANY
CALLED 10 ACRES
VOL. 21, PG. 243
D.R.C.C., TX.

138 KV SUBSTATION
(155'x298')

VALERIE JEAN NIX
&
KAREN GILBERT CLAMON
CALLED 5.04 ACRES
VOL. 252, PG. 563
O.P.R.C.C., TX.

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

FRAC II

0	300	600

SCALE   FEET

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		

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	👍

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	👍

US EPA ARCHIVE DOCUMENT

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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 - 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	👍

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.	

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			

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 Industr*y, 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.

[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.

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.

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

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

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]	CO₂ 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.

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