12770 Merit Drive | Suite 900 | Dallas, TX 75251 | P (972) 661-8100 | F (972) 385-9203
trinityconsultants.com

Trinity Consultants

March 20, 2012

Mr. Jeff Robinson
Permit Section Chief
U.S. Environmental Protection Agency, (6PD-R)
1445 Ross Ave
Dallas, TX 75202-2733

RE: Application for Prevention of Significant Deterioration for Greenhouse Gas Emissions
Targa Midstream Services LLC – Mont Belvieu Plant Train 5

Dear Mr. Robinson:

Targa Midstream Services LLC (Targa) operates a natural gas fractionating plant in Mont Belvieu, Chambers County, Texas (Mont Belvieu Plant). The Mont Belvieu Plant is designed to fractionate natural gas liquids into various products and to remove sulfur compounds from high sulfur natural gasoline. The Mont Belvieu Plant is considered an existing major source with respect to the Prevent of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) permitting programs.

Targa is proposing to construct a new fractionation train (Train 5) at the facility. The proposed Train 5 project will be a major modification with respect to greenhouse gas (GHG) emissions and subject to PSD permitting requirements under the GHG Tailoring Rule. With a final action published in May 2011, EPA promulgated a Federal Implementation Plan (FIP) to implement the permitting requirements for GHGs in Texas, and EPA assumed the role of permitting authority for Texas GHG permit applications with that action. Therefore, GHG emissions from the proposed Train 5 project are subject to the jurisdiction of the EPA under authority EPA has asserted in Texas through its FIP for the regulation of GHGs. As shown in the enclosed permit application, the proposed Train 5 project will be a minor modification with respect to all non-GHG pollutants. TCEQ remains the permitting authority for all such pollutants, and all non-GHG pollutants from the proposed project are subject to the jurisdiction of the TCEQ for minor source state NSR permitting. Accordingly, Targa is submitting applications to both EPA and TCEQ to obtain the requisite authorizations to construct. The minor source state NSR permit application for non-GHG pollutants submitted to TCEQ is included as an appendix of this GHG PSD permit application for reference.

The enclosed permit application is prepared in accordance with EPA guidance. This application includes a TCEQ Form PI-1, other applicable forms, a Best Available Control Technology evaluation, emission calculations, process description and flow diagram, and supporting documentation.

If you have any questions or comments about the information presented in this letter, please do not hesitate to call Ms. Melanie Roberts, Targa, at (713) 584-1422.

Sincerely,

TRINITY CONSULTANTS

Jessica Coleman

Jessica Coleman
Senior Consultant

Enclosure

cc: Air Section Manager, TCEQ Region 12
Mr. Hunter Battle, Vice President Logistics and Marketing Assets, Targa
Ms. Jessica Keiser, Assistant VP ES&H, Targa
Ms. Melanie Roberts, Environmental Manager, Targa
Ms. Melissa Dakas, Managing Consultant, Trinity Consultants

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT APPLICATION FOR GREENHOUSE GASES

Targa Midstream Services LLC > Mont Belvieu Plant Train 5

Prepared By:

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March 2012

Project 114401.0169

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1. EXECUTIVE SUMMARY

Targa Midstream Services LLC (Targa) operates a natural gas liquids (NGL) fractionator called the Mont Belvieu Plant in Mont Belvieu, Chambers County, Texas. The site is designed to fractionate NGLs into specification NGL components (ethane, propane, iso-butane, normal-butane and natural gasoline). A portion of the natural gasoline produced is further processed to remove contained sulfur compounds and to saturate contained benzene. In addition to the fractionation system, gas dehydrating units and hydrotreating systems, other sources of air emissions include flares (process and back-up), fugitives and utility systems (boilers for steam production, fire water pumps, and emergency generator pumps).

The Mont Belvieu Plant is considered an existing major source with respect to the Prevent of Significant Deterioration (PSD) permitting program. Targa is proposing to construct a new fractionation train (Train 5) at the facility, which will be operated independent of existing operations at the facility. Installation of the proposed fractionation train will not be a major modification with respect to any criteria pollutant. The proposed project will be a major modification with respect to Greenhouse Gas (GHG) emissions. Targa is submitting this PSD permit application to authorize GHG emissions from the proposed fractionation train.

The Mont Belvieu Plant operates under Texas Commission on Environmental Quality (TCEQ) Air Quality Account Number CI-0022-A. Targa has been assigned TCEQ Customer Reference Number (CN) 601301559, and the Mont Belvieu Plant has been assigned Regulated Entity Reference Number (RN) 100222900. The existing emission sources at the Mont Belvieu Plant are currently authorized under new source review (NSR) permits, various Standard Exemptions, Permits by Rule (PBRs), and Standard Permits.

1.1. PROPOSED PROJECT

Targa is proposing to build a new fractionation train at the Mont Belvieu Plant. The proposed project includes the following equipment:

- Fractionation train and ancillary equipment
- Amine unit
- Tri-ethylene glycol (TEG) dehydration unit
- Cooling tower
- Hot oil heaters (2)
- Fugitives
- Atmospheric storage tanks

1.2. PERMITTING CONSIDERATIONS

The Mont Belvieu Plant is an existing major source with respect to GHG emissions under the PSD program because the site currently has a potential to emit greater than 100,000 tons per year (tpy) of carbon dioxide equivalent (CO_2e). The proposed project will be a major modification with respect to GHG emissions and subject to PSD permitting requirements as the U.S. Environmental Protection Agency (EPA) has interpreted them in the GHG Tailoring Rule.[1] In the Tailoring Rule, EPA established a major source threshold of 100,000 tpy CO_2e for new GHG sources and a major modification threshold of 75,000 tpy CO_2e for existing major sources. Targa has determined that the net increase of GHG emissions from the proposed project will exceed 75,000 tpy as shown in Section 7 of this permit application. As a result, Targa has concluded that the proposed project will be a major modification with respect to GHGs.

[1] Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, 75 Fed. Reg. 31,514 (June 3, 2010).

The combined potential to emit GHGs from the Train 5 project will be greater than 75,000 tpy on a CO_2e basis primarily due to emissions from the hot oil heaters and the amine unit vent that is routed through the flare. In addition, the TEG unit, maintenance, startup, and shutdown (MSS) activities, and fugitives from piping components will be sources of GHG emissions. A summary of the GHG emissions from the proposed project, calculated on a CO_2e basis by use of the Global Warming Potentials (GWP) set forth in Table A-1 to Subpart A of Title 40 of the Code of Federal Regulations (40 CFR) Part 98, is shown in Table 1-1 below. Detailed emission calculations are provided in Section 7 of this application.

Table 1-1. Proposed Project GHG Emissions

Source	Annual Emissions (tpy)			
	CO_2	CH_4	N_2O	CO_2e
F5A	73,954	1.39	0.14	74,026
F5B	73,954	1.39	0.14	74,026
FLR-5 [a]	17,595	0.20	0.05	17,615
FUG-FRAC5	0.01	0.11	0	2.33
Uncontrolled MSS Emissions to Atmosphere	0	0.08	0	1.69
Total Project Emissions	165,503	3.18	0.33	165,672

[a] GHG emissions from the TEG Unit and the Amine Unit as well as controlled MSS activities and pilot and supplemental fuel usage are accounted for in FLR-5.

With a final action published in May 2011, EPA promulgated a Federal Implementation Plan (FIP) to implement the permitting requirements for GHGs in Texas, and EPA assumed the role of permitting authority for Texas GHG permit applications with that action.[2] Therefore, GHG emissions from the proposed project are subject to the jurisdiction of the EPA under authority EPA has asserted in Texas through its FIP for the regulation of GHGs. TCEQ remains the permitting authority for all criteria pollutants.

As shown in Section 9 of this permit application, the proposed project will be a minor modification with respect to all non-GHG pollutants. Therefore, all non-GHG emissions from the proposed project are subject to the jurisdiction of the TCEQ for minor source state NSR permitting. Accordingly, Targa is submitting applications to both EPA and TCEQ to obtain the requisite authorizations to construct. The state minor NSR permit application submitted to TCEQ is included in Appendix E of this GHG PSD permit application for reference.

1.3. PERMIT APPLICATION

All required supporting documentation for the permit application is provided in the following sections. The TCEQ Form PI-1 is included in Section 2 of this application. An area map indicating the site location and a plot plan identifying the location of various emission units at the site are included in Sections 3 and 4 of the report, respectively. A project description and process flow diagram are presented in Sections 5 and 6, respectively. Emission calculations can be found in Section 7 of this application.

Detailed federal NSR requirements relating to the project are provided in Section 9. Discussions of Best Available Control Technology (BACT) are provided in Sections 10 and 11. The analyses related to the Endangered Species Act and National Historic Preservation Act will be addressed in separate filings.

---

[2] Determinations Concerning Need for Error Correction, Partial Approval and Partial Disapproval, and Federal Implementation Plan Regarding Texas's Prevention of Significant Deterioration Program, 76 Fed. Reg. 25,178 (May 3, 2011).

2. TCEQ FORM PI-1

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: Targa Midstream Services LLC		
Texas Secretary of State Charter/Registration Number (*if applicable*):		
B. Company Official Contact Name: Hunter Battle		
Title: Vice President Logistics and Marketing Assets		
Mailing Address: 1000 Louisiana Street, Suite 4300		
City: Houston	State: TX	ZIP Code: 77002
Telephone No.: 713-584-1443	Fax No.:	E-mail Address:
C. Technical Contact Name: Dena Taylor		
Title: Sr. Environmental Specialist		
Company Name: Targa Midstream Services LLC		
Mailing Address: 10319 Highway 146		
City: Mont Belvieu	State: TX	ZIP Code: 77523
Telephone No.: 281-385-3165	Fax No.: 281-385-3187	E-mail Address: dtaylor@targaresources.com
D. Site Name: Mont Belvieu Fractionator		
E. Area Name/Type of Facility: Natural Gas Liquids Extraction and Processing		☒ Permanent ☐ Portable
F. Principal Company Product or Business: Natural Gas Liquids		
Principal Standard Industrial Classification Code (SIC): 1321		
Principal North American Industry Classification System (NAICS):		
G. Projected Start of Construction Date: 3/1/2013		
Projected Start of Operation Date: 7/1/2013		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: 10319 Highway 146		
City/Town: Mont Belvieu	County: Chambers	ZIP Code: 77523
Latitude (nearest second): 29:50:31	Longitude (nearest second): 94:53:44	

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): CI-0022-A	
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): CN601301559	
L. Regulated Entity Number (RN): RN100222900	
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: 22	
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: Craig Eiland	District No.: 23
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):	
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:__________	
D. Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c).	☐ YES ☒ NO

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

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.): O-612		
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 ☐		

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). Louisiana	
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*): **Please see Emission Data Section in Report**	
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):	
Hazardous Air Pollutants (HAPs):	
Other speciated air contaminants **not** listed above:	

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: Dena Taylor			
Title: Sr. Environmental Specialist			
Mailing Address: 10319 Highway 146			
City: Mont Belvieu	State: TX	ZIP Code: 77523	
B. Name of the Public Place: West Chambers Branch Library			
Physical Address (No P.O. Boxes): 10616 Eagle Drive			
City: Mont Belvieu	County: Chambers	ZIP Code: 77680	
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: Jimmy Sylvia			
Mailing Address: P.O. Box 939			
City: Anahuac	State: TX	ZIP Code: 77514	
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: Mayor Nick Dixon			
Mailing Address: P.O. Box 1048			
City: Mont Belvieu	State: TX	ZIP Code: 77580	
Name of the Federal Land Manager:			
Title:			
Mailing Address:			
City:	State:	ZIP Code:	

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? Spanish	
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 ☒	

VII. Technical Information			
B. Are any schools located within 3,000 feet of this facility?			☐ YES ☒ NO
C. Maximum Operating Schedule:			
Hours: 24 hr/day	Day(s): 7 day/wk	Week(s): 52 wk/yr	Year(s): 8,760 hr/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

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: 551474		Fee Amount: $75,000
Company name on check: Targa Resources Partners LP		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

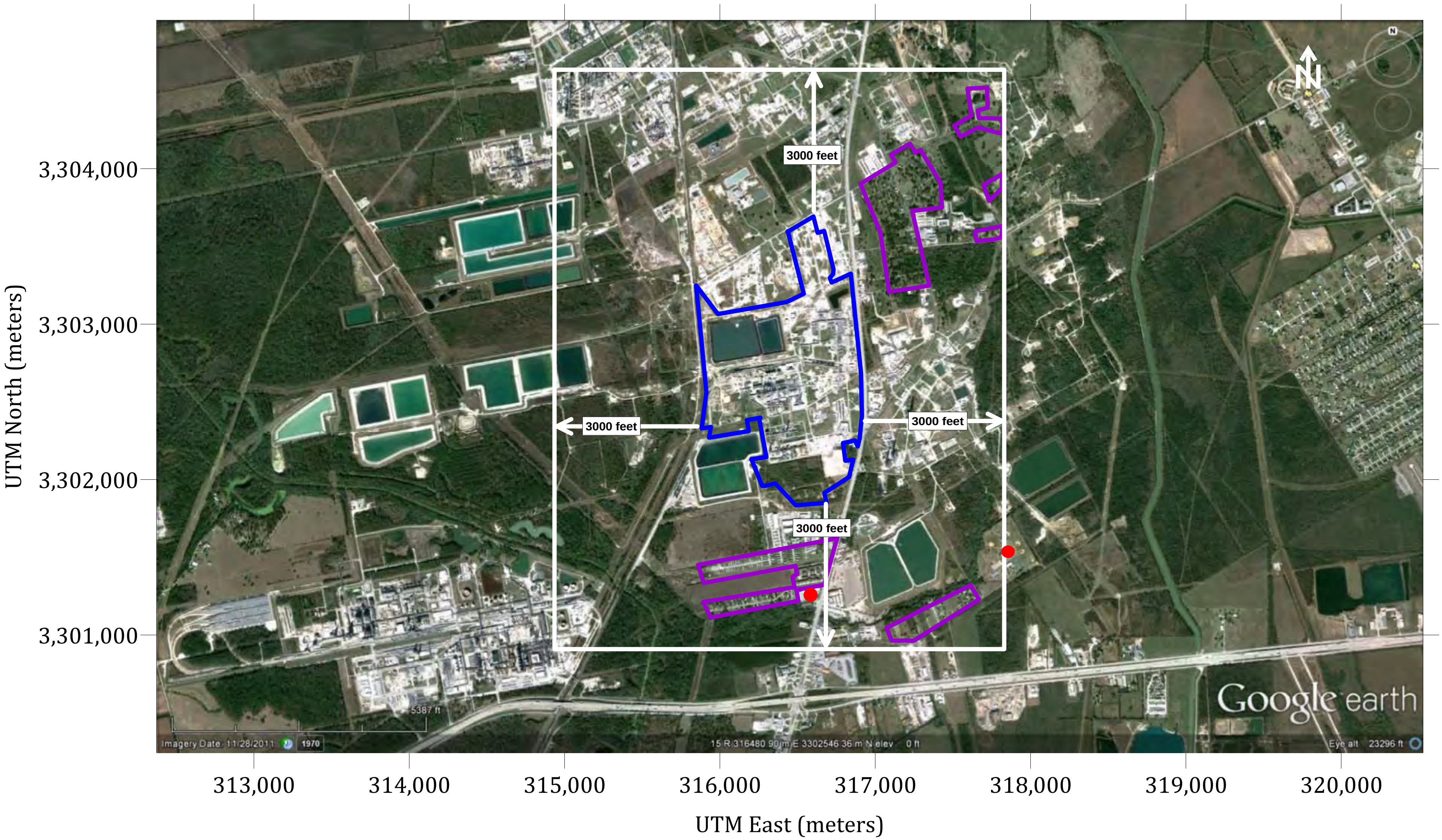
Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

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: Hunter Battle
Signature: Hunter Battle *Original Signature Required*
Date: March 19, 2012

3. AREA MAP

The Mont Belvieu Plant is located in Chambers County, Texas. An area map is included in this section to graphically depict the location of the facility with respect to the surrounding topography. Figure 3-1 is an area map centered on the Mont Belvieu Plant that extends out at least 3,000 feet from the property line in all directions. The map depicts the fenceline/property line with respect to predominant geographic features (such as highways, roads, streams, and railroads). There are no schools within 3,000 feet of the facility boundary.

Figure 3-1.
Targa Midstream Services LLC
Mont Belvieu Area Map



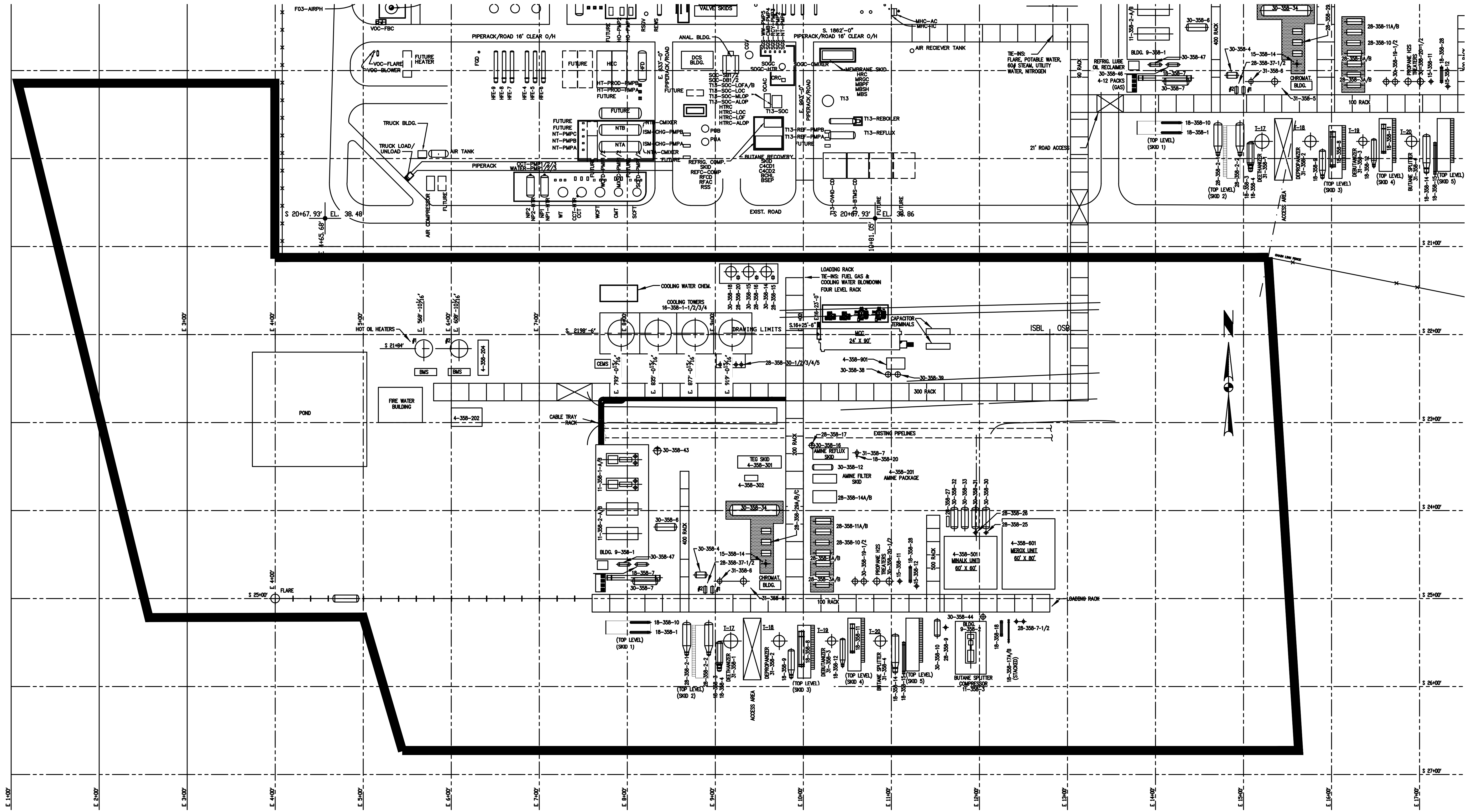
Legend

- Property Line
- Residential Areas
- Sensitive Receptors - Places of Worship

Reference UTM Coordinates are in NAD83.
Map image from Google Earth TM Mapping Service.

4. PLOT PLAN

The following figure depicts the site plans for the proposed Mont Belvieu Plant.



PIPERACK/ROAD 16' CLEAR O/H
S. 1862'-0"
VOC-FBC
VOC-FLARE
VOC-BLOWER
FUTURE HEATER
ANAL. BLDG.
DCS BLDG.
VALVE SKIDS
AIR RECIEVER TANK
MEMBRANE SKID
TRUCK BLDG.
TRUCK LOAD/ UNLOAD
AIR TANK
PIPERACK
AIR COMPRESSOR
REFRIG. COMP. SKID
BUTANE RECOVERY
EXIST. ROAD
TIE-INS: FLARE, POTABLE WATER, 60# STEAM, UTILITY WATER, NITROGEN
REFRIG. LUBE OIL RECLAIMER
21' ROAD ACCESS
100 RACK
400 RACK
S 20+67.93'
EL. 38.48
S 21+00'
S 22+00'
S 23+00'
S 24+00'
S 25+00'
S 26+00'
S 27+00'
COOLING WATER CHEM.
COOLING TOWERS 16-358-1-1/2/3/4
DRAWING LIMITS
LOADING RACK
TIE-INS: FUEL GAS & COOLING WATER BLOWDOWN
FOUR LEVEL RACK
MCC 24' X 90'
CAPACITOR TERMINALS
ISBL
OSB
HOT OIL HEATERS
S 21+84'
BMS
CEMS
POND
FIRE WATER BUILDING
4-358-202
4-358-204
CABLE TRAY RACK
300 RACK
200 RACK
EXISTING PIPELINES
AMINE REFLUX SKID
AMINE FILTER SKID
4-358-201 AMINE PACKAGE
TEG SKID 4-358-301
4-358-302
BLDG. 9-358-1
CHROMAT. BLDG.
500 RACK
4-358-501 MINALK UNIT 60' X 60'
4-358-601 MEROX UNIT 60' X 80'
PROPANE H2S TREATERS
FLARE
S 25+00'
GRADING RACK
(TOP LEVEL) (SKID 1)
(TOP LEVEL) (SKID 2)
(TOP LEVEL) (SKID 3)
(TOP LEVEL) (SKID 4)
(TOP LEVEL) (SKID 5)
DEETHANIZER 31-358-1
DEPROPANIZER 31-358-2
DEBUTANIZER 31-358-3
BUTANE SPLITTER 31-358-4
ACCESS AREA
BUTANE SPLITTER COMPRESSOR 11-358-3
18-358-17A/B (STACKED)
E 1+00'
E 2+00'
E 3+00'
E 4+00'
E 5+00'
E 6+00'
E 7+00'
E 8+00'
E 9+00'
E 10+00'
E 11+00'
E 12+00'
E 13+00'
E 14+00'
E 15+00'
E 16+00'
E 17+00'

5. PROJECT DESCRIPTION

The Mont Belvieu Fractionator, a process unit at Mont Belvieu Plant, is designed to fractionate natural gas liquids into various products. With this project, Targa plans to build a new fractionation train (Train 5). The feed consists of mixed NGLs; which is a mixture of ethane, propane, butane, heavier hydrocarbons, CO_2, and small amounts of hydrogen sulfide (H_2S). The feed is first sent to the deethanizer to separate ethane. The overhead off the deethanizer will be treated in the amine unit to remove the non-hydrocarbon gases (CO_2 and H_2S). Then water is removed from the ethane in the TEG dehydration unit. The heavier fraction from the deethanizer is fed to the depropanizer to separate the propane product. The heavier fraction of the depropanizer is further fed to the debutanizer to separate the mixed butane product from natural gasoline. The butane product is then sent through the deisobutanizer to separate normal and iso-butane. All the specification NGL products are transported from the fractionation plant by pipelines. Supporting utility operations include the installation of two new hot oil heaters and a cooling tower for heating and cooling of the process, respectively.

The following subsections further describe the processes, equipment, and the proposed emission sources included in the Train 5 Project. Of the proposed sources, the amine unit, TEG dehydration unit, hot oil heaters, and fugitive emissions from piping components will emit GHGs. A process flow diagram showing the new sources is included in Section 6.

5.1. AMINE UNIT

Amine Unit 4 (Facility Identification Number [FIN] AU-4) includes an absorber, regenerator, and flash drum. In the absorber, an amine solution absorbs CO_2 and H_2S from a fractionated ethane gas stream to produce a treated ethane gas stream with lower CO_2 content and no H_2S. These non-hydrocarbon contaminants (CO_2 and H_2S) are in solution with the rich amine solution. The rich amine is then routed to a regenerator that separates the non-hydrocarbon contaminants from the amine solution to produce regenerated (lean) amine that can be reused in the absorber. Emissions from the regenerator and flash drum are routed to the flare (Emission Point Number [EPN] FLR-5). Treated gas is sent to a new TEG dehydration unit for removal of moisture/water.

5.2. TEG DEHYDRATION UNIT

The TEG Dehydration Unit (FIN TEG-2) uses TEG to remove water or water vapor present in the ethane gas stream and includes a flash tank. Emissions from the glycol unit regenerator and flash tank are routed to the flare (EPN FLR-5).

5.3. HOT OIL HEATERS

Two new hot oil heaters are required as part of this project. The heaters (EPNs F5A and F5B) are natural gas-fired heaters with a higher heating value (HHV) design capacity of 144.45 million British thermal units per hour (MMBtu/hr) each. The new heaters are equipped with low-NO_x burners and selective catalytic reduction (SCR) systems.

5.4. COOLING TOWER

A new cooling tower is required to provide for the fractionation process cooling. Cooling Tower 9 (EPN FUG-CT-9) is a mechanically induced draft, counterflow cooling tower. The cooling tower is designed to recirculate 44,322 gallons per minute (gpm) water. Based on the composition of the recirculation water for the cooling tower (i.e., little to no methane entrained in the water), GHG emissions from this unit are determined to be negligible and are not included in this permit application.

5.5. FUGITIVE COMPONENTS

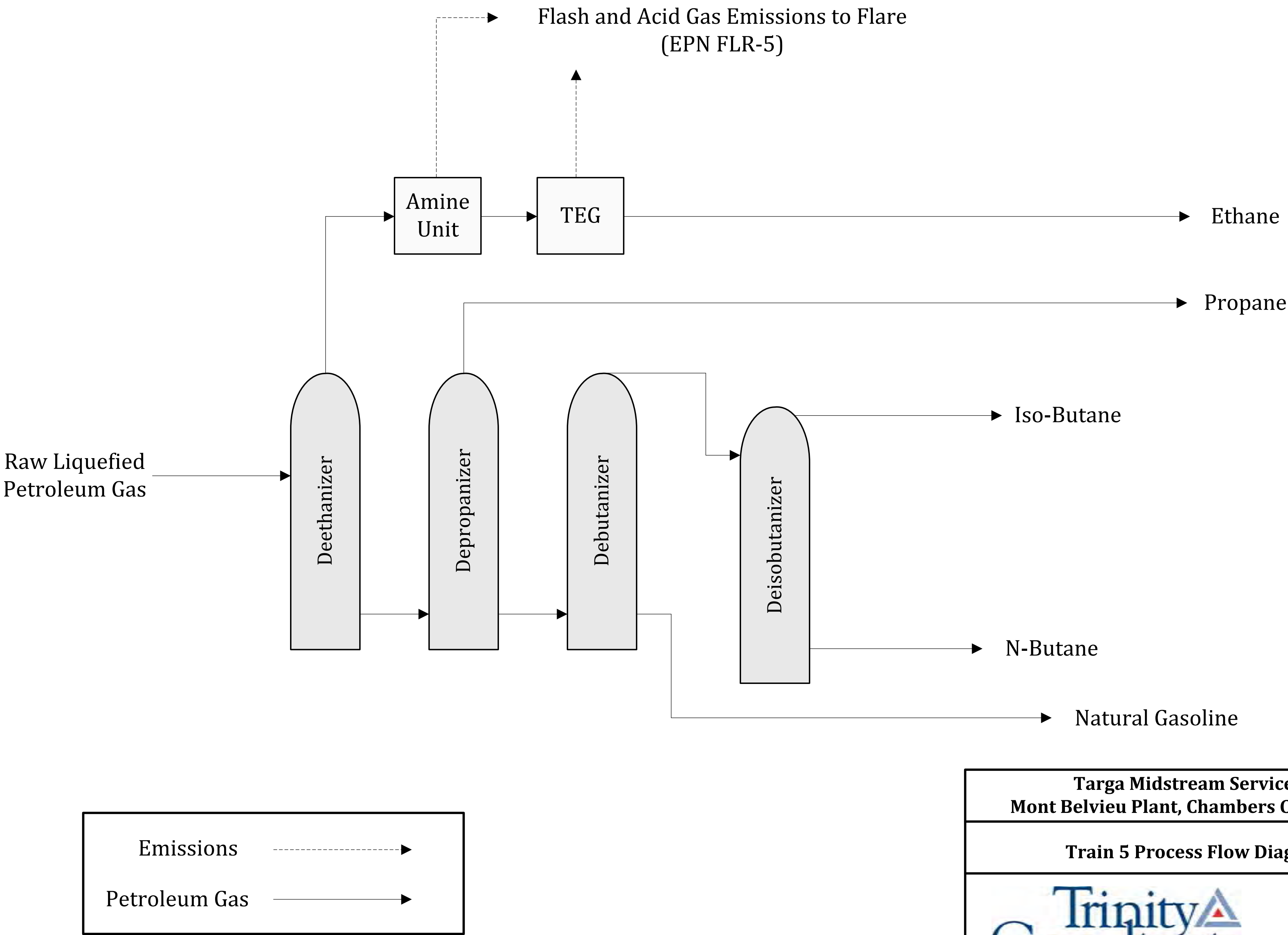
New fugitive emissions (EPN FUG-FRAC5) from piping and equipment associated with the proposed project are accounted for via the number of valves, flanges, and other connections.

5.6. ATMOSPHERIC STORAGE TANKS

A series of small atmospheric storage tanks will be added with this project. Based on the low vapor pressure, low throughput, and/or the contents of these tanks, GHG emissions from these units are determined to be negligible and are not included in this permit application.

6. PROCESS FLOW DIAGRAM

Figure 6.1 - Train 5 Process Flow Diagram



Targa Midstream Services LLC   **Mont Belvieu Plant, Chambers County, Texas**
Train 5 Process Flow Diagram
Trinity Consultants **March 2012**   **114401.0169**

This section summarizes the GHG emission calculation methodologies and provides emission calculations for the proposed GHG emission sources included in the Train 5 project. Detailed emission calculation spreadsheets, including example calculations, are included at the end of this section. These emission rates reflect the emission limits chosen as BACT in Section 11.

The following sources of GHG emissions are included in the emission calculations provided at the end of this section:

- Amine unit (FIN AU-4, EPN FLR-5);
- TEG dehydration unit (FIN TEG-2, EPN FLR-5);
- Hot oil heaters (EPNs F5A and F5B);
- Fugitive emissions from piping components (EPN FUG-FRAC5);
- Maintenance emissions to the flare (FIN Maintenance, EPN FLR-5);
- Startup emissions to the flare (FIN Startup, EPN FLR-5);
- Shutdown emissions to the flare (FIN Shutdown, EPN FLR-5);
- Maintenance emissions to the atmosphere (FIN Maintenance, EPN Maintenance); and
- Shutdown emissions to the atmosphere (FIN Shutdown, EPN Shutdown).

The operation of these sources will result in emissions of CO_2, methane (CH_4), and nitrous oxide (N_2O).

Targa is also proposing to construct several small atmospheric storage tanks and a cooling tower (EPN FUG-CT-9). However, based on the low vapor pressure, low throughput, and contents of the tanks and the composition of the recirculation water in the cooling tower, GHG emissions have been determined to be negligible and emission estimates for operation of these units are not included in this GHG PSD permit application.

According to 40 CFR Section (§)52.21(b)(49)(ii), PSD applicability for GHG emissions are determined based on GHG emissions on a carbon dioxide equivalent basis (CO_2e), as calculated by multiplying the mass of each of the six regulated GHGs by the gas's associated GWP.[3] The GWP for each GHG proposed to be emitted from the Train 5 Project is listed in the following table.

Table 7-1. Greenhouse Gas Global Warming Potentials

CO_2	CH_4	N_2O
1	21	310

The following is an example calculation for hourly and annual CO_2e emissions:

$$\text{CO}_2\text{e Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{CO}_2\text{ Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right)\times\text{CO}_2\text{ GWP} + \text{CH}_4\text{ Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right)\times\text{CH}_4\text{ GWP} + \text{N}_2\text{O Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right)\times\text{N}_2\text{O GWP}$$

[3] 40 CFR Part 98, Subpart A, Table A-1.

$$CO_2e \text{ Annual Emission Rate (tpy)} = CO_2 \text{ Annual Emission Rate (tpy)} \times CO_2 \text{ GWP} + CH_4 \text{ Annual Emission Rate (tpy)} \times CH_4 \text{ GWP} + N_2O \text{ Annual Emission Rate (tpy)} \times N_2O \text{ GWP}$$

Emissions of CO_2, CH_4, and N_2O are estimated using the methodologies outlined in EPA's Mandatory Greenhouse Gas Reporting Rule (40 CFR Part 98) or a mass balance approach, as detailed in the remainder of this section.

7.1. HOT OIL HEATERS

The Train 5 Project will include two natural gas-fired hot oil heaters (EPNs F5A and F5B). Combustion of natural gas will result in emissions of CO_2, CH_4, and N_2O.

GHG emissions are estimated based on proposed equipment specifications as provided by the manufacturer and the default emission factors in 40 CFR Part 98 Subpart C for stationary fuel combustion sources and as shown in the following table. [4]

Table 7.1-1. Natural Gas Combustion GHG Emission Factors

Units	CO_2	CH_4	N_2O
kg/MMBtu	53.02	1.0E-03	1.0E-04
lb/MMBtu *	116.89	2.20E-03	2.2E-04

*Emission factors are converted from kilograms to pounds using the conversion factor 2.2046 lb/kg.

Hourly emission rates for CO_2, CH_4, and N_2O are based on the heat input rating (MMBtu/hr) for the heaters. Annual emission rates are based on maximum operation equivalent to 8,760 hrs/yr. The following equations are used to estimate hourly and annual CO_2, CH_4, and N_2O emission rates from the heaters:

$$\text{Hourly Emission Rate} \left(\frac{\text{lb}}{\text{hr}}\right) = \text{Heat Input Rating} \left(\frac{\text{MMBtu}}{\text{hr}}\right) \times \text{Emission Factor} \left(\frac{\text{lb}}{\text{MMBtu}}\right)$$

$$\text{Annual Emission Rate (tpy)} = \text{Hourly Emission Rate} \left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Hours of Operation} \left(\frac{\text{hr}}{\text{yr}}\right) \times \left(\frac{\text{ton}}{2{,}000 \text{ lb}}\right)$$

7.2. FLARE

The flare (EPN FLR-5) will be used to control emissions from the amine unit and TEG dehydration unit. Emissions of CO_2, CH_4, and N_2O from the flare will result from the combustion of pipeline quality natural gas in the pilot, the combustion of supplemental fuel, the combustion of process gas from the amine unit and TEG dehydration unit, and the combustion of process gas sent to the flare during MSS events.

Emissions from pilot gas and supplemental fuel combustion are estimated using the methodologies described below, the design pilot gas flow rate, and the natural gas fuel analysis.

[4] 40 CFR Subpart C, Tables C-1 and C-2.

GHG emissions from combustion of amine unit and dehydrator process gas and MSS event process gas are estimated based on methodologies in 40 CFR Part 98 Subpart W for petroleum and natural gas systems.

Pilot Gas and Supplemental Fuel Emissions

Hourly emission rates for CO_2, CH_4, and N_2O are based on the heat input rating (MMBtu/hr) for the pilot flare and estimated supplement fuel heat input rating requirements (MMBtu/hr) to maintain heat content of waste gas greater than 300 Btu/scf as required for compliance with 40 CFR §60.18. 40 CFR Part 98 Subpart W refers to Subpart C for emission factors for estimating GHG emissions from the combustion of natural gas in a flare. The emission factors used are shown in Table 7.1-1. Annual emission rates are based on maximum operation equivalent to 8,760 hrs/yr. The following equations are used to estimate hourly and annual emission rates from the pilot flare:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Heat Input Rating}\left(\frac{\text{MMBtu}}{\text{hr}}\right) \times \text{Emission Factor}\left(\frac{\text{lb}}{\text{MMBtu}}\right)$$

$$\text{Annual Emission Rate (tpy)} = \text{Controlled Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Hours of Operation}\left(\frac{\text{hr}}{\text{yr}}\right) \times \left(\frac{\text{ton}}{2{,}000\text{ lb}}\right)$$

Amine Unit and TEG Dehydration Unit Emissions

Controlled hourly emission rates for CO_2 and CH_4 from the flare are estimated using the inlet to flare data based on similar operations at the facility and GLYCalc outputs for the amine and dehydrator waste streams, respectively, and the guaranteed destruction efficiency.

The following equation is used to estimate hourly CO_2 and CH_4 emission rates from the controlled streams:

$$\text{Controlled Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Inlet to Flare}\left(\frac{\text{lb}}{\text{hr}}\right) \times [1 - \text{Destruction Rate Efficiency}(\%)/100]$$

Hourly N_2O emission rates are estimated using Equation W-40 in 40 CFR Part 98 Subpart W for combustion units that combust process vent gas, as shown in the following equation:[5]

$$\begin{aligned} \text{N}_2\text{O Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \\ &= \text{Waste Gas Flowrate}\left(\frac{\text{MMscf}}{\text{day}}\right) \times \frac{1\text{ day}}{24\text{ hr}} \times \frac{10^6\text{ scf}}{1\text{ MMscf}} \times \text{Process Gas HHV}\left(\frac{\text{MMBtu}}{\text{scf}}\right) \\ &\times \text{N}_2\text{O Emission Factor}\left(\frac{\text{kg}}{\text{MMBtu}}\right) \times \frac{2.2046\text{ lb}}{1\text{ kg}} \end{aligned}$$

The process gas HHV is taken from 40 CFR §98.233(z)(2)(vi). The N_2O emission factor is obtained from Table C-2 in 40 CFR Part 98 Subpart C for natural gas.

In addition to emissions from combusted CO_2, CH_4, and N_2O, GHG emissions will result from the conversion of carbon atoms in the waste streams to CO_2. For sources that combust process vent gas, the converted emissions are estimated based on Equations W-39A and W-39B obtained from 40 CFR Part 98 Subpart W.[6] The following equation is used to determine the CO_2 emissions resulting from the oxidation of methane (compounds with one carbon atom), ethane

[5] 40 CFR §98.233(z)(2)(vi).

[6] 40 CFR §98.233(z)(2)(iii).

(compounds with two carbon atoms), propane (compounds with three carbon atoms), butanes (compounds with four carbon atoms), and pentanes+ (compounds with five or more carbon atoms):

$$\text{Converted } CO_2 \text{ Hourly Emission Rate} = \text{Inlet to Flare}\left(\frac{\text{lb}}{\text{hr}}\right) \text{ x Carbon Count x Destruction Rate Efficiency } (\%)/100$$

All annual emission rates are based on maximum operation equivalent to 8,760 hrs/yr, using the following equation:

$$\text{Controlled Annual Emission Rate (tpy)} = \text{Controlled Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Hours of Operation}\left(\frac{\text{hr}}{\text{yr}}\right) \times \left(\frac{\text{ton}}{2{,}000\text{ lb}}\right)$$

MSS Emissions

Uncontrolled CH_4 emissions from the MSS activities are calculated using a mass balance approach and the following equations for gaseous and liquid activities, respectively:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Gas Volume per Event}\left(\frac{\text{scf}}{\text{event}}\right) \times \frac{1}{\text{Event Duration}\left(\frac{\text{hr}}{\text{event}}\right)} \times \text{Component Vapor Mass Fraction} \times \text{Vapor Density}\left(\frac{\text{lb}}{\text{scf}}\right)$$

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Liquid Volume per Event}\left(\frac{\text{scf}}{\text{event}}\right) \times \frac{1}{\text{Event Duration}\left(\frac{\text{hr}}{\text{event}}\right)} \times \text{Component Liquid Mass Fraction} \times \text{Liquid Density}\left(\frac{\text{lb}}{\text{scf}}\right)$$

Controlled hourly emission rates for CH_4 from the flare are estimated using the inlet to the flare and the guaranteed destruction efficiency of the flare. The following equation is used to estimate hourly CH_4 emission rates from the controlled streams:

$$\text{Controlled Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Inlet to Flare}\left(\frac{\text{lb}}{\text{hr}}\right) \times [1 - \text{Destruction Rate Efficiency}(\%)/100]$$

Hourly N_2O emission rates are estimated using Equation W-40 in 40 CFR Part 98 Subpart W for combustion units that combust process vent gas, as shown in the following equation:[7]

[7] 40 CFR §98.233(z)(2)(vi).

$$N_2O \text{ Hourly Emission Rate } \left(\frac{\text{lb}}{\text{hr}}\right)$$
$$= \text{Waste Gas Flowrate} \left(\frac{\text{MMscf}}{\text{day}}\right) \times \frac{1 \text{ day}}{24 \text{ hr}} \times \frac{10^6 \text{ scf}}{1 \text{ MMscf}} \times \text{Process Gas HHV} \left(\frac{\text{MMBtu}}{\text{scf}}\right)$$
$$\times N_2O \text{ Emission Factor} \left(\frac{\text{kg}}{\text{MMBtu}}\right) \times \frac{2.2046 \text{ lb}}{1 \text{ kg}}$$

The process gas HHV is taken from 40 CFR §98.233(z)(2)(vi). The N_2O emission factor is obtained from Table C-2 in 40 CFR Part 98 Subpart C for natural gas.

In addition to emissions from combusted CH_4 and N_2O, GHG emissions will result from the conversion of carbon atoms in the MSS streams to CO_2. The converted emissions are estimated based on Equations W-39A and W-39B obtained from 40 CFR Part 98 Subpart W.[8] The following equation is used to determine the CO_2 emissions resulting from the oxidation of methane (compounds with one carbon atom), ethane (compounds with two carbon atoms), propane (compounds with three carbon atoms), butanes (compounds with four carbon atoms), and pentanes+ (compounds with five or more carbon atoms):

$$\text{Converted } CO_2 \text{ Hourly Emission Rate} = \text{Inlet to Flare} \left(\frac{\text{lb}}{\text{hr}}\right) \text{ x Carbon Count x Destruction Rate Efficiency } (\%)/100$$

Controlled annual emission rates from MSS activities are estimated based on hourly emission rates, event frequency, and event duration, using the following equation:

$$\text{Annual Emission Rate (tpy)}$$
$$= \text{Controlled Hourly Emission Rate} \left(\frac{\text{lb}}{\text{hr}}\right) \times \text{ Event Frequency} \left(\frac{\text{event}}{\text{yr}}\right) \times \text{Event Duration} \left(\frac{\text{hr}}{\text{event}}\right)$$
$$\times \left(\frac{\text{ton}}{2{,}000 \text{ lb}}\right)$$

7.3. FUGITIVE COMPONENTS

Process fugitive GHG emissions result from leaking piping components such as valves and flanges (EPN FUG-FRAC5).

Emissions from fugitive equipment leaks are calculated using fugitive component counts for the proposed equipment in the Train 5 Project, the GHG content of each stream for which component counts are placed in service, and emission factors for each component type taken from the TCEQ Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives.[9] Targa has selected to implement the 28 VHP Monitoring Program; therefore, these control efficiencies are applied to the equipment leak fugitive calculations. Additionally, Targa will monitor flanges using quarterly organic vapor analyzer (OVA) monitoring at the same leak definition for valves, resulting in the same control efficiency applied to flanges as is applied to valves.

[8] 40 CFR §98.233(z)(2)(iii).

[9] TCEQ, Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000.

Hourly Emissions

Hourly emissions of GHG from traditional fugitive components (i.e., valves and flanges) are estimated using TCEQ emission factors, component counts, and the GHG content of each stream. The following equation is used to estimate hourly CO_2 and CH_4 emissions:

$$\text{Hourly Emission Rate (lb/hr)} = \text{TCEQ Emission Factor}\left(\frac{\text{lb}}{\text{hr-comp}}\right) \times \text{Number of Components (\# comp)} \times \text{Compound Content (wt \%)} \times (1 - \text{28 VHP Control Factor(\%)})$$

Annual Emissions

Annual emissions are estimated based on hourly emissions rates and maximum operation equivalent to 8,760 hrs/yr, as shown in the following equation:

$$\text{Annual Emission Rate (tpy)} = \text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Hours of Operation}\left(\frac{\text{hr}}{\text{yr}}\right) \times \left(\frac{\text{ton}}{\text{2,000 lb}}\right)$$

7.4. FUGITIVE MSS ACTIVITIES

Fugitive CH_4 emissions may occur from maintenance and shutdown activities when the gases are vented directly to the atmosphere. Fugitive emissions from the MSS activities are calculated using a mass balance approach and the following equations for gaseous and liquid activities, respectively:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Gas Volume per Event}\left(\frac{\text{scf}}{\text{event}}\right) \times \frac{1}{\text{Event Duration}\left(\frac{\text{hr}}{\text{event}}\right)} \times \text{Component Vapor Mass Fraction} \times \text{Vapor Density}\left(\frac{\text{lb}}{\text{scf}}\right)$$

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Liquid Volume per Event}\left(\frac{\text{scf}}{\text{event}}\right) \times \frac{1}{\text{Event Duration}\left(\frac{\text{hr}}{\text{event}}\right)} \times \text{Component Liquid Mass Fraction} \times \text{Liquid Density}\left(\frac{\text{lb}}{\text{scf}}\right)$$

Annual CH_4 emission rates from fugitive MSS activities are estimated based on hourly emission rates, event frequency, and event duration, using the following equation:

$$\text{Annual Emission Rate (tpy)} = \text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Event Frequency}\left(\frac{\text{event}}{\text{yr}}\right) \times \text{Event Duration}\left(\frac{\text{hr}}{\text{event}}\right) \times \left(\frac{\text{ton}}{\text{2,000 lb}}\right)$$

Targa Midstream Services LLC - Mont Belvieu Plant Train 5
GHG Summary Table

Summary of GHG Hourly Emissions

	Hourly Emissions (lb/hr)											
GHG Pollutants	Controlled TEG-2 Emissions (FLR-5)	Controlled AU-4 Emissions (FLR-5)	Hot Oil Heater (F5A)	Hot Oil Heater (F5B)	Fugitives (FUG-FRAC5)	Flare Pilot & Supplemental Fuel (FLR-5)	Controlled Maintenance Emissions (FLR-5)	Maintenance Emissions to Atmosphere (Maintenance)	Controlled Startup Emissions (FLR-5)	Controlled Shutdown Emissions (FLR-5)	Shutdown Emissions to Atmosphere (Shutdown)	Total [1]
CO_2	291.91	2,688.37	16,884.46	16,884.46	2.35E-03	812.31	20,279.46	-	41,017.32	41,465.66	-	57,840.96
CH_4	5.53E-03	9.09E-03	0.32	0.32	0.03	0.02	1.57	3.17	3.33	3.26	7.42	7.42
N_2O	3.47E-03	6.56E-03	0.03	0.03	-	1.53E-03	2.72E-04	-	6.48E-04	1.37E-03	-	0.08
CO_2e	293.10	2,690.59	16,901.02	16,901.02	0.53	813.10	20,312.49	66.66	41,087.42	41,534.48	155.85	57,911.86

[1] The total hourly emissions are calculated based on the maximum emissions rate between maintenance and normal operations, startup, and shutdown (controlled and to atmosphere). Maintenance emissions occur at the same time as normal operation. Maintenance emissions to the flare do not occur at the same time as maintenance emissions to the atmosphere. Startup emissions do not occur during normal operation or maintenance. Shutdown emissions do not occur during normal operation or maintenance. Startup and shutdown emissions do not occur at the same time. Controlled shutdown of liquid releases, controlled shutdown of vapor releases, and uncontrolled shutdown emissions do not occur at the same time.

Maximum hourly emissions are taken from the following operating scenarios:

(1) TEG-2 to FLR-5, AU-4 to FLR-5, F5A, F5B, Frac5, Pilot & Supplemental Fuel to FLR-5, Maintenance to FLR-5
(2) TEG-2 to FLR-5, AU-4 to FLR-5, F5A, F5B, Frac5, Pilot & Supplemental Fuel to FLR-5, Maintenance to Atmosphere
(3) Startup to FLR-5
(4) Shutdown to FLR-5
(5) Shutdown to Atmosphere

Summary of GHG Annual Emissions

	Annual Emissions (tpy)											
GHG Pollutants	Controlled TEG-2 Emissions (FLR-5)	Controlled AU-4 Emissions (FLR-5)	Hot Oil Heater (F5A)	Hot Oil Heater (F5B)	Fugitives (FUG-FRAC5)	Flare Pilot & Supplemental Fuel (FLR-5)	Controlled Maintenance Emissions (FLR-5)	Maintenance Emissions to Atmosphere (Maintenance)	Controlled Startup Emissions (FLR-5)	Controlled Shutdown Emissions (FLR-5)	Shutdown Emissions to Atmosphere (Shutdown)	Total [1]
CO_2	1,278.56	11,775.04	73,953.92	73,953.92	0.01	3,557.92	302.95	-	280.24	400.59	-	165,503.16
CH_4	0.02	0.04	1.39	1.39	0.11	0.07	0.02	0.03	0.02	0.03	0.05	3.18
N_2O	0.02	0.03	0.14	0.14	-	6.70E-03	6.17E-06	-	1.85E-05	1.88E-05	-	0.33
CO_2e	1,283.79	11,784.78	74,026.45	74,026.45	2.33	3,561.40	303.36	0.65	280.76	401.13	1.04	165,672.14

[1] The total annual emissions is calculated based on the emissions rate of annual maintenance and normal operations, startup, and shutdown (controlled and to atmosphere).

FLR-5 Emission Factors [1]

Units	CO	NO_x
lb/MMBtu	0.5496	0.0641
ppmw	-	-

[1] Flare Emissions factors are from TCEQ Air Permits Division, *Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers,* RG-109 (Draft), October 2000, Table 4 (other, low Btu).

Controlled Hydrocarbon Regenerator Emissions [1, 2]

Component	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
Methane	0.0004	0.0015
Ethane	0.2819	1.2346
Propane	0.0140	0.0612
Total VOC Emissions	0.0140	0.0612

[1] Emissions from GRI-GLYCalc 4.0.
[2] Emissions are routed to FLR-5 with a control efficiency of 99% for compounds with up to three carbon atoms, per TCEQ flare guidance.

Controlled Flash Gas Hydrocarbon Emissions [1, 2]

Component	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
Methane	0.0052	0.0227
Ethane	1.1306	4.9520
Propane	0.0239	0.1046
Total VOC Emissions	0.0239	0.1046

[1] Emissions from GRI-GLYCalc 4.0.
2 Emissions are routed to FLR-5 with a control efficiency of 99% for compounds with up to three carbon atoms, per TCEQ flare guidance.

Speciated Gas Heating Rate

Speciated Gas	Higher Heating Value (Btu/lb)	Speciated Gas Percentage (%) [1] Regenerator Overheads	Flash Gas	Gas Heating Rate (MMBtu/hr) [2] Uncontrolled Regenerator Overheads	Uncontrolled Flash Gas
Methane	23,900	7.44E-03	0.84	7.11E-08	1.04E-04
Ethane	22,400	3.17	97.50	0.02	0.01
Propane	21,700	0.11	1.40	3.25E-05	1.58E-04
			Total	0.02	0.01

[1] Speciation for streams routed to the flare obtained from GRI-GLYCalc 4.0.
[2] Speciated Gas Heating Rate (MMBtu/hr) = Controlled Gas Mass Flow Rate (lb/hr) / (1-Flare Control Efficiency (%)) x Component Content (%) / 100 x Higher Heating Value (Btu/lb) x 1 MMBtu / 1,000,000 Btu

Design Specifications

Parameter	Units	Regenerator Overheads	Flash Gas Emissions
Annual Hours of Operation	hr/yr	8,760	8,760
Flare Destruction Efficiency for C1-C3 [2]	%	99	99

[1] Obtained from GRI-GLYCalc 4.0.
[2] Per TCEQ Air Permits Division, *Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers*, RG-109 (Draft), October 2000.

FLR-5 Combustion Emissions from TEG-2

FIN	EPN	Gas Stream	Gas Volume Flow [1] scf/hr	Dry Volume Flow [2,3,4] dscf/hr	Hourly Emissions [5] (lb/hr) NO_x	CO	VOC [6]	Annual Emissions [7] (tpy) NO_x	CO	VOC [6]
TEG-2	FLR-5	Regenerator Overheads	11,300	372.90	1.29E-03	0.01	0.01	5.63E-03	0.05	0.06
		Flash Gas	1,460	1,457.78	7.45E-04	6.39E-03	0.02	3.26E-03	0.03	0.10
		Total			2.03E-03	0.02	0.04	8.89E-03	0.08	0.17

[1] Gas flow rate for streams routed to flare obtained from GRI-GLYCalc 4.0
[2] Water content in the flash gas emissions stream is 0.152 Vol %.
[3] Water content in the regenerator overheads stream is 96.7 Vol %.
[4] Dry Gas Volume Flow (dscf/hr) = Gas Volume Flow (scf/hr) - [Gas Volume Flow (scf/hr) x (Water Content (Vol %) / 100)]

Flash Tank Dry Gas Volume Flow (dscf/hr) = 1460 scf/hr - (1460 scf/hr x 0.152 /100) = 1,457.78 dscf/hr

[5] Hourly Emissions of NO_x or CO (lb/hr) = Emission Factor (lb/MMBtu) x Gas Heating Rate (MMBtu/hr)

Flash Tank Hourly Emissions of NO_x (lb/hr) = $\frac{0.064\ \text{lb}}{\text{MMBtu}} \times \frac{1.16\text{E-02 MMBtu}}{\text{hr}}$ = 7.45E-04 lb/hr

[6] Emissions from GRI-GLYCalc 4.0.
[7] Annual Emissions (tpy) = Hourly Emissions (lb/hr) x 8,760 (hr/yr) x 1 ton / 2,000 lb

Flash Tank Annual Emissions of NO_x (tpy) = $\frac{7.45\text{E-04 lb}}{\text{hr}} \times \frac{8760\ \text{hr}}{\text{yr}} \times \frac{1\ \text{ton}}{2{,}000\ \text{lb}}$ = 0.00 tpy

GHG Emissions from FLR-5

Input Data		
Regenerator Overheads Gas Flowrate =	0.011	MMscf/hr (wet)
Flash Gas Flowrate =	0.00146	MMscf/hr (wet)
Hours of Operation =	8,760	hrs/yr
Higher Heating Value for N_2O [1] =	1.235E-03	MMBtu/scf

[1] Per 40 CFR Part 98, Subpart W, Equation W-40

Global Warming Potentials [1]

CO_2	CH_4	N_2O
1	21	310

[1] Global warming potentials (GWP) obtained from 40 CFR 98 Subpart A Table A-1.

N_2O Emissions

Gas Stream	Emission Factor[1,2]		N_2O Emissions[3,4]	
	(kg/MMBtu)	(lb/MMBtu)	(lb/hr)	(tpy)
Regenerator Overheads	1.00E-04	2.20E-04	3.08E-03	0.01
Flash Gas	1.00E-04	2.20E-04	3.98E-04	1.74E-03

[1] Per 40 CFR 98 Subpart W, Equation W-40.

[2] Emission factors converted from kg/MMBtu to lb/MMBtu using the following conversion: GHG Emission Factor (lb/MMBtu) = GHG Emission Factor (kg/MMBtu) x 2.2046 (lb/kg)

[3] Hourly Emission Rate for N_2O (lb/hr) = Waste Gas Flowrate (MMscf/hr) x (10^6 scf / 1 MMscf) x Subpart W Process Gas HHV (MMBtu/scf) x Emission Factor (lb/MMBtu)

Example N_2O Hourly Emissions (lb/hr) = $\frac{0.011 \text{ MMscf}}{\text{hr}} \times \frac{10^6 \text{ scf}}{1 \text{ MMscf}} \times \frac{1.235\text{E-03 MMBtu}}{\text{scf}} \times \frac{2.20\text{E-04 lb}}{\text{MMBtu}}$ = 3.08E-03 lb/hr

[4] Annual Emission Rate for N_2O (tpy) = Hourly Emission Rate (lb/hr) x Hours of Operation (hr/yr) x (1 ton / 2,000 lb)

Example N_2O Annual Emission Rate (tpy) = $\frac{3.08\text{E-03 lb}}{\text{hr}} \times \frac{8{,}760 \text{ hr}}{\text{yr}} \times \frac{1 \text{ ton}}{2{,}000 \text{ lb}}$ = 0.01 tpy

Speciated GHG Emissions

Gas Stream	Compound	Number of Carbon Atoms	DRE [1] (%)	Inlet to Flare [2] (lb/hr)	Controlled GHG Emissions [3,4] (lb/hr)	Controlled GHG Emissions [3,4] (tpy)	Converted to CO_2 [4,5] (lb/hr)	Converted to CO_2 [4,5] (tpy)
Regenerator Overheads	Carbon Dioxide	1	0%	0.15	0.15	0.67	--	--
	Methane	1	99%	0.04	3.54E-04	1.55E-03	0.04	0.15
	Ethane	2	99%	28.25	--	--	55.94	245.01
	Propane	3	99%	1.40	--	--	4.16	18.22
Flash Gas	Carbon Dioxide	1	0%	0.16	0.16	0.70	--	--
	Methane	1	99%	0.52	5.17E-03	0.02	0.51	2.24
	Ethane	2	99%	113.06	--	--	223.86	980.50
	Propane	3	99%	2.39	--	--	7.09	31.06

Total GHG Emissions [4,6]	(lb/hr)	(tpy)
CO_2	291.91	1,278.56
CH_4	0.01	0.02
N_2O	3.47E-03	0.02
CO_2e	293.10	1,283.79

[1] Per TCEQ Air Permits Division, *Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers* , RG-109 (Draft), October 2000, for compounds with no more than three carbon atoms, DRE = 99%

[2] Inlet to flare per GRI-GLYCalc 4.0 uncontrolled streams.

[3] Hourly Rate (lb/hr) = Inlet to Flare (lb/hr) x (100 - DRE(%))/100

Example Controlled Methane Hourly Emission Rate (lb/hr) = $\frac{0.04 \text{ lb}}{\text{hr}} \times \frac{(100 - 99\%)}{100}$ = 3.54E-04 lb/hr

[4] Annual Rate (tpy) = Hourly Rate (lb/hr) x Hours of Operation (hr/yr) x (1 ton / 2,000 lb)

Example Controlled Methane Annual Emission Rate (tpy) = $\frac{3.54\text{E-04 lb}}{\text{hr}} \times \frac{8{,}760 \text{ hr}}{\text{yr}} \times \frac{1 \text{ ton}}{2{,}000 \text{ lb}}$ = 1.55E-03 tpy

[5] Per 40 CFR Part 98.233(z) (Subpart W), for fuel combustion units that combust process vent gas, the following equation is used to estimate the GHG emissions from additional carbon compounds in the fuel.

Hourly Emission Rate for Compounds Converted to CO_2 (lb/hr) = Inlet to Flare (lb/hr) x DRE (%)/100 x Carbon Count (#)

Example Converted Methane Hourly Emission Rate (lb/hr) = $\frac{0.04 \text{ lb}}{\text{hr}} \times \frac{99\%}{100} \times 1$ = 0.04 lb/hr

[6] CO_2e Hourly Emission Rate (lb/hr) = CO_2 Emission Rate (lb/hr) x CO_2 GWP + CH_4 Emission Rate (lb/hr) x CH_4 GWP + N_2O Emission Rate (lb/hr) x N_2O GWP

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{291.91 \text{ lb}}{\text{hr}} \times 1 + \frac{5.53\text{E-03 lb}}{\text{hr}} \times 21 + \frac{3.47\text{E-03 lb}}{\text{hr}} \times 310$ = 293.10 lb/hr

FLR-5 Emission Factors [1]

Units	CO	NO_x	H_2S
lb/MMBtu	0.5496	0.0641	--
ppmw	--	--	0.03

[1] Flare NO_x and CO emissions factors are from TCEQ Air Permits Division, *Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers,* RG-109 (Draft), October 2000, Table 4 (other, low Btu).

Speciated Gas Heating Rate

Speciated Gas	Higher Heating Value (Btu/lb)	Speciated Gas Percentage [1] (%)		Gas Heating Rate (MMBtu/hr)	
		Flash Gas	Acid Gas	Flash Gas [2]	Acid Gas [2]
Methane	23,900	0.97	5.37E-03	0.02	3.30E-03
Ethane	22,400	97.15	0.96	1.72	0.55
Propane	21,700	1.25	0.01	0.02	7.14E-03
				1.76	0.56

[1] Based on similar operations at the facility.
[2] Speciated Gas Heating Rate (MMBtu/hr) = Gas Mass Flow Rate (lb/hr) x Component Content (%) / 100 x Higher Heating Value (Btu/lb) x 1 MMBtu / 1,000,000 Btu

Gas Heating Rate of Methane in the Flash Gas (MMBtu/hr) = $\frac{79.1 \text{ lb}}{\text{hr}} \left| \frac{0.97\%}{100} \right| \frac{23,900 \text{ Btu}}{\text{lb}} \left| \frac{1 \text{ MMBtu}}{1,000,000 \text{ Btu}} \right.$ = 0.02 MMBtu/hr

Parameter	Units	Flash Gas	Acid Gas
Gas Volume Flow Rate [1]	MMscf/day	0.02	0.55
Gas Mass Flow Rate [1]	lb/hr	79.10	2,571.91
Annual Hours of Operation	hr/yr	8,760	8,760
Flare Destruction Efficiency for C1-C3 [2]	%	99	99
Flare Destruction Efficiency for C4+ [2]	%	98	98

[1] Based on similar operations at the facility.
[2] Per TCEQ Air Permits Division, *Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers* , RG-109 (Draft), October 2000.

Amine Unit Outlet Streams

Speciated Gas	Speciated Gas Percentage (%)	
	Flash Gas [1]	Acid Gas [1]
Carbon Dioxide	0.21	96.52
Methane	0.97	5.37E-03
Ethane	97.15	0.96
Propane	1.25	0.01
Ucarsol AP-810	8.41E-05	5.65E-05
Total VOC Content (%)	1.25	0.01

[1] Based on similar operations at the facility.

Targa Midstream Services LLC - Mont Belvieu Plant
Amine Unit Emissions Calculations

Controlled Flash Gas Emissions [1, 2]

Component	Inlet to Flare (lb/hr)	Destruction Efficiency (%)	Controlled Hourly Emissions (lb/hr)	Controlled Annual Emissions (tpy)
Carbon Dioxide	0.17	0%	0.17	0.72
Methane	0.77	99%	7.71E-03	0.03
Ethane	76.85	99%	0.77	3.37
Propane	0.99	99%	9.90E-03	0.04
Ucarsol AP-810	6.65E-05	98%	1.33E-06	5.83E-06
Total VOC Emissions			9.91E-03	0.04

[1] Emissions based on similar operations at the facility.
[2] Hourly Emissions of VOC (lb/hr) = (100 - (Flare Efficiency (%))/100 x Gas Mass Flow Rate (lb/hr) x VOC Component Content (%)/100

Hourly Emissions of Propane (lb/hr) = $\frac{100-99\%}{100} \left| \frac{79.10 \text{ lb}}{\text{hr}} \right| \frac{1.25\%}{100}$ = 9.90E-03 lb/hr

Controlled Acid Gas Emissions [1, 2]

Component	Inlet to Flare (lb/hr)	Destruction Efficiency (%)	Controlled Hourly Emissions (lb/hr)	Controlled Annual Emissions (tpy)
Carbon Dioxide	2482.41	0%	2,482.41	10,872.95
Methane	0.14	99%	1.38E-03	6.05E-03
Ethane	24.65	99%	0.25	1.08
Propane	0.33	99%	3.29E-03	0.01
Ucarsol AP-810	1.45E-03	98%	2.90E-05	1.27E-04
Total VOC Emissions			3.32E-03	0.01

[1] Emissions based on similar operations at the facility.
[2] Hourly Emissions of VOC (lb/hr) = (100 - (Flare Efficiency (%))/100 x Gas Mass Flow Rate (lb/hr) x VOC Component Content (%)/100

Hourly Emissions of Propane (lb/hr) = $\frac{100-99\%}{100 \text{ hr}} \left| \frac{2{,}571.91 \text{ lb}}{\text{hr}} \right| \frac{1.25\%}{100}$ = 3.29E-03 lb/hr

Targa Midstream Services LLC - Mont Belvieu Plant
Amine Unit Emissions Calculations

FLR-5 Combustion Emissions from AU-4

				Hourly Emissions (lb/hr)					Annual Emissions (tpy)				
FIN	**EPN**	**Source Name**	**Gas Stream**	**NO_x [1]**	**CO [1]**	**VOC [2]**	**SO_2 [3,4,7,8]**	**H_2S [3,4,5,6]**	**NO_x [9]**	**CO [9]**	**VOC [2]**	**SO_2 [10,11]**	**H_2S [10,11]**
AU-4	FLR-5	Amine Unit	Flash Gas	0.11	0.97	9.91E-03	--	--	0.49	4.24	0.04	--	--
			Acid Gas	0.04	0.31	3.32E-03	0.09	9.32E-04	0.16	1.35	0.01	0.19	2.04E-03
			Total	0.15	1.28	0.01	0.09	9.32E-04	0.65	5.59	0.06	0.19	2.04E-03

[1] Hourly Emissions of NO_x or CO (lb/hr) = Emission Factor (lb/MMBtu) x Gas Heating Rate (MMBtu/hr)

Flash Gas Hourly Emissions of NO_x (lb/hr) =	0.064 lb / MMBtu	1.76 MMBtu / hr	=	0.11 lb/hr

[2] VOC emissions estimated above.

[3] The hourly emission rates for H_2S and SO_2 are 200% the daily average for conservative purposes.

[4] The inlet volume flow rate containing H_2S is 110,000 barrels/day

[5] The specific gravity of the stream containing H_2S is 0.484

[6] Hourly Emissions of H_2S (lb/hr) = 2 * (1-(Flare Destruction Efficiency (%) / 100)) * (H_2S Emission Factor (ppmw) / 1,000,000) * Volume Flow Rate (barrels/day) * 42 (gal/barrel) * 8.34 (lb/gal) * Specific Gravity * 1 / 24 (day/hr)

Hourly Emissions of H_2S (lb/hr) =	2	1-(98%/100)	0.03 parts H2S / 1,000,000	110,000 barrels / day	42 gal / barrel	8.34 lb / gal	0.484	1 day / 24 hr	=	9.32E-04 lb/hr

[7] The molecular weight ratio of SO_2/H_2S is 1.88

[8] Hourly Emissions of SO_2 (lb/hr) = 2 * (Flare Destruction Efficiency (%) / 100) * (H_2S Emission Factor (ppmw) / 1,000,000) * Volume Flow Rate (barrels/day) * 42 (gal/barrel) * Specific Gravity * Molecular Weight Ratio of SO_2/H_2S * 1 / 24 (day/hr)

Hourly Emissions of SO_2 (lb/hr) =	2	98% / 100	0.03 parts H2S / 1,000,000	110,000 barrels / day	42 gal / barrel	8.34 lb / gal	0.48	1.88	1 day / 24 hr	=	0.09 lb/hr

[9] Annual Emissions of NO_x or CO (tpy) = Hourly Emissions (lb/hr) x 8,760 (hr/yr) x 1 ton / 2,000 lb

Flash Gas Annual Emissions of NO_x (tpy) =	0.11 lb / hr	8760 hr / yr	1 ton / 2,000 lb	=	0.49 tpy

[10] H_2S and SO_2 annual emissions rates do not include the conservative safety factor of 200%.

[11] H_2S and SO_2 Annual Emissions (tpy) = Hourly Emissions (lb/hr) * 8,760 (hr/yr) * 1 / 2,000 (ton/lb) * 1 / 2

Annual Emissions of H_2S (tpy) =	0.09 lb / hr	8,760 hr / yr	1 ton / 2,000 lb	1 / 2	=	0.19 tpy

GHG Emissions - Amine Acid Gas Combustion

Input Data		
Maximum Amine Acid Gas Flowrate =	2,571.91	lb/hr
	0.55	MMscf/day
Maximum Amine Flash Gas Flowrate =	79.10	lb/hr
	0.02	MMscf/day
Hours of Operation =	8,760	hrs/yr
Higher Heating Value for N_2O [1] =	1.235E-03	MMBtu/scf

[1] Per 40 CFR Part 98, Subpart W, Equation W-40

Amine Unit Outlet Streams

Speciated Gas	Speciated Gas Percentage (%) Flash Gas [1]	Acid Gas [1]
Carbon Dioxide	0.21	96.52
Methane	0.97	5.37E-03
Ethane	97.15	0.96
Propane	1.25	0.01
Ucarsol AP-810	8.41E-05	5.65E-05

[1] Based on similar operations at the facility.

Global Warming Potentials [1]

CO_2	CH_4	N_2O
1	21	310

[1] Global warming potentials (GWP) obtained from 40 CFR 98 Subpart A Table A-1.

N_2O Emissions

Gas Stream	Emission Factor[1,2]		N_2O Emissions[3,4]	
	(kg/MMBtu)	(lb/MMBtu)	(lb/hr)	(tpy)
Acid Gas	1.00E-04	2.20E-04	6.28E-03	0.03
Flash Gas	1.00E-04	2.20E-04	2.74E-04	1.20E-03

[1] Per 40 CFR 98 Subpart W, Equation W-40.
[2] Emission factors converted from kg/MMBtu to lb/MMBtu using the following conversion: GHG Emission Factor (lb/MMBtu) = GHG Emission Factor (kg/MMBtu) x 2.2046 (lb/kg)
[3] Hourly Emission Rate for N_2O (lb/hr) = Waste Gas Flowrate (MMscf/day) x (day / 24 hr) x (10^6 scf / 1 MMscf) x Subpart W Process Gas HHV (MMBtu/scf) x Emission Factor (kg/MMBtu) x (2.2046 lb/kg)

Example N_2O Hourly Emissions (lb/hr) = $\frac{0.55 \text{ MMscf}}{\text{day}} \times \frac{1 \text{ day}}{24 \text{ hrs}} \times \frac{10^6 \text{ scf}}{1 \text{ MMscf}} \times \frac{1.235\text{E-03 MMBtu}}{\text{scf}} \times \frac{2.20\text{E-04 lb}}{\text{MMBtu}}$ = 6.28E-03 lb/hr

[4] Annual Emission Rate for N_2O (tpy) = Hourly Emission Rate (lb/hr) x Hours of Operation (hr/yr) x (1 ton / 2,000 lb)

Example N_2O Annual Emission Rate (tpy) = $\frac{6.28\text{E-03 lb}}{\text{hr}} \times \frac{8{,}760 \text{ hr}}{\text{yr}} \times \frac{1 \text{ ton}}{2{,}000 \text{ lb}}$ = 0.03 tpy

Speciated GHG Emissions

Gas Stream	Compound	Number of Carbon Atoms	DRE [1] (%)	Inlet to Flare[2] (lb/hr)	Controlled GHG Emissions[3,4] (lb/hr)	Controlled GHG Emissions[3,4] (tpy)	Converted to CO_2 [5,6] (lb/hr)	Converted to CO_2 [5,6] (tpy)
Acid Gas	Carbon Dioxide	1	0%	2,482.41	2482.41	10,872.95	--	--
	Methane	1	99%	0.14	1.38E-03	0.01	0.14	0.60
	Ethane	2	99%	24.65	--	--	48.81	213.77
	Propane	3	99%	0.33	--	--	0.98	4.28
	Ucarsol AP-810	5	98%	1.45E-03	--	--	0.01	0.03
Flash Gas	Carbon Dioxide	1	0%	0.17	0.17	0.72	--	--
	Methane	1	99%	0.77	7.71E-03	0.03	0.76	3.34
	Ethane	2	99%	76.85	--	--	152.16	666.46
	Propane	3	99%	0.99	--	--	2.94	12.88
	Ucarsol AP-810	5	98%	6.65E-05	--	--	3.26E-04	1.43E-03

Total GHG Emissions [7]	(lb/hr)	(tpy)
CO_2	2,688.37	11,775.04
CH_4	9.09E-03	0.04
N_2O	0.01	0.03
CO_2e	2,690.59	11,784.78

[1] Per TCEQ Air Permits Division, *Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers* , RG-109 (Draft), October 2000, for compounds with no more than three carbon atoms, DRE = 99%. Otherwise, DRE = 98%.

[2] Inlet to Flare (lb/hr) = Gas Flow Rate (lb/hr) x Speciated Gas Percentage [%]/100

Example Acid Gas Methane Inlet to Flare (lb/hr) = $\frac{2{,}571.91 \text{ lb}}{\text{hr}} \Big| \frac{5.37\text{E-}03\%}{100}$ = 0.14 lb/hr

[3] Controlled Flare Maximum Potential Hourly Emission Rate (lb/hr) = Inlet to Flare (lb/hr) x (100 - DRE(%))/100

Example Controlled Methane Hourly Emission Rate (lb/hr) = $\frac{0.14 \text{ lb}}{\text{hr}} \Big| \frac{(100 - 99\%)}{100}$ = 1.38E-03 lb/hr

[4] Controlled Flare Maximum Potential Annual Rate (tpy) = Controlled Hourly Rate (lb/hr) x Hours of Operation (hr/yr) x (1 ton / 2,000 lb)

Example Controlled Methane Annual Emission Rate (tpy) = $\frac{1.38\text{E-}03 \text{ lb}}{\text{hr}} \Big| \frac{8{,}760 \text{ hr}}{\text{yr}} \Big| \frac{1 \text{ ton}}{2{,}000 \text{ lb}}$ = 6.05E-03 tpy

[5] Per 40 CFR Part 98.233(z) (Subpart W), for fuel combustion units that combust process vent gas, the following equation is used to estimate the GHG emissions from additional carbon compounds in the fuel.

Hourly Emission Rate for Compounds Converted to CO_2 (lb/hr) = Inlet to Flare (lb/hr) x DRE (%)/100 x Carbon Count (#)

Example Converted Methane Hourly Emission Rate (lb/hr) = $\frac{0.14 \text{ lb}}{\text{hr}} \Big| \frac{99\%}{100} \Big| 1$ = 0.14 lb/hr

[6] Annual Emission Rate for Compounds Converted to CO_2 (tpy) = Converted Hourly Rate (lb/hr) x Hours of Operation (hr/yr) x (1 ton / 2,000 lb)

Example Converted Methane Annual Emission Rate (tpy) = $\frac{0.14 \text{ lb}}{\text{hr}} \Big| \frac{8{,}760 \text{ hr}}{\text{yr}} \Big| \frac{1 \text{ ton}}{2{,}000 \text{ lb}}$ = 0.60 tpy

[7] CO_2e Hourly Emission Rate (lb/hr) = CO_2 Emission Rate (lb/hr) x CO_2 GWP + CH_4 Emission Rate (lb/hr) x CH_4 GWP + N_2O Emission Rate (lb/hr) x N_2O GWP

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{2688.37 \text{ lb}}{\text{hr}} \Big| 1$ + $\frac{9.09\text{E-}03 \text{ lb}}{\text{hr}} \Big| 21$ + $\frac{0.01 \text{ lb}}{\text{hr}} \Big| 310$ = 2690.59 lb/hr

GHG Emission Factors - Natural Gas Combustion

Greenhouse Gas	Global Warming Potential[1]	Emission Factor[2,3] (kg/MMBtu)	(lb/MMBtu)
CO_2	1	53.02	116.89
CH_4	21	1.0E-03	2.20E-03
N_2O	310	1.0E-04	2.20E-04

[1] Per 40 CFR Part 98 dated July 12, 2010, Table A-1 of Subpart A - *Global Warming Potentials (100-year time horizon)*; used to convert emissions of each GHG to a CO_2 equivalent basis.

[2] Per 40 CFR Part 98 dated December 17, 2010, Table C-1 of Subpart C - *Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel* and Table C-2 of Subpart C - *Default CH_4 and N_2O Emission Factors for Various Types of Fuel*. Emission factors for natural gas (unspecified heat value, weighted U.S. average) are used.

[3] Emission factors converted from kg/MMBtu to lb/MMBtu using the following conversion: GHG Emission Factor (lb/MMBtu) = GHG Emission Factor (kg/MMBtu) x 2.2046 (lb/kg)

$$CO_2 \text{ Emission Factor (lb/MMBtu)} = \frac{53.02 \text{ kg}}{\text{MMBtu}} \left| \frac{2.2046 \text{ lb}}{\text{kg}} \right. = 116.89 \text{ lb/MMBtu}$$

GHG Emission Rates from Natural Gas Combustion

FIN	EPN	Source Name	Maximum Design Capacity (MMBtu/hr)	Annual Hours of Operation (hr/yr)	Hourly Emissions (lb/hr)[1,2] CO_2	CH_4	N_2O	CO_2e	Annual Emissions (tpy)[1] CO_2	CH_4	N_2O	CO_2e
F5A	F5A	Hot Oil Heater	144.45	8,760	16,884	0.32	0.03	16,901.02	73,954	1.39	0.14	74,026.45
F5B	F5B	Hot Oil Heater	144.45	8,760	16,884	0.32	0.03	16,901.02	73,954	1.39	0.14	74,026.45

[1] Sample Calculation for CO_2 emissions:

CO_2 Hourly Emission Rate (lb/hr) = (Emission Factor [lb/MMBtu]) x (Heat Input Capacity [MMBtu/hr])

$$CO_2 \text{ Emission Rate (lb/hr)} = \frac{116.89 \text{ lb CO2}}{\text{MMBtu}} \left| \frac{144.45 \text{ MMBtu}}{\text{hr}} \right. = 16{,}884 \text{ lb/hr}$$

CO_2 Annual Emission Rate (tpy) = (Hourly Emission Rate [lb/hr]) x (Maximum Annual Operation [hr/yr]) x (0.001102 ton/kg)

$$CO_2 \text{ Emission Rate (tpy)} = \frac{16{,}884 \text{ lb}}{\text{hr}} \left| \frac{8760 \text{ hr}}{\text{yr}} \right| \frac{\text{ton}}{2000 \text{ lb}} = 73{,}954 \text{ tpy}$$

[2] Sample Calculation for CO_2e emissions:

CO_2e Emission Rate (lb/hr) = (CO_2 Emission Rate [lb/hr]) x (CO_2 GWP) + (CH_4 Emission Rate [lb/hr]) x (CH_4 GWP) + (N_2O Emission Rate [lb/hr]) x (N_2O GWP)

$$CO_2e \text{ Emission Rate (lb/hr)} = \frac{16{,}884 \text{ lb}}{\text{hr}} \left| \frac{1 \text{ CO}_2\text{e}}{1 \text{ lb CO}_2} \right. + \frac{0.32 \text{ lb}}{\text{hr}} \left| \frac{21 \text{ lb CO}_2\text{e}}{1 \text{ lb CH}_4} \right. + \frac{0.03 \text{ lb}}{\text{hr}} \left| \frac{310 \text{ lb CO}_2\text{e}}{1 \text{ lb N}_2\text{O}} \right. = 16{,}901 \text{ lb CO2e/hr}$$

Targa Midstream Services LLC - Mont Belvieu Plant
Fugitives GHG Emissions Calculations

Product Stream Fugitive Component Counts[1]

Product Stream	Number of Valves Gas/Vapor	Number of Valves Liquid	Number of Flanges Gas/vapor	Number of Flanges Liquid
YGRD	0	136	31	279
DC2T	53	479	121	1085
DC2B	7	61	16	142
DC3T	66	375	102	917
DC3B	6	50	13	118
DC4T	14	124	31	277
DC4B	23	211	52	471
C4ST	29	261	66	592
C4SB	27	246	64	576
FUELGAS	71	0	220	0

[1] Based on similar operations at the facility.

Oil and Gas Production Operations Emission Factors

Equipment	Units	Gas [1]	Liquid [1]
Valves	(lb/hr)/component	0.00992	0.0055
Flanges	(lb/hr)/component	0.00086	0.000243

[1] Oil and Gas Production emission factors obtained from TCEQ guidance:
http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/fac_specific.pdf,
Accessed February 2012.

TCEQ LDAR Control Efficiencies

LDAR Program	Units	Gas [1]	Liquid [1]
Valves	%	97	97
Flanges	%	97	97

[1] Control efficiencies for 28VHP LDAR program obtained from TCEQ guidance:
http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/control_eff.pdf, Accessed February 2012. Targa will monitor flanges using quarterly OVA monitoring at the same leak definition for valves; therefore, the 97% control efficiency may be used for flanges.

Global Warming Potentials [1]

CO_2	CH_4	N_2O
1	21	310

[1] Global warming potentials (GWP) obtained from 40 CFR 98 Subpart A Table A-1.

Proposed Hourly and Annual Emissions from Fugitive Components

			Hourly Emissions (lb/hr) [1]					Annual Emissions (tpy) [2]				
			Valves		Flanges			Valves		Flanges		
FIN	EPN	Product Stream	Gas	Liquid	Gas	Liquid	Total TOC	Gas	Liquid	Gas	Liquid	Total TOC
FUG-FRAC5	FUG-FRAC5	YGRD	-	0.02	8.00E-04	2.03E-03	0.03	-	0.10	3.50E-03	8.91E-03	0.11
FUG-FRAC5	FUG-FRAC5	DC2T	0.02	0.08	3.12E-03	7.91E-03	0.11	0.07	0.35	0.01	0.03	0.46
FUG-FRAC5	FUG-FRAC5	DC2B	2.08E-03	0.01	4.13E-04	1.04E-03	0.01	9.12E-03	0.04	1.81E-03	4.53E-03	0.06
FUG-FRAC5	FUG-FRAC5	DC3T	0.02	0.06	2.63E-03	6.68E-03	0.09	0.09	0.27	0.01	0.03	0.40
FUG-FRAC5	FUG-FRAC5	DC3B	1.79E-03	8.25E-03	3.35E-04	8.60E-04	0.01	7.82E-03	0.04	1.47E-03	3.77E-03	0.05
FUG-FRAC5	FUG-FRAC5	DC4T	4.17E-03	0.02	8.00E-04	2.02E-03	0.03	0.02	0.09	3.50E-03	8.84E-03	0.12
FUG-FRAC5	FUG-FRAC5	DC4B	6.84E-03	0.03	1.34E-03	3.43E-03	0.05	0.03	0.15	5.88E-03	0.02	0.20
FUG-FRAC5	FUG-FRAC5	C4ST	8.63E-03	0.04	1.70E-03	4.32E-03	0.06	0.04	0.19	7.46E-03	0.02	0.25
FUG-FRAC5	FUG-FRAC5	C4SB	8.04E-03	0.04	1.65E-03	4.20E-03	0.05	0.04	0.18	7.23E-03	0.02	0.24
FUG-FRAC5	FUG-FRAC5	FUELGAS	0.02	-	5.68E-03	-	0.03	0.09	-	0.02	-	0.12
		Total	0.09	0.32	0.02	0.03	0.46	0.39	1.40	0.08	0.14	2.01

[1] Hourly Emissions (lb/hr) = Component Count x Emission Factor [(lb/hr)/ component] x (1 - (28 VHP Control (%)) / 100)

Hourly Emissions from Product Stream DC2T (lb/hr) =	53	0.00992 lb / hr-component	1-(97/100)	=	0.02 lb/hr

[2] Annual Emissions (tpy) = Hourly Emissions (lb/hr) x 8,760 (hr/yr) x 1 ton /2,000 lb

Annual Emissions for Product Stream DC2T (tpy) =	0.02 lb / hr	8,760 / yr	1 ton / 2,000 lb	=	0.07 tpy

Targa Midstream Services LLC - Mont Belvieu Plant
Fugitives GHG Emissions Calculations

GHG Speciation

Component	FUELGAS	YGRD	DC2T	DC2B	DC3T	DC3B	DC4T	DC4B	C4ST	C4SB
	Product Stream Weight Percent (%) [1]									
Carbon Dioxide	5.24	0.35	0.80	2.06E-07	5.20E-07	--	--	--	--	--
Methane	88.85	0.54	1.23	1.99E-11	5.03E-11	--	--	--	--	--

[1] Based on similar operations at the facility.

Speciated Hourly GHG Emissions from Fugitive Components

Component	FUELGAS	YGRD	DC2T	DC2B	DC3T	DC3B	DC4T	DC4B	C4ST	C4SB	Total
	Hourly Emissions (lb/hr) [1]										
Carbon Dioxide	1.41E-03	8.94E-05	8.51E-04	2.79E-11	4.72E-10	--	--	--	--	--	2.35E-03
Methane	0.02	1.37E-04	1.31E-03	2.70E-15	4.57E-14	--	--	--	--	--	0.03
CO_2e	0.50	2.97E-03	0.03	2.80E-11	4.73E-10	--	--	--	--	--	0.53

[1] Speciated Hourly Emissions (lb/hr) = TOC Hourly Emissions per Product Stream (lb/hr) x (Component Weight Percent (%) /100)

Carbon Dioxide Speciated Hourly Emissions for Product Stream FUELGAS (lb/hr) = $\frac{0.03\ \text{lb}}{\text{hr}} \cdot \frac{5.24\ \%}{100}$ = 1.41E-03 lb/hr

Speciated Annual GHG Emissions from Fugitive Components

Component	FUELGAS	YGRD	DC2T	DC2B	DC3T	DC3B	DC4T	DC4B	C4ST	C4SB	Total
	Annual Emissions (tpy) [1]										
Carbon Dioxide	6.16E-03	3.92E-04	3.73E-03	1.22E-10	2.07E-09	--	--	--	--	--	0.01
Methane	0.10	6.01E-04	5.72E-03	1.18E-14	2.00E-13	--	--	--	--	--	0.11
CO2e	2.20	0.01	0.12	1.23E-10	2.07E-09	--	--	--	--	--	2.33

[1] Speciated Annual Emissions (tpy) = Hourly Emissions (lb/hr) x 8,760 (hr/yr) x 1 ton /2,000 lb

Carbon Dioxide Speciated Annual Emissions for Product Stream FUELGAS (tpy) = $\frac{1.41\text{E-03 lb}}{\text{hr}} \cdot \frac{8{,}760\ \text{hr}}{\text{yr}} \cdot \frac{1\ \text{ton}}{2{,}000\ \text{lb}}$ = 0.01 tpy

FLR-5 Emission Factors [1]

Units	CO	NO_x
lb/MMBtu	0.2755	0.138
ppmw	-	-

[1] Flare Emissions factors are from TCEQ Air Permits Division, *Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers,* RG-109 (Draft), October 2000, Table 4 (other, high Btu).

Maintenance Emissions Summary

FIN	EPN	Source Name	Hourly Emissions (lb/hr) VOC [1]	NO_x [2]	CO [2]	Annual Emissions (tpy) VOC [1]	NO_x [3]	CO [3]
Maintenance	FLR-5	Emissions to FLR-5	13.96	0.23	0.47	0.63	6.80E-03	0.01
Maintenance	Maintenance	Emissions to Atmosphere	1.15	-	-	0.01	-	-

[1] VOC emissions calculated below and based on the maximum hourly emissions among all vapor events and all liquid events.
[2] Hourly emissions of NO_x and CO based on the maximum hourly heating rate among all vapor events and liquid events.
Hourly Emissions of NO_x or CO (lb/hr) = Emission Factor (lb/MMBtu) x Gas Heating Rate (MMBtu/hr)

Hourly Emissions of NO_x (lb/hr) = 0.138 lb / MMBtu | 1.69 MMBtu / hr = 0.23 lb/hr

[3] Annual Emissions (tpy) = Emission Factor (lb/MMBtu) x Σ (Hours per Event [hr/event] x Frequency per Year [event/yr] x Gas Heating Rate [MMBtu/hr])

Gas Heating Rates [1]

Speciated Gas	Higher Heating Value (Btu/ft^3)
C1	912
C2	1,699
C3	2,385
iC4	3,105
C4	3,123
iC5	3,705
C5	3,714
C6	4,415
C7	4,415

[1] Per Table 5-7 of *Combined Heating, Cooling & Power Handbook: Technologies & Applications,* by Neil Petchers (2003)

Component Molecular Weights

Component	MW (lb/lb-mol)
C1	16.04
C2	30.07
C3	44.10
iC4	58.12
C4	58.12
iC5	72.15
C5	72.15
C6	86.18
C7	100.21

Targa Midstream Services LLC - Mont Belvieu Plant
Maintenance Emissions Calculations

Vapor Parameters

Unit ID	Description	Hours Per Event (hr/event)	Frequency per Year (event/yr)	ID (ft)	Height (ft)	Total Volume [1] (ft^3/event)	Total Volume Rate [2] (ft^3/hr)	Vapor Density (lb/ft^3)	Vapor Mass Fraction [3] C1	C2	C3	iC4	C4	iC5	C5	C6	C7	Gas Heating Rate [4] (MMBtu/hr)
Filters/Coalescers																		
15-358-1A/B	Plant inlet feed filters	4	104	3	7.25	51	13	3.35	0.0323	0.7766	0.1329	0.0269	0.0199	0.0053	0.0033	0.0004	0.0025	0.0238
15-358-2A/B	Plant feed inlet coalescers	4	104	5	5.25	103	26	3.35	0.0323	0.7766	0.1329	0.0269	0.0199	0.0053	0.0033	0.0004	0.0025	0.0478
15-358-401	Treated Propane Filter Coalescer	4	104	3	5.25	37	9	1.50	0.0000	0.1297	0.8584	0.0109	0.0010	0.0000	0.0000	0.0000	0.0000	0.0214
15-358-501	Treated gasoline coalescer	4	104	2	5.25	22	6	0.12	0.0000	0.0000	0.0000	0.0003	0.0230	0.4936	0.3272	0.0221	0.1338	0.0214
15-358-601	n-butane product coalescer	4	104	3	5.25	37	9	0.40	0.0000	0.0000	0.0000	0.0401	0.9576	0.0021	0.0001	0.0000	0.0000	0.0290
Compressors																		
11-358-1A/B	Ethane	2	6	-	-	2,000	1,000	7.72	0.0203	0.9699	0.0098	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	1.6897
11-358-2A/B	Refrigeration	2	2	-	-	1,200	600	1.50	0.0000	0.1297	0.8584	0.0109	0.0010	0.0000	0.0000	0.0000	0.0000	1.3828
11-358-3	C4 Splitter	2	2	-	-	1,000	500	0.59	0.0000	0.0000	0.0225	0.9647	0.0128	0.0000	0.0000	0.0000	0.0000	1.5445

[1] Total Volume (ft^3/event) = Pi * (ID (ft) / 2)^2 x Height (ft)

Filters/Coalescer 15-358-1A/B Total Volume (ft^3/event) = π | (3 ft / 2)^2 | 7.25 ft = 51 ft^3/event

[2] Total Volume Rate (ft^3/hr) = Total Volume (ft^3/event) / Hours Per Event (hr/event)

Filters/Coalescer 15-358-1A/B Total Volume (ft^3/hr) = 51 ft^3 / event | event / 4 hr = 13 ft^3/hr

[3] The mass fraction ratio of n-hexane to n-hexane and higher is 14.2 %

[4] Speciated Gas Heating Rate (MMBtu/hr) = Gas Volume Flow Rate (ft^3/hr) x Component Mass Fraction x Higher Heating Value (Btu/ft^3) x 1 MMBtu / 1,000,000 Btu

Vapor Emissions to FLR-5[1]

Unit ID	Description	Controlled Weight Per Hour (lb/hr) [2] C1	C2	C3	iC4	C4	iC5	C5	C6	C7	Controlled Weight Per Year (lb/yr) [3] C1	C2	C3	iC4	C4	iC5	C5	C6	C7
Filters/Coalescers																			
15-358-1A/B	Plant inlet feed filters	0.0138	0.3328	0.0570	0.0231	0.0170	0.0045	0.0028	0.0004	0.0022	5.7559	138.4448	23.6923	9.6090	7.0795	1.8753	1.1631	0.1483	0.8961
15-358-2A/B	Plant feed inlet coalescers	0.0278	0.6694	0.1146	0.0465	0.0342	0.0091	0.0056	0.0007	0.0043	11.5780	278.4810	47.6569	19.3284	14.2404	3.7722	2.3395	0.2983	1.8025
15-358-401	Treated Propane Filter Coalescer	0.0000	0.0180	0.1191	0.0030	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	7.4824	49.5299	1.2571	0.1155	0.0000	0.0000	0.0000	0.0000
15-358-501	Treated gasoline coalescer	0.0000	0.0000	0.0000	0.0000	0.0003	0.0066	0.0044	0.0003	0.0018	0.0000	0.0000	0.0000	0.0015	0.1272	2.7360	1.8138	0.1227	0.7415
15-358-601	n-butane product coalescer	0.0000	0.0000	0.0000	0.0030	0.0718	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	1.2505	29.8621	0.0655	0.0031	0.0000	0.0000
Compressors																			
11-358-1A/B	Ethane	1.5689	74.8634	0.7577	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	18.8264	898.3614	9.0920	0.0005	0.0000	0.0000	0.0000	0.0000	0.0000
11-358-2A/B	Refrigeration	0.0000	1.1632	7.7001	0.1954	0.0180	0.0000	0.0000	0.0000	0.0000	0.0000	4.6530	30.8003	0.7817	0.0719	0.0000	0.0000	0.0000	0.0000
11-358-3	C4 Splitter	0.0000	0.0000	0.0668	5.7284	0.0760	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2672	22.9136	0.3040	0.0000	0.0000	0.0000	0.0000
Emissions [4]		1.57	74.86	7.70	6.00	0.22	0.02	0.01	0.00	0.01	36.16	1,327.42	161.04	55.14	51.80	8.45	5.32	0.57	3.44

[1] C1, C2, and C3 emissions are routed to FLR-5 with a control efficiency of 99% per TCEQ flare guidance.

All other emissions are routed to FLR-5 with a control efficiency of 98% per TCEQ flare guidance.

[2] Controlled Weight Per Hour (lb/hr) = Total Volume Rate (ft^3/hr) x Vapor Density (lb/ft^3) x VOC Component Vapor Mass Fraction x (100-Flare Control Efficiency (%))/100

Filters/Coalescer 15-358-1A/B Controlled C3 Weight Per Hour (lb/hr) = 13 ft^3 / hr | 3.35 lb / ft^3 | 0.13 | 100-99% / 100 = 0.06 lb/hr

[3] Controlled Weight Per Year (lb/yr) = Total Volume (ft^3) x Vapor Density (lb/ft^3) x VOC Component Vapor Mass Fraction x Frequency/Year x (100-Flare Control Efficiency (%))/100

Filters/Coalescer 15-358-1A/B Controlled C3 Weight Per Year (lb/yr) = 51 ft^3 / event | 3.35 lb / ft^3 | 0.13 | 104 events / yr | 100-99% / 100 = 23.69 lb/yr

[4] Hourly emissions are based on the maximum emissions of each of the filters/coalescers and compressors. The annual emissions (lb/yr) are the sum of the speciated emissions of all units.

Liquid Parameters

Unit ID	Description	Hours Per Event (hr/event)	Frequency per Year (event/yr)	ID (ft)	Height (ft)	Total Volume [1] (ft^3/event)	Total Volume Rate [2] (ft^3/hr)	Heel (ft)	Heel Volume [3] (ft^3/event)	Heel Volume Rate (ft^3/hr)	Liquid Density (lb/ft^3)	Component Liquid Mass Fraction [4]: C1	C2	C3	iC4	C4	iC5	C5	C6	C7	Gas Heating Rate [5] (MMBtu/hr)
Filters/Coalescers																					
15-358-1A/B	Plant inlet feed filters	2	104	3	7.25	51	26	0.5	4	2	27.23	0.0064	0.5068	0.2101	0.0803	0.0750	0.0374	0.0281	0.0079	0.0479	0.0041
15-358-2A/B	Plant feed inlet coalescers	2	104	5	5.25	103	52	0.5	10	5	27.23	0.0064	0.5068	0.2101	0.0803	0.0750	0.0374	0.0281	0.0079	0.0479	0.0115
15-358-401	Treated Propane Filter Coalescer	2	104	3	5.25	37	19	0.5	4	2	30.27	0.0000	0.0471	0.9241	0.0256	0.0031	0.0000	0.0000	0.0000	0.0000	0.0042
15-358-501	Treated gasoline coalescer	2	104	2.33	5.25	22	11	0.5	2	1	39.49	0.0000	0.0000	0.0000	0.0000	0.0056	0.3064	0.2712	0.0592	0.3576	0.0043
15-358-601	n-butane product coalescer	2	104	3	5.25	37	19	0.5	4	2	35.62	0.0000	0.0000	0.0000	0.0289	0.9656	0.0052	0.0002	0.0000	0.0000	0.0055
Pumps																					
28-358-1A/B	DC2 Reflux Pumps	2	2	-	-	11.24	6	-	-	-	17.03	0.0125	0.9733	0.0142	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0095
28-358-2A/B	DC3 Reflux Pumps	2	2	-	-	11.24	6	-	-	-	30.27	0.0000	0.0471	0.9241	0.0256	0.0031	0.0000	0.0000	0.0000	0.0000	0.0133
28-358-3A/B	C3 Inject pumps	2	2	-	-	11.24	6	-	-	-	30.27	0.0000	0.0471	0.9241	0.0256	0.0031	0.0000	0.0000	0.0000	0.0000	0.0133
28-358-4A/B	DC4 Reflux pumps	2	2	-	-	11.24	6	-	-	-	35.24	0.0000	0.0000	0.0026	0.2901	0.7033	0.0038	0.0002	0.0000	0.0000	0.0175
28-358-5A/B	Gasoline booster pumps	2	2	-	-	11.24	6	-	-	-	39.49	0.0000	0.0000	0.0000	0.0000	0.0056	0.3064	0.2712	0.0592	0.3576	0.0225
28-358-6A/B	Gasoline injection pumps	2	2	-	-	11.24	6	-	-	-	39.49	0.0000	0.0000	0.0000	0.0000	0.0056	0.3064	0.2712	0.0592	0.3576	0.0225
28-358-7A/B	C4 split bottoms pumps	2	2	-	-	11.24	6	-	-	-	34.22	0.0000	0.0000	0.0095	0.9729	0.0176	0.0000	0.0000	0.0000	0.0000	0.0174
28-358-8A/B	C4 split reflux pumps	2	2	-	-	11.24	6	-	-	-	35.62	0.0000	0.0000	0.0000	0.0289	0.9656	0.0052	0.0002	0.0000	0.0000	0.0176
28-358-9A/B	C4 Split comp K.O. drum pumps	2	2	-	-	11.24	6	-	-	-	34.22	0.0000	0.0000	0.0095	0.9729	0.0176	0.0000	0.0000	0.0000	0.0000	0.0174
28-358-10A/B	iC4 injection pumps	2	2	-	-	11.24	6	-	-	-	34.22	0.0000	0.0000	0.0095	0.9729	0.0176	0.0000	0.0000	0.0000	0.0000	0.0174
28-358-11A/B	nC4 injection pumps	2	2	-	-	11.24	6	-	-	-	35.62	0.0000	0.0000	0.0000	0.0289	0.9656	0.0052	0.0002	0.0000	0.0000	0.0176

[1] Total Volume (ft^3/event) = Pi * (ID (ft) / 2)^2 x Height (ft)

Filters/Coalescer 15-358-1A/B Total Volume (ft^3/event) = π | (3 ft / 2)^2 | 7.25 ft = 51 ft^3/event

[2] Total Volume Rate or Heel Volume Rate (ft^3/hr) = Total Volume or Heel Volume (ft^3/event) / Hours Per Event (hr/event)

Filters/Coalescers 15-358-1A/B Total Volume Rate (ft^3/hr) = 51 ft^3 / event | event / 2 hr = 26 ft^3/hr

[3] Heel Volume (ft^3/event) = Pi * (ID (ft)/2)^2 x Heel (ft)

Filters/Coalescers 15-358-1A/B Heel Volume (ft^3/event) = π | (3 ft / 2)^2 | 0.5 ft = 4 ft^3/event

[4] The mass fraction ratio of n-hexane to n-hexane and higher is 14.2 %

[5] Speciated Gas Heating Rate (MMBtu/hr) = Total Volume or Heel Volume Flow Rate (ft^3/hr) x Component Mass Fraction x Higher Heating Value (Btu/ft^3) x 1 MMBtu / 1,000,000 Btu

Liquid Emissions to FLR-5[1]

		Controlled Weight Per Hour (lb/hr) [1,2,3]									Controlled Weight Per Year (lb/yr) [4,5]								
Unit ID	**Description**	**C1**	**C2**	**C3**	**iC4**	**C4**	**iC5**	**C5**	**C6**	**C7**	**C1**	**C2**	**C3**	**iC4**	**C4**	**iC5**	**C5**	**C6**	**C7**
Filters/Coalescers																			
15-358-1A/B	Plant inlet feed filters	0.0031	0.2439	0.1011	0.0773	0.0722	0.0360	0.0271	0.0076	0.0461	0.6406	50.7247	21.0285	16.0742	15.0132	7.4816	5.6325	1.5878	9.5938
15-358-2A/B	Plant feed inlet coalescers	0.0086	0.6774	0.2808	0.2147	0.2005	0.0999	0.0752	0.0212	0.1281	1.7793	140.9020	58.4126	44.6505	41.7034	20.7821	15.6458	4.4105	26.6494
15-358-401	Treated Propane Filter Coalescer	0.0000	0.0252	0.4943	0.0274	0.0034	0.0000	0.0000	0.0000	0.0000	0.0000	5.2408	102.8228	5.6981	0.6991	0.0000	0.0000	0.0000	0.0000
15-358-501	Treated gasoline coalescer	0.0000	0.0000	0.0000	0.0000	0.0048	0.2587	0.2289	0.0500	0.3019	0.0000	0.0000	0.0000	0.0081	0.9911	53.8109	47.6200	10.3924	62.7934
15-358-601	n-butane product coalescer	0.0000	0.0000	0.0000	0.0364	1.2156	0.0066	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	7.5753	252.8498	1.3695	0.0594	0.0000	0.0000
Pumps																			
28-358-1A/B	DC2 Reflux Pumps	0.0119	0.9312	0.0136	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0478	3.7248	0.0544	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
28-358-2A/B	DC3 Reflux Pumps	0.0000	0.0801	1.5716	0.0871	0.0107	0.0000	0.0000	0.0000	0.0000	0.0000	0.3204	6.2863	0.3484	0.0427	0.0000	0.0000	0.0000	0.0000
28-358-3A/B	C3 Inject pumps	0.0000	0.0801	1.5716	0.0871	0.0107	0.0000	0.0000	0.0000	0.0000	0.0000	0.3204	6.2863	0.3484	0.0427	0.0000	0.0000	0.0000	0.0000
28-358-4A/B	DC4 Reflux pumps	0.0000	0.0000	0.0052	1.1488	2.7848	0.0150	0.0006	0.0000	0.0000	0.0000	0.0000	0.0207	4.5950	11.1393	0.0599	0.0026	0.0000	0.0000
28-358-5A/B	Gasoline booster pumps	0.0000	0.0000	0.0000	0.0002	0.0250	1.3596	1.2032	0.2626	1.5865	0.0000	0.0000	0.0000	0.0008	0.1002	5.4383	4.8127	1.0503	6.3461
28-358-6A/B	Gasoline injection pumps	0.0000	0.0000	0.0000	0.0002	0.0250	1.3596	1.2032	0.2626	1.5865	0.0000	0.0000	0.0000	0.0008	0.1002	5.4383	4.8127	1.0503	6.3461
28-358-7A/B	C4 split bottoms pumps	0.0000	0.0000	0.0182	3.7408	0.0678	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0727	14.9632	0.2712	0.0000	0.0000	0.0000	0.0000
28-358-8A/B	C4 split reflux pumps	0.0000	0.0000	0.0000	0.1158	3.8646	0.0209	0.0009	0.0000	0.0000	0.0000	0.0000	0.0000	0.4631	15.4586	0.0837	0.0036	0.0000	0.0000
28-358-9A/B	C4 Split comp K.O. drum pumps	0.0000	0.0000	0.0182	3.7408	0.0678	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0727	14.9632	0.2712	0.0000	0.0000	0.0000	0.0000
28-358-10A/B	iC4 injection pumps	0.0000	0.0000	0.0182	3.7408	0.0678	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0727	14.9632	0.2712	0.0000	0.0000	0.0000	0.0000
28-358-11A/B	nC4 injection pumps	0.0000	0.0000	0.0000	0.1158	3.8646	0.0209	0.0009	0.0000	0.0000	0.0000	0.0000	0.0000	0.4631	15.4586	0.0837	0.0036	0.0000	0.0000
Emissions [6]		0.01	0.93	1.57	3.74	3.86	1.36	1.20	0.26	1.59	2.47	201.23	195.13	125.12	354.41	94.55	78.59	18.49	111.73

[1] Liquids from maintenance activities will be routed to flare tanks, where resultant vapors will be combusted in the flare.
C1, C2, and C3 emissions are routed to FLR-5 with a control efficiency of 99% per TCEQ flare guidance.
All other emissions are routed to FLR-5 with a control efficiency of 98% per TCEQ flare guidance.

[2] Filters and Coalescers Controlled Weight Per Hour (lb/hr) = Heel Volume Rate (ft^3) x Liquid Density (lb/ft^3) x Component Liquid Mass Fraction x (100-Flare Control Efficiency (%))/100

Filters/Coalescer 15-358-1A/B Controlled C3 Weight Per Hour (lb/hr) = 2 ft3 / hr | 27.23 lb / ft^3 | 0.21 | 100-99% / 100 = 0.1 lb/hr

[3] Pumps Controlled Weight Per Hour (lb/hr) = Total Volume Rate (ft^3/hr) x Liquid Density (lb/ft^3) x Component Liquid Mass Fraction x (100-Flare Control Efficiency (%))/100

Pump 28-358-1A/B C3 Weight Per Hour (lb/hr) = 6 ft3 / hr | 17.03 lb / ft^3 | 0.01 | 1-99% = 0.01 lb/hr

[4] Filters and Coalescers Controlled Weight Per Year (lb/yr) = Heel Volume (ft^3/event) x Liquid Density (lb/ft^3) x Component Liquid Mass Fraction * Frequency Per Year (event/yr) x (100-Flare Control Efficiency (%))/100

Filters/Coalescers 15-358-1A/B Controlled C3 Weight Per Year (lb/yr) = 4 ft3 / event | 27.23 lb / ft^3 | 0.21 | 104 events / yr | 100-99% / 100 = 21.03 lb/yr

[5] Pumps Controlled Weight Per Year (lb/yr) = Total Volume (ft^3) x Liquid Density (lb/ft^3) x Component Liquid Mass Fraction x Frequency/Year x (100-Flare Control Efficiency (%))/100

Pump 28-358-1A/B C3 Weight Per Year (lb/yr) = 11.24 ft3 / event | 17.03 lb / ft^3 | 0.01 | 2 events / yr | 100-99% / 100 = 0.05 lb/yr

[6] Hourly emissions are based on the maximum emissions of each of the filters/coalescers and compressors. The annual emissions (lb/yr) are the sum of the speciated emissions of all units.

Targa Midstream Services LLC - Mont Belvieu Plant
Maintenance Emissions Calculations

Uncontrolled Emissions Sent to Atmosphere Parameters

Unit ID [1]	Description [1]	Hours Per Event (hr/event)	Frequency per Year (event/yr)	ID (ft)	Height (ft)	Total Volume [1] (ft^3/event)	Total Volume Rate [2] (ft^3/hr)	Molar VOC Content [3,4] (lb-mol/yr)	Vapor Mass Fraction [5] C1	C2	C3	iC4	C4	iC5	C5	C6	C7
Filters/Coalescers																	
15-358-1A/B	Plant inlet feed filters	1	104	3	7.25	51	51	0.14	0.0633	0.8119	0.0947	0.0146	0.0107	0.0023	0.0014	0.0002	0.0009
15-358-2A/B	Plant feed inlet coalescers	1	104	5	5.25	103	103	0.28	0.0633	0.8119	0.0947	0.0146	0.0107	0.0023	0.0014	0.0002	0.0009
15-358-401	Treated Propane Filter Coalescer	1	104	3	5.25	37	37	0.10	0.0000	0.1798	0.8117	0.0078	0.0007	0.0000	0.0000	0.0000	0.0000
15-358-501	Treated gasoline coalescer	1	104	2.33	5.25	22	22	0.06	0.0000	0.0000	0.0000	0.0003	0.0291	0.5036	0.3338	0.0189	0.1143
15-358-601	n-butane product coalescer	1	104	3	5.25	37	37	0.10	0.0000	0.0000	0.0000	0.0401	0.9581	0.0017	0.0001	0.0000	0.0000
Pumps																	
28-358-1A/B	DC2 Reflux Pumps	1	2	-	-	11.24	11	0.00	0.0375	0.9559	0.0066	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
28-358-2A/B	DC3 Reflux Pumps	1	2	-	-	11.24	11	0.00	0.0000	0.1798	0.8117	0.0078	0.0007	0.0000	0.0000	0.0000	0.0000
28-358-3A/B	C3 Inject pumps	1	2	-	-	11.24	11	0.00	0.0000	0.1798	0.8117	0.0078	0.0007	0.0000	0.0000	0.0000	0.0000
28-358-4A/B	DC4 Reflux pumps	1	2	-	-	11.24	11	0.00	0.0000	0.0000	0.0104	0.3604	0.6281	0.0011	0.0000	0.0000	0.0000
28-358-5A/B	Gasoline booster pumps	1	2	-	-	11.24	11	0.00	0.0000	0.0000	0.0000	0.0003	0.0291	0.5036	0.3338	0.0189	0.1143
28-358-6A/B	Gasoline injection pumps	1	2	-	-	11.24	11	0.00	0.0000	0.0000	0.0000	0.0003	0.0291	0.5036	0.3338	0.0189	0.1143
28-358-7A/B	C4 split bottoms pumps	1	2	-	-	11.24	11	0.00	0.0000	0.0000	0.0294	0.9578	0.0127	0.0000	0.0000	0.0000	0.0000
28-358-8A/B	C4 split reflux pumps	1	2	-	-	11.24	11	0.00	0.0000	0.0000	0.0000	0.0401	0.9581	0.0017	0.0001	0.0000	0.0000
28-358-9A/B	C4 Split comp K.O. drum pumps	1	2	-	-	11.24	11	0.00	0.0000	0.0000	0.0294	0.9578	0.0127	0.0000	0.0000	0.0000	0.0000
28-358-10A/B	iC4 injection pumps	1	2	-	-	11.24	11	0.00	0.0000	0.0000	0.0294	0.9578	0.0127	0.0000	0.0000	0.0000	0.0000
28-358-11A/B	nC4 injection pumps	1	2	-	-	11.24	11	0.00	0.0000	0.0000	0.0000	0.0401	0.9581	0.0017	0.0001	0.0000	0.0000
Compressors																	
11-358-1A/B	Ethane	1	6	-	-	2,000	2,000	0.32	0.0375	0.9559	0.0066	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
11-358-2A/B	Refrigeration	2	2	-	-	1,200	600	0.06	0.0000	0.1798	0.8117	0.0078	0.0007	0.0000	0.0000	0.0000	0.0000
11-358-3	C4 Splitter	3	2	-	-	1,000	333	0.05	0.0000	0.0000	0.0294	0.9578	0.0127	0.0000	0.0000	0.0000	0.0000

[1] Total Volume (ft^3/event) = Pi * (ID (ft) / 2)^2 x Height (ft)

Filters/Coalescer 15-358-1A/B Total Volume (ft^3/event) = π | (3 ft / 2)^2 | 7.25 ft = 51 ft^3/event

[2] Total Volume Rate or Heel Volume Rate (ft^3/hr) = Total Volume or Heel Volume (ft^3/event) / Hours Per Event (hr/event)

Filters/Coalescers 15-358-1A/B Total Volume Rate (ft^3/hr) = 51 ft^3 / event | event / 1 hr = 51 ft^3/hr

[3] Emission calculations are based on a VOC content of 10,000 ppmv

[4] Molar VOC Content (lb-mol/yr) = (Frequency/Year) / (379.5 scf/lb-mol) x Total Volume (ft^3/event) x VOC Concentration (ppmv) / 1,000,000

Filter/Coalescers 15-358-1A/B Molar VOC Content(lb-mol/yr) = 104 / yr | lb-mol / 379.5 scf | 51 ft3 / event | 10,000 ppmv / 1,000,000 = 0.14 lb-mol/yr

[5] The mass fraction ratio of n-hexane to n-hexane and higher is 14.2 %

Uncontrolled Emissions Sent to Atmosphere

Unit ID	Description	Uncontrolled Weight Per Hour (lb/hr) [1,2] C1	C2	C3	iC4	C4	iC5	C5	C6	C7	Uncontrolled Weight Per Year (lb/yr) [3] C1	C2	C3	iC4	C4	iC5	C5	C6	C7
Filters/Coalescers																				
15-358-1A/B	Plant inlet feed filters	0.1371	3.2967	0.0056	0.0011	0.0008	0.0002	0.0001	0.0000	0.0001	14.2548	342.8530	0.5868	0.1190	0.0877	0.0232	0.0144	0.0018	0.0129
15-358-2A/B	Plant feed inlet coalescers	0.2757	6.6312	0.0113	0.0023	0.0017	0.0004	0.0003	0.0000	0.0002	28.6734	689.6469	1.1803	0.2393	0.1763	0.0467	0.0290	0.0037	0.0260
15-358-401	Treated Propane Filter Coalescer	0.0000	0.5287	0.0350	0.0004	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	54.9862	3.6402	0.0462	0.0042	0.0000	0.0000	0.0000	0.0000
15-358-501	Treated gasoline coalescer	0.0000	0.0000	0.0000	0.0000	0.0010	0.0215	0.0142	0.0010	0.0068	0.0000	0.0000	0.0000	0.0012	0.1039	2.2353	1.4818	0.1003	0.7044
15-358-601	n-butane product coalescer	0.0000	0.0000	0.0000	0.0023	0.0545	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2371	5.6631	0.0124	0.0006	0.0000	0.0000
Pumps		0.0000	0.0000								0.0000	0.0000							
28-358-1A/B	DC2 Reflux Pumps	0.0178	0.8510	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0357	1.7019	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
28-358-2A/B	DC3 Reflux Pumps	0.0000	0.1601	0.0106	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3202	0.0212	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000
28-358-3A/B	C3 Inject pumps	0.0000	0.1601	0.0106	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3202	0.0212	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000
28-358-4A/B	DC4 Reflux pumps	0.0000	0.0000	0.0001	0.0062	0.0108	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0003	0.0124	0.0216	0.0000	0.0000	0.0000	0.0000
28-358-5A/B	Gasoline booster pumps	0.0000	0.0000	0.0000	0.0000	0.0005	0.0108	0.0071	0.0005	0.0034	0.0000	0.0000	0.0000	0.0000	0.0010	0.0215	0.0143	0.0010	0.0068
28-358-6A/B	Gasoline injection pumps	0.0000	0.0000	0.0000	0.0000	0.0005	0.0108	0.0071	0.0005	0.0034	0.0000	0.0000	0.0000	0.0000	0.0010	0.0215	0.0143	0.0010	0.0068
28-358-7A/B	C4 split bottoms pumps	0.0000	0.0000	0.0004	0.0165	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0008	0.0330	0.0004	0.0000	0.0000	0.0000	0.0000
28-358-8A/B	C4 split reflux pumps	0.0000	0.0000	0.0000	0.0007	0.0165	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0014	0.0330	0.0001	0.0000	0.0000	0.0000
28-358-9A/B	C4 Split comp K.O. drum pumps	0.0000	0.0000	0.0004	0.0165	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0008	0.0330	0.0004	0.0000	0.0000	0.0000	0.0000
28-358-10A/B	iC4 injection pumps	0.0000	0.0000	0.0004	0.0165	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0008	0.0330	0.0004	0.0000	0.0000	0.0000	0.0000
28-358-11A/B	nC4 injection pumps	0.0000	0.0000	0.0000	0.0007	0.0165	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0014	0.0330	0.0001	0.0000	0.0000	0.0000
Compressors		0.0000	0.0000								0.0000	0.0000							
11-358-1A/B	Ethane	3.1744	151.4714	0.0153	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	19.0464	908.8282	0.0920	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
11-358-2A/B	Refrigeration	0.0000	8.5483	0.5659	0.0072	0.0007	0.0000	0.0000	0.0000	0.0000	0.0000	34.1932	2.2636	0.0287	0.0026	0.0000	0.0000	0.0000	0.0000
11-358-3	C4 Splitter	0.0000	0.0000	0.0114	0.4890	0.0065	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0684	2.9339	0.0389	0.0000	0.0000	0.0000	0.0000
Emissions [4]		3.1744	151.4714	0.5659	0.4890	0.0545	0.0215	0.0142	0.0010	0.0068	62.0102	2,032.8498	7.8765	3.7200	6.1677	2.3608	1.5543	0.1077	0.7569

[1] Emission calculations for C3 through C7 are based on a VOC content of 10,000 ppmv

[2] Uncontrolled Weight Per Hour for C1 and C2 (lb/hr) = Total Volume Rate (ft^3/hr) / 379.5 (scf/lb-mol) x Vapor Mass Fraction x Component Molecular Weight (lb/lb-mol)

Filter/Coalescers 15-358-1A/B C1 Weight Per Hour (lb/hr) =	51 ft^3 / hr	lb-mol / 379.5 scf	0.063	16.043 lb / lb-mol	=	0.1371 lb/hr

Uncontrolled Weight Per Hour for C3 through C7 (lb/hr) = Total Volume Rate (ft^3/hr) / 379.5 (scf/lb-mol) x VOC Vapor Mass Fraction x Component Molecular Weight (lb/lb-mol) x VOC Concentration (ppmv) / 1,000,000

Filter/Coalescers 15-358-1A/B C3 Weight Per Hour (lb/hr) =	22 ft^3 / hr	lb-mol / 379.5 scf	0.09	44.1 lb / lb-mol	10,000 ppmv / 1,000,000	=	0.0056 lb/hr

[3] Uncontrolled Weight Per Year for C1 and C2 (lb/yr) = Uncontrolled Weight Per Hour (lb/hr) x Hours Per Event {hr/event) x Frequency per Year (event/yr)

Filter/Coalescers 15-358-1A/Bs C3 Weight Per Year (lb/yr) =	0.1371 lb / hr	1 hr / event	104 event / yr	=	14.25 lb/yr

Uncontrolled Weight Per Year (lb/yr) = Component Molecular Weight (lb/lb-mol) x Molar VOC Content (lb-mol/yr) x Vapor Mass Fraction

Filter/Coalescers 15-358-1A/Bs C3 Weight Per Year (lb/yr) =	44.1 lb / lb-mol	0.14 lb-mol / yr	0.09	=	0.59 lb/yr

[4] Hourly emissions are based on the maximum emissions of each of the filters/coalescers and compressors. The annual emissions (lb/yr) are the sum of the speciated emissions of all units.

GHG Emissions

Input Data		
Maximum Hourly Release to Flare [1] =	1,000.00	scf/hr
Annual Releases to Flare [1] =	45,344.45	scf/yr
Higher Heating Value for N_2O [2] =	1.235E-03	MMBtu/scf

[1] Hourly inlet to flare based on the maximum hourly releases among all vapor events and all liquid events. Annual inlet to flare based on the sum of the releases from all vapor events and all liquids events.

[2] Per 40 CFR Part 98, Subpart W, Equation W-40

Global Warming Potentials [1]

CO_2	CH_4	N_2O
1	21	310

[1] Global warming potentials (GWP) obtained from 40 CFR 98 Subpart A Table A-1.

N_2O Emissions

Emission Factor[1,2]		N_2O Emissions[3,4]	
(kg/MMBtu)	(lb/MMBtu)	(lb/hr)	(tpy)
1.00E-04	2.20E-04	2.72E-04	6.17E-06

[1] Per 40 CFR 98 Subpart W, Equation W-40.

[2] Emission factors converted from kg/MMBtu to lb/MMBtu using the following conversion: GHG Emission Factor (lb/MMBtu) = GHG Emission Factor (kg/MMBtu) x 2.2046 (lb/kg)

[3] Hourly Emission Rate for N_2O (lb/hr) = Gas Flowrate (scf/hr) x Subpart W Process Gas HHV (MMBtu/scf) x Emission Factor (lb/MMBtu)

Example N_2O Hourly Emissions (lb/hr) =	1,000.00 scf	1.235E-03 MMBtu	2.20E-04 lb	=	2.72E-04 lb/hr
	hr	scf	MMBtu		

[4] Annual Emission Rate for N_2O (tpy) = Gas Flowrate (scf/yr) x Subpart W Process Gas HHV (MMBtu/scf) x Emission Factor (lb/MMBtu) / 2,000 (lb/ton)

Example N_2O Annual Emission Rate (tpy) =	45,344.45 scf	1.235E-03 MMBtu	2.20E-04 lb	1 ton	=	6.17E-06 tpy
	yr	scf	MMBtu	2,000 lb		

Speciated GHG Emissions - FLR-5

Gas Stream	Compound	Number of Carbon Atoms	DRE [1] (%)	Inlet to Flare [2] (lb/hr)	Inlet to Flare [2] (tpy)	Controlled GHG Emissions [3,4] (lb/hr)	Controlled GHG Emissions [3,4] (tpy)	Converted to CO_2 [5,6] (lb/hr)	Converted to CO_2 [5,6] (tpy)
Emissions to FLR-5	Methane	1	99%	156.89	1.93	1.57	0.02	155.32	1.91
	Ethane	2	99%	7,486.34	76.43	--	--	14,822.96	151.34
	Propane	3	99%	770.01	17.81	--	--	2,286.92	52.89
	Butanes	4	98%	493.20	14.66	--	--	1,933.36	57.47
	Pentanes +	5	98%	220.59	8.03	--	--	1,080.90	39.34

FLR-5 GHG Emissions [7]	(lb/hr)	(tpy)
CO_2	20,279.46	302.95
CH_4	1.57	0.02
N_2O	2.72E-04	6.17E-06
CO_2e	20,312.49	303.36

[1] TCEQ Air Permits Division, Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers, RG-109 (Draft), October 2000.

[2] Hourly inlet to flare based on the maximum hourly releases among all vapor events and all liquid events. Annual inlet to flare based on the sum of the releases from all vapor events and all liquids events.

[3] Controlled GHG Emission (lb/hr) = Inlet to Flare (lb/hr) x (100 - Flare DRE(%))/100

Example Controlled Methane Hourly Emission Rate (lb/hr) = $\frac{156.89 \text{ lb}}{\text{hr}} \times \frac{(100 - 99\%)}{100}$ = 1.57 lb/hr

[4] Controlled GHG Emission (tpy) = Inlet to Flare (tpy) x (100 - Flare DRE(%))/100

Example Controlled Methane Annual Emission Rate (tpy) = $\frac{1.93 \text{ ton}}{\text{yr}} \times (100 - 99\%)$ = 0.02 tpy

[5] Per 40 CFR Part 98.233(z) (Subpart W), for fuel combustion units that combust process vent gas, the following equation is used to estimate the GHG emissions from additional carbon compounds in the fuel.

Hourly Emission Rate for Compounds Converted to CO_2 (lb/hr) = Inlet to Flare (lb/hr) x DRE (%)/100 x Carbon Count (#)

Example Converted Methane Hourly Emission Rate (lb/hr) = $\frac{156.89 \text{ lb}}{\text{hr}} \times \frac{99\%}{100} \times 1$ = 155.32 lb/hr

[6] Annual Emission Rate for Compounds Converted to CO_2 (tpy) = Inlet to Flare (tpy) x DRE (%)/100 x Carbon Count (#)

Example Converted Methane Annual Emission Rate (tpy) = $\frac{1.93 \text{ ton}}{\text{yr}} \times \frac{99\%}{100} \times 1$ = 1.91 tpy

[7] CO_2e Hourly Emission Rate (lb/hr) = CO_2 Emission Rate (lb/hr) x CO_2 GWP + CH_4 Emission Rate (lb/hr) x CH_4 GWP + N_2O Emission Rate (lb/hr) x N_2O GWP

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{20{,}279 \text{ lb}}{\text{hr}} \times 1 + \frac{1.57 \text{ lb}}{\text{hr}} \times 21 + \frac{2.72\text{E-04 lb}}{\text{hr}} \times 310$ = 20,312.49 lb/hr

Speciated GHG Emissions - Vented to Atmosphere

Gas Stream	Compound	Emissions [1] (lb/hr)	Emissions [1] (tpy)	CO_2e [2] (lb/hr)	CO_2e [2] (tpy)
Emissions to Atmosphere	Methane	3.17	0.03	66.66	0.65

[1] GHG Emissions (tpy) = Uncontrolled Weight Per Year (lb/yr) / 2000 lb/ton

Example Controlled Methane Annual Emission Rate (tpy) = $\frac{62.01 \text{ lb}}{\text{yr}} \times \frac{1 \text{ ton}}{2{,}000 \text{ lb}}$ = 0.03 tpy

[2] CO_2e Hourly Emission Rate (lb/hr) = CH_4 Emission Rate (lb/hr) x CH_4 GWP

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{3.17 \text{ lb}}{\text{hr}} \times 21$ = 66.66 lb/hr

Targa Midstream Services LLC - Mont Belvieu Plant
Startup Emissions Sent to Flare Calculations

FLR-5 Emission Factors [1]

Units	CO	NO_x	C1, C2, and C3 Flare Destruction Efficiency	C4+ Flare Destruction Efficiency
lb/MMBtu	0.2755	0.138	-	-
%	-	-	99%	98%

[1] Flare Emissions factors are from TCEQ Air Permits Division, *Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers,* RG-109 (Draft), October 2000, Table 4 (other, high Btu).

Start-up Emissions Summary

FIN	EPN	Source Name	Hourly Emissions (lb/hr) VOC [1]	NO_x [2]	CO [2]	Annual Emissions (tpy) VOC [1]	NO_x [3]	CO [3]
Startup	FLR-5	Startup Emissions to FLR-5	48.01	1.23	2.45	0.51	0.03	0.05

[1] VOC emissions calculated below.
[2] Hourly emissions of NO_x and CO based on the maximum hourly heating rate among all events.
Hourly Emissions of NO_x or CO (lb/hr) = Emission Factor (lb/MMBtu) x Gas Heating Rate (MMBtu/hr)

Hourly Emissions of NO_x (lb/hr) = 0.138 lb / MMBtu | 4.42 MMBtu / hr = 1.23 lb/hr

[3] Annual Emissions (tpy) = Emission Factor (lb/MMBtu) x Σ (Hours per Event [hr/event] x Frequency per Year [event/yr] x Gas Heating Rate [MMBtu/hr])

Gas Heating Rates [1]

Speciated Gas	Higher Heating Value (Btu/ft^3)
C1	912
C2	1,699
C3	2,385
iC4	3105
C4	3,123
iC5	3,705
C5	3,714
C6	4,415
C7	4,415

[1] Per Table 5-7 of *Combined Heating, Cooling & Power Handbook: Technologies & Applications,* by Neil Petchers (2003)

Targa Midstream Services LLC - Mont Belvieu Plant
Startup Emissions Sent to Flare Calculations

Startup Parameters for Emissions to FLR-5

Unit ID	Description	Hours Per Event (hr/event)	Frequency per Year (event/yr)	ID (ft)	Height (ft)	Total Volume[1] (ft^3/event)	Total Volume Rate[2] (ft^3/hr)	Vapor Density (lb/ft^3)	Vapor Mass Fraction[3] C1	C2	C3	iC4	C4	iC5	C5	C6	C7+	Gas Heating Rate[4] (MMBtu/hr)
Pressure Vessels																		
31-358-1 Deeth	DC2	12	1	16	126	28,551	2,379	3.35	0.0323	0.7766	0.1329	0.0269	0.0199	0.0053	0.0033	0.0004	0.0025	4.42
30-358-1	DC2 Reflux Accum	12	1	10	50	4,712	393	7.72	0.0203	0.9699	0.0098	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.66
30-358-4	C2 Comp suct scrub	6	1	7	10	548	91	7.72	0.0203	0.9699	0.0098	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.15
30-358-6	Refrig comp suct scrub	6	1	8	10	905	151	1.50	0.0000	0.1297	0.8584	0.0109	0.0010	0.0000	0.0000	0.0000	0.0000	0.35
30-358-7	Refrig Accumulator	12	1	8	24	1,608	134	1.50	0.0000	0.1297	0.8584	0.0109	0.0010	0.0000	0.0000	0.0000	0.0000	0.31
31-358-4	DC3	12	1	13	114	16,857	1,405	0.83	0.0000	0.1079	0.6462	0.0800	0.1290	0.0183	0.0122	0.0009	0.0055	3.54
30-358-9	DC3 Reflux Accum	12	1	10	40	3,927	327	1.50	0.0000	0.1297	0.8584	0.0109	0.0010	0.0000	0.0000	0.0000	0.0000	0.75
30-358-401A/B	C3 COS Reactors	6	1	6	30	1,018	170	1.50	0.0000	0.1297	0.8584	0.0109	0.0010	0.0000	0.0000	0.0000	0.0000	0.39
30-358-402A/B	C3 H2S Reactors	6	1	7	34	1,578	263	1.50	0.0000	0.1297	0.8584	0.0109	0.0010	0.0000	0.0000	0.0000	0.0000	0.61
31-358-5	DC4	12	1	10	98	7,620	635	0.33	0.0000	0.0000	0.0069	0.3097	0.5389	0.0728	0.0480	0.0034	0.0203	2.04
30-358-10	DC4 Reflux accum	12	1	9	30	2,185	182	0.46	0.0000	0.0000	0.0079	0.3612	0.6294	0.0014	0.0000	0.0000	0.0000	0.57
31-358-6	C4 Splitter	12	1	12	212	25,334	2,111	0.46	0.0000	0.0000	0.0079	0.3612	0.6294	0.0014	0.0000	0.0000	0.0000	6.57
30-358-11	C4 Splitter comp K.O.	12	1	7	16	747	62	0.59	0.0000	0.0000	0.0225	0.9647	0.0128	0.0000	0.0000	0.0000	0.0000	0.19
30-358-12	C4 Splitter Reflux accum	12	1	9	40	2,752	229	0.46	0.0000	0.0000	0.0225	0.9647	0.0128	0.0000	0.0000	0.0000	0.0000	0.71
30-358-501A/B/C	Gasoline treaters	6	1	8	16	3,619	603	0.12	0.0000	0.0000	0.0000	0.0003	0.0230	0.4936	0.3272	0.0221	0.1338	2.30
30-358-502A/B/C	Caustic separators	6	1	6	20	2,205	368	0.12	0.0000	0.0000	0.0000	0.0003	0.0230	0.4936	0.3272	0.0221	0.1338	1.40
30-358-601A/B	Caustic Contactors	6	1	12	50	14,024	2,337	0.12	0.0000	0.0000	0.0000	0.0003	0.0230	0.4936	0.3272	0.0221	0.1338	8.89
30-358-602A/B	Caustic Settlers	6	1	6	30	2,036	339	0.12	0.0000	0.0000	0.0000	0.0003	0.0230	0.4936	0.3272	0.0221	0.1338	1.29
Pipelines																		
	RP	6	1	1	3,800	2,487	415	3.35	0.0323	0.7766	0.1329	0.0269	0.0199	0.0053	0.0033	0.0004	0.0025	0.77
	C2	6	1	1	3,800	2,487	415	7.72	0.0203	0.9699	0.0098	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.70
	C3	6	1	1	3,800	1,990	332	1.50	0.0000	0.1297	0.8584	0.0109	0.0010	0.0000	0.0000	0.0000	0.0000	0.76
	iC4	6	1	1	3,800	1,492	249	0.59	0.0000	0.0000	0.0225	0.9647	0.0128	0.0000	0.0000	0.0000	0.0000	0.77
	nC4	6	1	1	3,800	1,492	249	0.40	0.0000	0.0000	0.0000	0.0401	0.9576	0.0021	0.0001	0.0000	0.0000	0.78
	C5+	6	1	1	3,800	1,492	249	0.12	0.0000	0.0000	0.0000	0.0003	0.0230	0.4936	0.3272	0.0221	0.1338	0.95
Compressors																		
11-358-1A/B	Ethane	1	1	-	-	2,000	2,000	7.72	0.0203	0.9699	0.0098	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	3.38
11-358-2A/B	Refrigeration	2	1	-	-	1,200	600	1.50	0.0000	0.1297	0.8584	0.0109	0.0010	0.0000	0.0000	0.0000	0.0000	1.38
11-358-3	C4 Splitter	2	1	-	-	1,000	500	0.59	0.0000	0.0000	0.0225	0.9647	0.0128	0.0000	0.0000	0.0000	0.0000	1.54

[1] Total Volume (ft^3/event) = Pi * (ID (ft) / 2)^2 x Height (ft)

Pressure Vessel 31-358-1 Deeth C3 Total Volume (ft^3/event) = π | (16 ft / 2)^2 | 126 ft = 28,551 ft^3/event

[2] Total Volume Rate (ft^3/hr) = Total Volume (ft^3/event) / Hours Per Event (hr/event)

Pressure Vessel 31-358-1 Deeth C3 Total Volume Rate (ft^3/hr) = (28,551 ft3 / event) | (event / 12 hr) = 2,379 ft3/hr

[3] The mass fraction ratio of n-hexane to n-hexane and higher is 14.2 %

[4] Speciated Gas Heating Rate (MMBtu/hr) = Gas Volume Flow Rate (ft^3/hr) x Component Mass Fraction x Higher Heating Value (Btu/ft^3) x 1 MMBtu / 1,000,000 Btu

Targa Midstream Services LLC - Mont Belvieu Plant
Startup Emissions Sent to Flare Calculations

Startup Emissions to FLR-5

			Controlled Weight Per Hour (lb/hr) [1]									Controlled Weight Per Year (lb/yr) [2]								
Unit ID	**Description**	**Emission Groups**	**C1**	**C2**	**C3**	**iC4**	**C4**	**iC5**	**C5**	**C6**	**C7**	**C1**	**C2**	**C3**	**iC4**	**C4**	**iC5**	**C5**	**C6**	**C7**
Pressure Vessels																				
31-358-1 Deeth	DC2	A	2.57	61.80	10.58	4.29	3.16	0.84	0.52	0.07	0.40	30.83	741.64	126.92	51.47	37.92	10.05	6.23	0.79	4.80
30-358-1	DC2 Reflux Accum	A	0.62	29.40	0.30	1.60E-05	3.68E-07	3.68E-07	3.68E-07	5.22E-08	3.16E-07	7.39	352.79	3.57	1.92E-04	4.41E-06	4.41E-06	4.41E-06	6.27E-07	3.79E-06
30-358-4	C2 Comp suct scrub	A	0.14	6.83	0.07	3.71E-06	8.55E-08	8.55E-08	8.55E-08	1.21E-08	7.33E-08	0.86	40.99	0.41	2.23E-05	5.13E-07	5.13E-07	5.13E-07	7.28E-08	4.40E-07
30-358-6	Refrig comp suct scrub	B	1.61E-08	0.29	1.94	0.05	4.51E-03	7.45E-08	7.45E-08	1.06E-08	6.40E-08	9.65E-08	1.75	11.61	0.29	0.03	4.47E-07	4.47E-07	6.35E-08	3.84E-07
30-358-7	Refrig Accumulator	B	1.43E-08	0.26	1.72	0.04	4.01E-03	6.63E-08	6.63E-08	9.41E-09	5.68E-08	1.72E-07	3.12	20.64	0.52	0.05	7.95E-07	7.95E-07	1.13E-07	6.82E-07
31-358-4	DC3	C	7.97E-08	1.26	7.55	1.87	3.02	0.43	0.29	0.02	0.13	9.57E-07	15.13	90.65	22.44	36.20	5.12	3.43	0.26	1.55
30-358-9	DC3 Reflux Accum	C	3.49E-08	0.63	4.20	0.11	9.80E-03	1.62E-07	1.62E-07	2.30E-08	1.39E-07	4.19E-07	7.61	50.40	1.28	0.12	1.94E-06	1.94E-06	2.76E-07	1.67E-06
30-358-401A/B	C3 COS Reactors	D	1.81E-08	0.33	2.18	0.06	5.08E-03	8.39E-08	8.39E-08	1.19E-08	7.19E-08	1.09E-07	1.97	13.06	0.33	0.03	5.03E-07	5.03E-07	7.14E-08	4.32E-07
30-358-402A/B	C3 H2S Reactors	D	2.80E-08	0.51	3.37	0.09	7.87E-03	1.30E-07	1.30E-07	1.85E-08	1.12E-07	1.68E-07	3.06	20.25	0.51	0.05	7.80E-07	7.80E-07	1.11E-07	6.69E-07
31-358-5	DC4	E	6.94E-25	1.62E-09	0.01	1.28	2.23	0.30	0.20	0.01	0.08	8.33E-24	1.95E-08	0.17	15.34	26.70	3.61	2.38	0.17	1.00
30-358-10	DC4 Reflux accum	E	3.02E-25	3.02E-25	6.56E-03	0.60	1.04	2.32E-03	7.66E-05	5.84E-12	3.53E-11	3.62E-24	3.62E-24	0.08	7.19	12.53	0.03	9.19E-04	7.00E-11	4.23E-10
31-358-6	C4 Splitter	E	3.50E-24	3.50E-24	0.08	6.95	12.11	0.03	8.88E-04	6.77E-11	4.09E-10	4.20E-23	4.20E-23	0.91	83.38	145.30	0.32	0.01	8.12E-10	4.91E-09
30-358-11	C4 Splitter comp K.O.	E	1.35E-25	1.35E-25	8.31E-03	0.71	9.46E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.61E-24	1.61E-24	0.10	8.55	0.11	0.00E+00	0.00E+00	0.00E+00	0.00E+00
30-358-12	C4 Splitter Reflux accum	E	3.81E-25	3.81E-25	0.02	2.02	0.03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.57E-24	4.57E-24	0.28	24.19	0.32	0.00E+00	0.00E+00	0.00E+00	0.00E+00
30-358-501A/B/C	Gasoline treaters	E	0.00E+00	1.98E-24	6.14E-11	3.78E-04	0.03	0.71	0.47	0.03	0.19	0.00E+00	1.19E-23	3.68E-10	2.27E-03	0.20	4.24	2.81	0.19	1.15
30-358-502A/B/C	Caustic separators	E	0.00E+00	1.21E-24	3.74E-11	2.30E-04	0.02	0.43	0.29	0.02	0.12	0.00E+00	7.24E-24	2.24E-10	1.38E-03	0.12	2.58	1.71	0.12	0.70
30-358-601A/B	Caustic Contactors	E	0.00E+00	7.68E-24	2.38E-10	1.46E-03	0.13	2.74	1.82	0.12	0.74	0.00E+00	4.61E-23	1.43E-09	8.79E-03	0.76	16.43	10.89	0.74	4.45
30-358-602A/B	Caustic Settlers	E	0.00E+00	1.11E-24	3.45E-11	2.13E-04	0.02	0.40	0.26	0.02	0.11	0.00E+00	6.69E-24	2.07E-10	1.28E-03	0.11	2.39	1.58	0.11	0.65
Pipelines																				
	RP	-	0.45	10.77	1.84	0.75	0.55	0.15	0.09	0.01	0.07	2.69	64.60	11.06	4.48	3.30	0.88	0.54	0.07	0.42
	C2	-	0.65	31.03	0.31	1.69E-05	3.88E-07	3.88E-07	3.88E-07	5.51E-08	3.33E-07	3.90	186.19	1.88	1.01E-04	2.33E-06	2.33E-06	2.33E-06	3.31E-07	2.00E-06
	C3	-	3.54E-08	0.64	4.26	0.11	9.93E-03	1.64E-07	1.64E-07	2.33E-08	1.41E-07	2.12E-07	3.86	25.53	0.65	0.06	9.83E-07	9.83E-07	1.40E-07	8.44E-07
	iC4	-	5.38E-25	5.38E-25	0.03	2.85	0.04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.23E-24	3.23E-24	0.20	17.10	0.23	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	nC4	-	0.00E+00	0.00E+00	0.00E+00	0.08	1.92	4.22E-03	2.01E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.48	11.55	0.03	1.21E-03	0.00E+00	0.00E+00
	C5+	-	0.00E+00	8.17E-25	2.53E-11	1.56E-04	0.01	0.29	0.19	0.01	0.08	0.00E+00	4.90E-24	1.52E-10	9.35E-04	0.08	1.75	1.16	0.08	0.47
Compressors																				
11-358-1A/B	Ethane	-	3.14	149.73	1.52	8.14E-05	1.87E-06	1.87E-06	1.87E-06	2.66E-07	1.61E-06	3.14	149.73	1.52	8.14E-05	1.87E-06	1.87E-06	1.87E-06	2.66E-07	1.61E-06
11-358-2A/B	Refrigeration	-	6.40E-08	1.16	7.70	0.20	0.02	2.97E-07	2.97E-07	4.21E-08	2.54E-07	1.28E-07	2.33	15.40	0.39	0.04	5.93E-07	5.93E-07	8.42E-08	5.09E-07
11-358-3	C4 Splitter	-	1.08E-24	1.08E-24	0.07	5.73	0.08	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.16E-24	2.16E-24	0.13	11.46	0.15	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Emissions [3]			3.33	149.73	11.75	11.56	15.61	4.60	3.03	0.21	1.24	48.81	1,574.77	394.78	250.10	275.96	47.42	30.75	2.51	15.19

[1] Controlled Weight Per Hour (lb/hr) = Total Volume Rate (ft3/hr) x Vapor Density (lb/ft3) x Component Vapor Mass Fraction x (100-(Flare Destruction Factor (%))/100

Pressure Vessel 31-358-1 Deeth C3 Weight Per Hour (lb/hr) = $\frac{2{,}379\ ft3}{hr} \times \frac{3.35\ lb}{ft^3} \times 0.13 \times \frac{100-99\%}{100}$ = 10.58 lb/hr

[2] Controlled Weight Per Year (lb/yr) = Total Volume (ft3) x Vapor Density (lb/ft3) x Component Vapor Mass Fraction x Frequency/Year x (100-(Flare Destruction Factor (%))/100

Pressure Vessel 31-358-1 Deeth C3 Weight Per Year (lb/yr) = $28{,}551\ ft3 \times \frac{3.35\ lb}{ft^3} \times 0.13 \times \frac{1\ event}{yr} \times \frac{100-99\%}{100}$ = 126.92 lb/yr

[3] Each of the pipelines, compressors, and pressure vessels groups occur at separate instances. Therefore, hourly emissions are based on the maximum emissions for the sum of the emissions of Group A, B, C, D, E and each of the remaining units. The annual emissions (lb/yr) are the sum of the speciated emissions of all units.

GHG Emissions

Input Data		
Maximum Hourly Release to Flare [1] =	2,379.23	scf/hr
Annual Releases to Flare [1] =	135,865.64	scf/yr
Higher Heating Value for N_2O [2] =	1.235E-03	MMBtu/scf

[1] Hourly inlet to flare based on the maximum hourly releases among all events. Annual inlet to flare based on the sum of the releases from all events.
[2] Per 40 CFR Part 98, Subpart W, Equation W-40

Global Warming Potentials [1]

CO_2	CH_4	N_2O
1	21	310

[1] Global warming potentials (GWP) obtained from 40 CFR 98 Subpart A Table A-1.

N_2O Emissions

Emission Factor[1,2]		N_2O Emissions[3,4]	
(kg/MMBtu)	(lb/MMBtu)	(lb/hr)	(tpy)
1.00E-04	2.20E-04	6.48E-04	1.85E-05

[1] Per 40 CFR 98 Subpart W, Equation W-40.
[2] Emission factors converted from kg/MMBtu to lb/MMBtu using the following conversion: GHG Emission Factor (lb/MMBtu) = GHG Emission Factor (kg/MMBtu) x 2.2046 (lb/kg)
[3] Hourly Emission Rate for N_2O (lb/hr) = Gas Flowrate (scf/hr) x Subpart W Process Gas HHV (MMBtu/scf) x Emission Factor (lb/MMBtu)

Example N_2O Hourly Emissions (lb/hr) = $\frac{2,379.23 \text{ scf}}{\text{hr}} \times \frac{1.235\text{E-03 MMBtu}}{\text{scf}} \times \frac{2.20\text{E-04 lb}}{\text{MMBtu}}$ = 6.48E-04 lb/hr

[4] Annual Emission Rate for N_2O (tpy) = Gas Flowrate (scf/yr) x Subpart W Process Gas HHV (MMBtu/scf) x Emission Factor (lb/MMBtu) / 2,000 (lb/ton)

Example N_2O Annual Emission Rate (tpy) = $\frac{135,865.64 \text{ scf}}{\text{yr}} \times \frac{1.235\text{E-03 MMBtu}}{\text{scf}} \times \frac{2.20\text{E-04 lb}}{\text{MMBtu}} \times \frac{1 \text{ ton}}{2,000 \text{ lb}}$ = 1.85E-05 tpy

Speciated GHG Emissions - FLR-5

Gas Stream	Compound	Number of Carbon Atoms	DRE [1] (%)	Inlet to Flare [2] (lb/hr)	Inlet to Flare [2] (tpy)	Controlled GHG Emissions[3,4] (lb/hr)	Controlled GHG Emissions[3,4] (tpy)	Converted to CO_2 [5,6] (lb/hr)	Converted to CO_2 [5,6] (tpy)
Emissions to FLR-5	Methane	1	99%	332.88	2.44	3.33	0.02	329.55	2.42
	Ethane	2	99%	14,972.69	78.74	--	--	29,645.93	155.90
	Propane	3	99%	1,175.37	19.74	--	--	3,490.85	58.63
	Butanes	4	98%	1,358.50	13.15	--	--	5,325.33	51.55
	Pentanes +	5	98%	454.22	2.40	--	--	2,225.67	11.75

FLR-5 GHG Emissions [7]	(lb/hr)	(tpy)
CO_2	41,017.32	280.24
CH_4	3.33	0.02
N_2O	6.48E-04	1.85E-05
CO_2e	41,087.42	280.76

[1] TCEQ Air Permits Division, Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers, RG-109 (Draft), October 2000.
[2] Inlet to flare based on the maximum uncontrolled hourly and annual releases.
[3] Controlled GHG Emission (lb/hr) = Inlet to Flare (lb/hr) x (100 - Flare DRE (%))/100

Example Controlled Methane Hourly Emission Rate (lb/hr) = $\frac{332.88 \text{ lb}}{\text{hr}} \times \frac{(100 - 99\%)}{100}$ = 3.33 lb/hr

[4] Controlled GHG Annual Rate (tpy) = Inlet to Flare (tpy) x (100 - Flare DRE (%))/100

Example Controlled Methane Annual Emission Rate (tpy) = $\frac{2.44 \text{ ton}}{\text{yr}} \times \frac{(100 - 99\%)}{100}$ = 0.02 tpy

[5] Per 40 CFR Part 98.233(z) (Subpart W), for fuel combustion units that combust process vent gas, the following equation is used to estimate the GHG emissions from additional carbon compounds in the fuel.
Hourly Emission Rate for Compounds Converted to CO_2 (lb/hr) = Inlet to Flare (lb/hr) x DRE (%)/100 x Carbon Count (#)

Example Converted Methane Hourly Emission Rate (lb/hr) = $\frac{332.88 \text{ lb}}{\text{hr}} \times \frac{99\ \%}{100} \times 1$ = 329.55 lb/hr

[6] Annual Emission Rate for Compounds Converted to CO_2 (tpy) = Inlet to Flare (tpy) x DRE (%)/100 x Carbon Count (#)

Example Converted Methane Annual Emission Rate (tpy) = $\frac{2.44 \text{ ton}}{\text{yr}} \times \frac{99\ \%}{100} \times 1$ = 2.42 tpy

[7] CO_2e Hourly Emission Rate (lb/hr) = CO_2 Emission Rate (lb/hr) x CO_2 GWP + CH_4 Emission Rate (lb/hr) x CH_4 GWP + N_2O Emission Rate (lb/hr) x N_2O GWP

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{41,017.32 \text{ lb}}{\text{hr}} \times 1 + \frac{3.33 \text{ lb}}{\text{hr}} \times 21 + \frac{6.48\text{E-04 lb}}{\text{hr}} \times 310$ = 41,087.42 lb/hr

FLR-5 Emission Factors [1]

Units	CO	NO_x	C1, C2, and C3 Flare Destruction Efficiency	C4+ Flare Destruction Efficiency
lb/MMBtu	0.2755	0.138	-	-
%	-	-	99%	98%

[1] Flare Emissions factors are from TCEQ Air Permits Division, *Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers,* RG-109 (Draft), October 2000, Table 4 (other, high Btu).

Shutdown FLR-5 Emissions Summary

FIN	EPN	Source Name	Hourly Emissions (lb/hr) VOC [1]	NO_x [2]	CO [2]	Annual Emissions (tpy) VOC [1]	NO_x [3]	CO [3]
Shutdown	FLR-5	Shutdown Emissions to FLR-5	43.68	2.35	4.69	0.99	0.03	0.05

[1] VOC missions calculated below.
[2] Hourly emissions of NO_x and CO based on the maximum heating rate among the sum of the heating rates for Group F, G, H, I, J, K, L, and each of the remaining units.
Hourly Emissions of NO_x or CO (lb/hr) = Emission Factor (lb/MMBtu) x Gas Heating Rate (MMBtu/hr)

$$\text{Hourly Emissions of } NO_x \text{ (lb/hr)} = \frac{0.138 \text{ lb}}{\text{MMBtu}} \times \frac{6.57 \text{ MMBtu}}{\text{hr}} = 2.35 \text{ lb/hr}$$

[3] NO_x and CO Annual Emissions (tpy) =Flare Emissions Factor (lb/dscf) x Sum of the Product (Total Volume of Emissions (ft^3/event) x Total Frequency (1/yr)) Per Each Equipment x 1 ton / 2,000 lb

Gas Heating Rate [1]

Speciated Gas	Higher Heating Value (Btu/ft^3)
C1	912
C2	1,699
C3	2,385
iC4	3105
C4	3,123
iC5	3,705
C5	3,714
C6	4,415
C7	4,415

[1] Per Table 5-7 of *Combined Heating, Cooling & Power Handbook: Technologies & Applications,* by Neil Petchers (2003)

Shutdown Liquid Parameters Sent to FLR-5

Unit ID	Description	Hours Per Event (hr/event)	Frequency per Year (event/yr)	ID (ft)	Height (ft)	Total Volume [1] (ft^3/event)	Total Volume Rate [2] (ft^3/hr)	Heel (ft)	Heel Volume [3] (ft^3/event)	Heel Volume Rate [2] (ft^3/hr)	Liquid Density (lb/ft^3)	Component Liquid Mass Fraction [4] C1	C2	C3	iC4	C4	iC5	C5	C6	C7	Gas Heating Rate [4] (MMBtu/hr)
Pressure Vessels																					
31-358-1 Deeth	DC2	12	1	16	126	28,551	2,379	2	402	34	27.23	6.40E-03	0.51	0.21	0.08	0.08	0.04	0.03	7.93E-03	0.05	0.0785
30-358-1	DC2 Reflux Accum	12	1	10	50	4,712	393	0.5	39	3	17.03	0.01	0.97	0.01	4.98E-07	1.26E-08	3.56E-13	1.35E-14	1.81E-20	1.09E-19	0.0056
30-358-4	C2 Comp suct scrub	12	1	6.5	10	548	46	0.5	17	1	17.03	0.01	0.97	0.01	4.98E-07	1.26E-08	3.56E-13	1.35E-14	1.81E-20	1.09E-19	0.0023
30-358-6	Refrig comp suct scrub	12	1	8	10	905	75	0.5	25	2	30.27	6.01E-10	0.05	0.92	0.03	3.14E-03	1.13E-07	1.13E-07	1.60E-08	9.69E-08	0.0050
30-358-7	Refrig Accumulator	12	1	8	24	1,608	134	0.5	25	2	30.27	6.01E-10	0.05	0.92	0.03	3.14E-03	1.13E-07	1.13E-07	1.60E-08	9.69E-08	0.0050
31-358-4	DC3	12	1	13	114	16,857	1,405	2	265	22	34.32	2.43E-10	0.02	0.37	0.11	0.24	0.08	0.07	0.02	0.09	0.0673
30-358-9	DC3 Reflux Accum	12	1	10	40	3,927	327	0.5	39	3	30.27	6.01E-10	0.05	0.92	0.03	3.14E-03	1.13E-07	1.13E-07	1.60E-08	9.69E-08	0.0078
30-358-401A/B	C3 COS Reactors	6	1	6	30	1,018	170	0.5	14	2	30.27	6.01E-10	0.05	0.92	0.03	3.14E-03	1.13E-07	1.13E-07	1.60E-08	9.69E-08	0.0056
30-358-402A/B	C3 H2S Reactors	6	1	7	34	1,578	263	0.5	19	3	30.27	6.01E-10	0.05	0.92	0.03	3.14E-03	1.13E-07	1.13E-07	1.60E-08	9.69E-08	0.0076
31-358-5	DC4	12	1	9.5	98	7,620	635	2	142	12	37.05	3.82E-27	4.82E-11	1.49E-03	0.17	0.40	0.13	0.12	0.03	0.15	0.0413
30-358-10	DC4 Reflux accum	12	1	8.5	30	2,185	182	0.5	28	2	35.24	6.71E-27	8.47E-11	2.62E-03	0.29	0.70	3.78E-03	1.64E-04	3.81E-11	2.30E-10	0.0074
31-358-6	C4 Splitter	12	1	12	212	25,334	2,111	2	226	19	35.24	6.71E-27	8.47E-11	2.62E-03	0.29	0.70	3.78E-03	1.64E-04	3.81E-11	2.30E-10	0.0588
30-358-11	C4 Splitter comp K.O.	12	1	6.5	16	747	62	0.5	17	1	34.22	2.43E-26	3.06E-10	9.46E-03	0.97	0.02	8.82E-17	1.29E-21	1.76E-31	1.06E-30	0.0043
30-358-12	C4 Splitter Reflux accum.	12	1	8.5	40	2,752	229	0.5	28	2	34.22	2.43E-26	3.06E-10	9.46E-03	0.97	0.02	8.82E-17	1.29E-21	1.76E-31	1.06E-30	0.0073
30-358-501A/B/C	Gasoline treaters	12	1	8	16	3,619	302	0.5	25	2	39.49	2.08E-31	5.24E-26	5.88E-12	4.59E-05	5.64E-03	0.31	0.27	0.06	0.36	0.0084
30-358-502A/B/C	Caustic separators	12	1	6	20	2,205	184	0.5	14	1	39.49	2.08E-31	5.24E-26	5.88E-12	4.59E-05	5.64E-03	0.31	0.27	0.06	0.36	0.0047
30-358-601A/B	Caustic Contactors	12	1	12	50	14,024	1,169	0.5	57	5	39.49	2.08E-31	5.24E-26	5.88E-12	4.59E-05	5.64E-03	0.31	0.27	0.06	0.36	0.0188
30-358-602A/B	Caustic Settlers	12	1	6	30	2,036	170	0.5	14	1	39.49	2.08E-31	5.24E-26	5.88E-12	4.59E-05	5.64E-03	0.31	0.27	0.06	0.36	0.0047
Pipelines																					
	RP	12	1	0.83	3,800	2,487	207	0.05	124	10	27.23	6.40E-03	0.51	0.21	0.08	0.08	0.04	0.03	7.93E-03	0.05	0.0243
	C2	12	1	0.83	3,800	2,487	207	0.05	124	10	17.03	0.01	0.97	0.01	4.98E-07	1.26E-08	3.56E-13	1.35E-14	1.81E-20	1.09E-19	0.0176
	C3	12	1	0.67	3,800	1,990	166	0.05	99	8	30.27	6.01E-10	0.05	0.92	0.03	3.14E-03	1.13E-07	1.13E-07	1.60E-08	9.69E-08	0.0197
	iC4	12	1	0.5	3,800	1,492	124	0.05	75	6	34.22	2.43E-26	3.06E-10	9.46E-03	0.97	0.02	8.82E-17	1.29E-21	1.76E-31	1.06E-30	0.0193
	nC4	12	1	0.5	3,800	1,492	124	0.05	75	6	35.62	2.76E-31	5.17E-31	1.27E-19	0.03	0.97	5.23E-03	2.27E-04	5.26E-11	3.18E-10	0.0194
	C5+	12	1	0.5	3,800	1,492	124	0.05	75	6	39.49	2.08E-31	5.24E-26	5.88E-12	4.59E-05	5.64E-03	0.31	0.27	0.06	0.36	0.0249
Filters/Coalescers																					
15-358-1A/B	Plant inlet feed filters	2	1	3	7.25	51	26	0.5	4	2	27.23	6.40E-03	0.51	0.21	0.08	0.08	0.04	0.03	7.93E-03	0.05	0.0041
15-358-2A/B	Plant feed inlet coalescers	2	1	5	5.25	103	52	0.5	10	5	27.23	6.40E-03	0.51	0.21	0.08	0.08	0.04	0.03	7.93E-03	0.05	0.0115
15-358-401	Treated Propane Filter Coalescer	2	1	3	5.25	37	19	0.5	4	2	30.27	6.01E-10	0.05	0.92	0.03	3.14E-03	1.13E-07	1.13E-07	1.60E-08	9.69E-08	0.0042
15-358-501	Treated gasoline coalescer	2	1	2.33	5.25	22	11	0.5	2	1	39.49	2.08E-31	5.24E-26	5.88E-12	4.59E-05	5.64E-03	0.31	0.27	0.06	0.36	0.0043
15-358-601	n-butane product coalescer	2	1	3	5.25	37	19	0.5	4	2	35.62	2.76E-31	5.17E-31	1.27E-19	0.03	0.97	5.23E-03	2.27E-04	5.26E-11	3.18E-10	0.0055
Pumps																					
28-358-1A/B	DC2 Reflux Pumps	2	1	-	-	11.24	6	-	-	-	17.03	0.01	0.97	0.01	4.98E-07	1.26E-08	3.56E-13	1.35E-14	1.81E-20	1.09E-19	0.0095
28-358-2A/B	DC3 Reflux Pumps	2	1	-	-	11.24	6	-	-	-	30.27	6.01E-10	0.05	0.92	0.03	3.14E-03	1.13E-07	1.13E-07	1.60E-08	9.69E-08	0.0133
28-358-3A/B	C3 Inject pumps	2	1	-	-	11.24	6	-	-	-	30.27	6.01E-10	0.05	0.92	0.03	3.14E-03	1.13E-07	1.13E-07	1.60E-08	9.69E-08	0.0133
28-358-4A/B	DC4 Reflux pumps	2	1	-	-	11.24	6	-	-	-	35.24	6.71E-27	8.47E-11	2.62E-03	0.29	0.70	3.78E-03	1.64E-04	3.81E-11	2.30E-10	0.0175
28-358-5A/B	Gasoline booster pumps	2	1	-	-	11.24	6	-	-	-	39.49	2.08E-31	5.24E-26	5.88E-12	4.59E-05	5.64E-03	0.31	0.27	0.06	0.36	0.0225
28-358-6A/B	Gasoline injection pumps	2	1	-	-	11.24	6	-	-	-	39.49	2.08E-31	5.24E-26	5.88E-12	4.59E-05	5.64E-03	0.31	0.27	0.06	0.36	0.0225
28-358-7A/B	C4 split bottoms pumps	2	1	-	-	11.24	6	-	-	-	34.22	2.43E-26	3.06E-10	9.46E-03	0.97	0.02	8.82E-17	1.29E-21	1.76E-31	1.06E-30	0.0174
28-358-8A/B	C4 split reflux pumps	2	1	-	-	11.24	6	-	-	-	35.62	2.76E-31	5.17E-31	1.27E-19	0.03	0.97	5.23E-03	2.27E-04	5.26E-11	3.18E-10	0.0176
28-358-9A/B	C4 Split comp K.O. drum pumps	2	1	-	-	11.24	6	-	-	-	34.22	2.43E-26	3.06E-10	9.46E-03	0.97	0.02	8.82E-17	1.29E-21	1.76E-31	1.06E-30	0.0174
28-358-10A/B	iC4 injection pumps	2	1	-	-	11.24	6	-	-	-	34.22	2.43E-26	3.06E-10	9.46E-03	0.97	0.02	8.82E-17	1.29E-21	1.76E-31	1.06E-30	0.0174
28-358-11A/B	nC4 injection pumps	2	1	-	-	11.24	6	-	-	-	35.62	2.76E-31	5.17E-31	1.27E-19	0.03	0.97	5.23E-03	2.27E-04	5.26E-11	3.18E-10	0.0176

[1] Total Volume (ft^3/event) = Pi x (ID (ft) / 2)^2 x Height (ft)

Pressure Vessel 31-358-1 Deeth C3 Total Volume (ft^3/event) = π | (16 ft / 2)^2 | 126 ft = 28,551 ft3/event

[2] Total Volume Rate or Heel Volume Rate (ft^3/hr) = Total Volume or Heel Volume (ft^3/event) / Hours Per Event (hr/event)

Pressure Vessel 31-358-1 Deeth C3 Total Volume Rate (ft^3/hr) = (28,551 ft3 / event) | (event / 12 hr) = 2,379 ft3/hr

[3] Heel Volume (ft^3/event) = Pi x (ID (ft)/2)^2 x Heel (ft)

Pressure Vessel 31-358-1 Deeth C3 Heel Volume (ft^3/event) = π | (16 ft / 2)^2 | 2 ft = 3,927 ft3/event

[4] The mass fraction ratio of n-hexane to n-hexane and higher is 14.2 %

Targa Midstream Services LLC - Mont Belvieu Plant
Shutdown Emissions Sent to FLR-5

Shutdown Liquid Emissions Sent to FLR-5

			Weight Per Hour (lb/hr) [1]									Weight Per Year (lb/yr) [2]								
Unit ID	Description	Emission Groups	C1	C2	C3	iC4	C4	iC5	C5	C6	C7	C1	C2	C3	iC4	C4	iC5	C5	C6	C7
Pressure Vessels																				
31-358-1 Deeth	DC2	F	0.06	4.62	1.92	1.47	1.37	0.68	0.51	0.14	0.87	0.70	55.49	23.01	17.59	16.42	8.18	6.16	1.74	10.50
30-358-1	DC2 Reflux Accum	F	6.96E-03	0.54	7.92E-03	5.55E-07	1.40E-08	3.97E-13	1.51E-14	2.02E-20	1.22E-19	0.08	6.51	0.10	6.66E-06	1.69E-07	4.77E-12	1.81E-13	2.42E-19	1.46E-18
30-358-4	C2 Comp suct scrub	F	2.94E-03	0.23	3.35E-03	2.34E-07	5.93E-09	1.68E-13	6.38E-15	8.52E-21	5.15E-20	0.04	2.75	0.04	2.81E-06	7.12E-08	2.01E-12	7.65E-14	1.02E-19	6.18E-19
30-358-6	Refrig comp suct scrub	F	3.81E-10	0.03	0.59	0.03	3.98E-03	1.43E-07	1.43E-07	2.03E-08	1.23E-07	4.58E-09	0.36	7.03	0.39	0.05	1.72E-06	1.72E-06	2.44E-07	1.47E-06
30-358-7	Refrig Accumulator	F	3.81E-10	0.03	0.59	0.03	3.98E-03	1.43E-07	1.43E-07	2.03E-08	1.23E-07	4.58E-09	0.36	7.03	0.39	0.05	1.72E-06	1.72E-06	2.44E-07	1.47E-06
31-358-4	DC3	F	1.84E-09	0.14	2.84	1.65	3.67	1.21	1.06	0.23	1.39	2.21E-08	1.73	34.07	19.83	44.00	14.57	12.70	2.77	16.73
30-358-9	DC3 Reflux Accum	F	5.96E-10	0.05	0.92	0.05	6.22E-03	2.24E-07	2.24E-07	3.18E-08	1.92E-07	7.15E-09	0.56	10.99	0.61	0.07	2.69E-06	2.69E-06	3.81E-07	2.30E-06
30-358-401A/B	C3 COS Reactors	F	4.29E-10	0.03	0.66	0.04	4.48E-03	1.61E-07	1.61E-07	2.29E-08	1.38E-07	2.57E-09	0.20	3.95	0.22	0.03	9.67E-07	9.67E-07	1.37E-07	8.30E-07
30-358-402A/B	C3 H2S Reactors	F	5.84E-10	0.05	0.90	0.05	6.10E-03	2.19E-07	2.19E-07	3.11E-08	1.88E-07	3.50E-09	0.27	5.38	0.30	0.04	1.32E-06	1.32E-06	1.87E-07	1.13E-06
31-358-5	DC4	G	1.67E-26	2.11E-10	6.52E-03	1.45	3.53	1.17	1.02	0.22	1.35	2.01E-25	2.53E-09	0.08	17.35	42.31	14.09	12.28	2.68	16.18
30-358-10	DC4 Reflux accum	G	5.59E-27	7.06E-11	2.18E-03	0.48	1.17	6.30E-03	2.73E-04	6.34E-11	3.83E-10	6.71E-26	8.47E-10	0.03	5.80	14.06	0.08	3.28E-03	7.61E-10	4.60E-09
31-358-6	C4 Splitter	G	4.46E-26	5.63E-10	0.02	3.85	9.34	0.05	2.18E-03	5.06E-10	3.06E-09	5.35E-25	6.75E-09	0.21	46.25	112.12	0.60	0.03	6.07E-09	3.67E-08
30-358-11	C4 Splitter comp K.O.	G	1.15E-26	1.45E-10	4.47E-03	0.92	0.02	8.34E-17	1.22E-21	1.66E-31	1.00E-30	1.38E-25	1.74E-09	0.05	11.05	0.20	1.00E-15	1.47E-20	1.99E-30	1.20E-29
30-358-12	C4 Splitter Reflux accum.	G	1.96E-26	2.48E-10	7.65E-03	1.57	0.03	1.43E-16	2.09E-21	2.84E-31	1.72E-30	2.35E-25	2.97E-09	0.09	18.89	0.34	1.71E-15	2.51E-20	3.41E-30	2.06E-29
30-358-501A/B/C	Gasoline treaters	G	1.72E-31	4.33E-26	4.86E-12	7.59E-05	9.34E-03	0.51	0.45	0.10	0.59	2.06E-30	5.20E-25	5.83E-11	9.11E-04	0.11	6.08	5.38	1.17	7.10
30-358-502A/B/C	Caustic separators	G	9.66E-32	2.44E-26	2.73E-12	4.27E-05	5.25E-03	0.29	0.25	0.06	0.33	1.16E-30	2.92E-25	3.28E-11	5.12E-04	0.06	3.42	3.03	0.66	3.99
30-358-601A/B	Caustic Contactors	G	3.86E-31	9.75E-26	1.09E-11	1.71E-04	0.02	1.14	1.01	0.22	1.33	4.64E-30	1.17E-24	1.31E-10	2.05E-03	0.25	13.69	12.11	2.64	15.97
30-358-602A/B	Caustic Settlers	G	9.66E-32	2.44E-26	2.73E-12	4.27E-05	5.25E-03	0.29	0.25	0.06	0.33	1.16E-30	2.92E-25	3.28E-11	5.12E-04	0.06	3.42	3.03	0.66	3.99
Pipelines																				
	RP	-	0.02	1.43	0.59	0.45	0.42	0.21	0.16	0.04	0.27	0.22	17.16	7.11	5.44	5.08	2.53	1.91	0.54	3.25
	C2	-	0.02	1.72	0.03	1.76E-06	4.45E-08	1.26E-12	4.78E-14	6.39E-20	3.86E-19	0.26	20.61	0.30	2.11E-05	5.34E-07	1.51E-11	5.74E-13	7.66E-19	4.63E-18
	C3	-	1.51E-09	0.12	2.32	0.13	0.02	5.67E-07	5.67E-07	8.05E-08	4.87E-07	1.81E-08	1.42	27.83	1.54	0.19	6.80E-06	6.80E-06	9.66E-07	5.84E-06
	iC4	-	5.16E-26	6.51E-10	0.02	4.14	0.08	3.75E-16	5.50E-21	7.47E-31	4.51E-30	6.19E-25	7.81E-09	0.24	49.68	0.90	4.50E-15	6.60E-20	8.96E-30	5.42E-29
	nC4	-	6.10E-31	1.14E-30	2.82E-19	0.13	4.28	0.02	1.00E-03	2.33E-10	1.41E-09	7.32E-30	1.37E-29	3.38E-18	1.54	51.33	0.28	0.01	2.80E-09	1.69E-08
	C5+	-	5.10E-31	1.29E-25	1.44E-11	2.25E-04	0.03	1.50	1.33	0.29	1.76	6.12E-30	1.54E-24	1.73E-10	2.70E-03	0.33	18.06	15.98	3.49	21.07
Filters/Coalescers																				
15-358-1A/B	Plant inlet feed filters	-	3.08E-03	0.24	0.10	0.08	0.07	0.04	0.03	7.63E-03	0.05	6.16E-03	0.49	0.20	0.15	0.14	0.07	0.05	0.02	0.09
15-358-2A/B	Plant feed inlet coalescers	-	8.55E-03	0.68	0.28	0.21	0.20	0.10	0.08	0.02	0.13	0.02	1.35	0.56	0.43	0.40	0.20	0.15	0.04	0.26
15-358-401	Treated Propane Filter Coalescer	-	3.22E-10	0.03	0.49	0.03	3.36E-03	1.21E-07	1.21E-07	1.72E-08	1.04E-07	6.43E-10	0.05	0.99	0.05	6.72E-03	2.42E-07	2.42E-07	3.43E-08	2.07E-07
15-358-501	Treated gasoline coalescer	-	8.76E-32	2.21E-26	2.48E-12	3.87E-05	4.76E-03	0.26	0.23	0.05	0.30	1.75E-31	4.42E-26	4.96E-12	7.75E-05	9.53E-03	0.52	0.46	0.10	0.60
15-358-601	n-butane product coalescer	-	1.73E-31	3.25E-31	8.00E-20	0.04	1.22	6.58E-03	2.86E-04	6.63E-11	4.00E-10	3.47E-31	6.51E-31	1.60E-19	0.07	2.43	0.01	5.71E-04	1.33E-10	8.01E-10
Pumps																				
28-358-1A/B	DC2 Reflux Pumps	-	0.01	0.93	0.01	9.53E-07	2.41E-08	6.82E-13	2.59E-14	3.46E-20	2.09E-19	0.02	1.86	0.03	1.91E-06	4.82E-08	1.36E-12	5.18E-14	6.92E-20	4.18E-19
28-358-2A/B	DC3 Reflux Pumps	-	1.02E-09	0.08	1.57	0.09	0.01	3.84E-07	3.84E-07	5.46E-08	3.30E-07	2.05E-09	0.16	3.14	0.17	0.02	7.68E-07	7.68E-07	1.09E-07	6.59E-07
28-358-3A/B	C3 Inject pumps	-	1.02E-09	0.08	1.57	0.09	0.01	3.84E-07	3.84E-07	5.46E-08	3.30E-07	2.05E-09	0.16	3.14	0.17	0.02	7.68E-07	7.68E-07	1.09E-07	6.59E-07
28-358-4A/B	DC4 Reflux pumps	-	1.33E-26	1.68E-10	5.18E-03	1.15	2.78	0.01	6.50E-04	1.51E-10	9.11E-10	2.66E-26	3.35E-10	0.01	2.30	5.57	0.03	1.30E-03	3.01E-10	1.82E-09
28-358-5A/B	Gasoline booster pumps	-	4.61E-31	1.16E-25	1.30E-11	2.04E-04	0.03	1.36	1.20	0.26	1.59	9.21E-31	2.32E-25	2.61E-11	4.07E-04	0.05	2.72	2.41	0.53	3.17
28-358-6A/B	Gasoline injection pumps	-	4.61E-31	1.16E-25	1.30E-11	2.04E-04	0.03	1.36	1.20	0.26	1.59	9.21E-31	2.32E-25	2.61E-11	4.07E-04	0.05	2.72	2.41	0.53	3.17
28-358-7A/B	C4 split bottoms pumps	-	4.66E-26	5.88E-10	0.02	3.74	0.07	3.39E-16	4.97E-21	6.75E-31	4.08E-30	9.33E-26	1.18E-09	0.04	7.48	0.14	6.78E-16	9.93E-21	1.35E-30	8.16E-30
28-358-8A/B	C4 split reflux pumps	-	5.52E-31	1.03E-30	2.54E-19	0.12	3.86	0.02	9.08E-04	2.11E-10	1.27E-09	1.10E-30	2.07E-30	5.09E-19	0.23	7.73	0.04	1.82E-03	4.21E-10	2.55E-09
28-358-9A/B	C4 Split comp K.O. drum pumps	-	4.66E-26	5.88E-10	0.02	3.74	0.07	3.39E-16	4.97E-21	6.75E-31	4.08E-30	9.33E-26	1.18E-09	0.04	7.48	0.14	6.78E-16	9.93E-21	1.35E-30	8.16E-30
28-358-10A/B	iC4 injection pumps	-	4.66E-26	5.88E-10	0.02	3.74	0.07	3.39E-16	4.97E-21	6.75E-31	4.08E-30	9.33E-26	1.18E-09	0.04	7.48	0.14	6.78E-16	9.93E-21	1.35E-30	8.16E-30
28-358-11A/B	nC4 injection pumps	-	5.52E-31	1.03E-30	2.54E-19	0.12	3.86	0.02	9.08E-04	2.11E-10	1.27E-09	1.10E-30	2.07E-30	5.09E-19	0.23	7.73	0.04	1.82E-03	4.21E-10	2.55E-09
Emissions [3]			0.07	5.73	8.41	8.28	14.13	3.45	2.99	0.65	3.94	1.35	111.51	135.73	223.14	312.59	91.36	78.10	17.56	106.08

[1] Controlled Weight Per Hour (lb/hr) = Total or Heel Volume Rate (ft^3/hr) x Liquid Density (lb/ft^3) x Component Vapor Mass Fraction x (100-(Flare Destruction Factor (%))/100

Pressure Vessel 31-358-1 Deeth C3 Weight Per Hour (lb/hr) = $\frac{34\ ft3}{hr} \times \frac{27.23\ lb}{ft^3} \times 0.21 \times \frac{100-99\%}{100}$ = 1.92 lb/hr

[2] Controlled Weight Per Year (lb/yr) = Total Volume (ft^3) x Liquid Density (lb/ft^3) x Component Vapor Mass Fraction x Frequency/Year x (100-(Flare Destruction Factor (%))/100

Pressure Vessel 31-358-1 Deeth C3 Weight Per Year (lb/yr) = $28{,}551\ ft3 \times \frac{27.23\ lb}{ft^3} \times 0.21 \times \frac{1\ event}{yr} \times \frac{100-99\%}{100}$ = 23.01 lb/yr

[3] Each of the pipelines, filters/coalescers, pumps, and pressure vessels groups occur at separate instances. Therefore, hourly emissions are based on the maximum emissions for the sum of the emissions of Group F, G, and each of the remaining units. The annual emissions (lb/yr) are the sum of the speciated emissions of all units.

Shutdown Vapor Parameters Sent to FLR-5

Unit ID	Description	Hours Per Event (hr/event)	Frequency per Year (event/yr)	ID (ft)	Height (ft)	Total Volume [1] (ft^3/event)	Total Volume Rate [2] (ft^3/hr)	Vapor Density (lb/ft^3)	Component Vapor Mass Fraction [3] C1	C2	C3	iC4	C4	iC5	C5	C6	C7	Gas Heating Rate [4] (MMBtu/hr)
Pressure Vessels																		
31-358-1 Deeth	DC2	12	1	16	126	28,551	2,379	3.35	0.03	0.78	0.13	0.03	0.02	5.26E-03	3.26E-03	4.16E-04	2.51E-03	4.42
30-358-1	DC2 Reflux Accum	12	1	10	50	4,712	393	7.72	0.02	0.97	9.82E-03	2.64E-07	6.07E-09	6.07E-09	6.07E-09	8.61E-10	5.20E-09	0.66
30-358-4	C2 Comp suct scrub	12	1	6.5	10	548	46	7.72	0.02	0.97	9.82E-03	2.64E-07	6.07E-09	6.07E-09	6.07E-09	8.61E-10	5.20E-09	0.08
30-358-6	Refrig comp suct scrub	12	1	8	10	905	75	1.50	7.13E-09	0.13	0.86	0.01	1.00E-03	1.65E-08	1.65E-08	2.35E-09	1.42E-08	0.17
30-358-7	Refrig Accumulator	12	1	8	24	1,608	134	1.50	7.13E-09	0.13	0.86	0.01	1.00E-03	1.65E-08	1.65E-08	2.35E-09	1.42E-08	0.31
31-358-4	DC3	12	1	13	114	16,857	1,405	0.83	6.82E-09	0.11	0.65	0.08	0.13	0.02	0.01	9.13E-04	5.52E-03	3.54
30-358-9	DC3 Reflux Accum	12	1	10	40	3,927	327	1.50	7.13E-09	0.13	0.86	0.01	1.00E-03	1.65E-08	1.65E-08	2.35E-09	1.42E-08	0.75
30-358-401A/B	C3 COS Reactors	6	1	6	30	1,018	170	1.50	7.13E-09	0.13	0.86	0.01	1.00E-03	1.65E-08	1.65E-08	2.35E-09	1.42E-08	0.39
30-358-402A/B	C3 H2S Reactors	6	1	7	34	1,578	263	1.50	7.13E-09	0.13	0.86	0.01	1.00E-03	1.65E-08	1.65E-08	2.35E-09	1.42E-08	0.61
31-358-5	DC4	12	1	9.5	98	7,620	635	0.33	3.36E-25	7.86E-10	6.91E-03	0.31	0.54	0.07	0.05	3.35E-03	0.02	2.04
30-358-10	DC4 Reflux accum	12	1	8.5	30	2,185	182	0.46	3.64E-25	3.64E-25	7.91E-03	0.36	0.63	1.40E-03	4.62E-05	3.52E-12	2.13E-11	0.57
31-358-6	C4 Splitter	12	1	12	212	25,334	2,111	0.46	3.64E-25	3.64E-25	7.91E-03	0.36	0.63	1.40E-03	4.62E-05	3.52E-12	2.13E-11	6.57
30-358-11	C4 Splitter comp K.O.	12	1	6.5	16	747	62	0.59	3.64E-25	3.64E-25	0.02	0.96	0.01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.19
30-358-12	C4 Splitter Reflux accum	12	1	8.5	40	2,752	229	0.46	3.64E-25	3.64E-25	0.02	0.96	0.01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.71
30-358-501A/B/C	Gasoline treaters	12	1	8	16	3,619	302	0.12	0.00E+00	2.77E-24	8.57E-11	2.64E-04	0.02	0.49	0.33	0.02	0.13	1.15
30-358-502A/B/C	Caustic separators	12	1	6	20	2,205	184	0.12	0.00E+00	2.77E-24	8.57E-11	2.64E-04	0.02	0.49	0.33	0.02	0.13	0.70
30-358-601A/B	Caustic Contactors	12	1	12	50	14,024	1,169	0.12	0.00E+00	2.77E-24	8.57E-11	2.64E-04	0.02	0.49	0.33	0.02	0.13	4.45
30-358-602A/B	Caustic Settlers	12	1	6	30	2,036	170	0.12	0.00E+00	2.77E-24	8.57E-11	2.64E-04	0.02	0.49	0.33	0.02	0.13	0.65
Pipelines																		
	RP	12	1	0.83	3,800	2,487	207	3.35	0.03	0.78	0.13	0.03	0.02	5.26E-03	3.26E-03	4.16E-04	2.51E-03	0.38
	C2	12	1	0.83	3,800	2,487	207	7.72	0.02	0.97	9.82E-03	2.64E-07	6.07E-09	6.07E-09	6.07E-09	8.61E-10	5.20E-09	0.35
	C3	12	1	0.67	3,800	1,990	166	1.50	7.13E-09	0.13	0.86	0.01	1.00E-03	1.65E-08	1.65E-08	2.35E-09	1.42E-08	0.38
	iC4	12	1	0.5	3,800	1,492	124	0.59	3.64E-25	3.64E-25	0.02	0.96	0.01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.38
	nC4	12	1	0.5	3,800	1,492	124	0.40	0.00E+00	0.00E+00	0.00E+00	0.04	0.96	2.10E-03	1.00E-04	0.00E+00	0.00E+00	0.39
	C5+	12	1	0.5	3,800	1,492	124	0.12	0.00E+00	2.77E-24	8.57E-11	2.64E-04	0.02	0.49	0.33	0.02	0.13	0.47
Filters/Coalescers																		
15-358-1A/B	Plant inlet feed filters	2	1	3	7.25	51	26	3.35	0.03	0.78	0.13	0.03	0.02	5.26E-03	3.26E-03	4.16E-04	2.51E-03	0.05
15-358-2A/B	Plant feed inlet coalescers	2	1	5	5.25	103	52	3.35	0.03	0.78	0.13	0.03	0.02	5.26E-03	3.26E-03	4.16E-04	2.51E-03	0.10
15-358-401	Treated Propane Filter Coalescer	2	1	3	5.25	37	19	1.50	7.13E-09	0.13	0.86	0.01	1.00E-03	1.65E-08	1.65E-08	2.35E-09	1.42E-08	0.04
15-358-501	Treated gasoline coalescer	2	1	2.33	5.25	22	11	0.12	0.00E+00	2.77E-24	8.57E-11	2.64E-04	0.02	0.49	0.33	0.02	0.13	0.04
15-358-601	n-butane product coalescer	2	1	3	5.25	37	19	0.40	0.00E+00	0.00E+00	0.00E+00	0.04	0.96	2.10E-03	1.00E-04	0.00E+00	0.00E+00	0.06
Compressors																		
11-358-1A/B	Ethane	1	1	-	-	2,000	2,000	7.72	0.02	0.97	9.82E-03	2.64E-07	6.07E-09	6.07E-09	6.07E-09	8.61E-10	5.20E-09	3.38
11-358-2A/B	Refrigeration	2	1	-	-	1,200	600	1.50	7.13E-09	0.13	0.86	0.01	1.00E-03	1.65E-08	1.65E-08	2.35E-09	1.42E-08	1.38
11-358-3	C4 Splitter	2	1	-	-	1,000	500	0.59	3.64E-25	3.64E-25	0.02	0.96	0.01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.54

[1] Total Volume (ft^3/event) = Pi x (ID (ft) / 2)^2 x Height (ft)

Pressure Vessel 31-358-1 Deeth Total Volume (ft^3/event) = π | (16 ft / 2)^2 | 126 ft = 28,551 ft3/event

[2] Total Volume Rate (ft^3/hr) = Total Volume (ft^3/event) / Hours Per Event (hr/event)

Pressure Vessel 31-358-1 Deeth Total Volume (ft^3/hr) = 28,551 ft3 / event | event / 12 hr = 2,379 ft3/hr

[3] The mass fraction ratio of n-hexane to n-hexane and higher is 14.2 %

[4] Speciated Gas Heating Rate (MMBtu/hr) = Gas Volume Flow Rate (ft^3/hr) x Component Mass Fraction x Higher Heating Value (Btu/ft^3) x 1 MMBtu / 1,000,000 Btu

Shutdown Vapor Emissions Sent to FLR-5

			Controlled Weight Per Hour (lb/hr) [1]									Controlled Weight Per Year (lb/yr) [2]								
Unit ID	**Description**	**Emission Groups**	**C1**	**C2**	**C3**	**iC4**	**C4**	**iC5**	**C5**	**C6**	**C7**	**C1**	**C2**	**C3**	**iC4**	**C4**	**iC5**	**C5**	**C6**	**C7**
Pressure Vessels																				
31-358-1 Deeth	DC2	H	2.57	61.80	10.58	4.29	3.16	0.84	0.52	0.07	0.40	30.83	741.64	126.92	51.47	37.92	10.05	6.23	0.79	4.80
30-358-1	DC2 Reflux Accum	H	0.62	29.40	0.30	1.60E-05	3.68E-07	3.68E-07	3.68E-07	5.22E-08	3.16E-07	7.39	352.79	3.57	1.92E-04	4.41E-06	4.41E-06	4.41E-06	6.27E-07	3.79E-06
30-358-4	C2 Comp suct scrub	H	0.07	3.42	0.03	1.86E-06	4.27E-08	4.27E-08	4.27E-08	6.07E-09	3.67E-08	0.86	40.99	0.41	2.23E-05	5.13E-07	5.13E-07	5.13E-07	7.28E-08	4.40E-07
30-358-6	Refrig comp suct scrub	I	8.04E-09	0.15	0.97	0.02	2.26E-03	3.73E-08	3.73E-08	5.29E-09	3.20E-08	9.65E-08	1.75	11.61	0.29	0.03	4.47E-07	4.47E-07	6.35E-08	3.84E-07
30-358-7	Refrig Accumulator	I	1.43E-08	0.26	1.72	0.04	4.01E-03	6.63E-08	6.63E-08	9.41E-09	5.68E-08	1.72E-07	3.12	20.64	0.52	0.05	7.95E-07	7.95E-07	1.13E-07	6.82E-07
31-358-4	DC3	J	7.97E-08	1.26	7.55	1.87	3.02	0.43	0.29	0.02	0.13	9.57E-07	15.13	90.65	22.44	36.20	5.12	3.43	0.26	1.55
30-358-9	DC3 Reflux Accum	J	3.49E-08	0.63	4.20	0.11	9.80E-03	1.62E-07	1.62E-07	2.30E-08	1.39E-07	4.19E-07	7.61	50.40	1.28	0.12	1.94E-06	1.94E-06	2.76E-07	1.67E-06
30-358-401A/B	C3 COS Reactors	K	1.81E-08	0.33	2.18	0.06	5.08E-03	8.39E-08	8.39E-08	1.19E-08	7.19E-08	1.09E-07	1.97	13.06	0.33	0.03	5.03E-07	5.03E-07	7.14E-08	4.32E-07
30-358-402A/B	C3 H2S Reactors	K	2.80E-08	0.51	3.37	0.09	7.87E-03	1.30E-07	1.30E-07	1.85E-08	1.12E-07	1.68E-07	3.06	20.25	0.51	0.05	7.80E-07	7.80E-07	1.11E-07	6.69E-07
31-358-5	DC4	L	6.94E-25	1.62E-09	0.01	1.28	2.23	0.30	0.20	0.01	0.08	8.33E-24	1.95E-08	0.17	15.34	26.70	3.61	2.38	0.17	1.00
30-358-10	DC4 Reflux accum	L	3.02E-25	3.02E-25	6.56E-03	0.60	1.04	2.32E-03	7.66E-05	5.84E-12	3.53E-11	3.62E-24	3.62E-24	0.08	7.19	12.53	0.03	9.19E-04	7.00E-11	4.23E-10
31-358-6	C4 Splitter	L	3.50E-24	3.50E-24	0.08	6.95	12.11	0.03	8.88E-04	6.77E-11	4.09E-10	4.20E-23	4.20E-23	0.91	83.38	145.30	0.32	0.01	8.12E-10	4.91E-09
30-358-11	C4 Splitter comp K.O.	L	1.35E-25	1.35E-25	8.31E-03	0.71	9.46E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.61E-24	1.61E-24	0.10	8.55	0.11	0.00E+00	0.00E+00	0.00E+00	0.00E+00
30-358-12	C4 Splitter Reflux accum	L	3.81E-25	3.81E-25	0.02	2.02	0.03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.57E-24	4.57E-24	0.28	24.19	0.32	0.00E+00	0.00E+00	0.00E+00	0.00E+00
30-358-501A/B/C	Gasoline treaters	L	0.00E+00	9.91E-25	3.07E-11	1.89E-04	0.02	0.35	0.23	0.02	0.10	0.00E+00	1.19E-23	3.68E-10	2.27E-03	0.20	4.24	2.81	0.19	1.15
30-358-502A/B/C	Caustic separators	L	0.00E+00	6.04E-25	1.87E-11	1.15E-04	0.01	0.22	0.14	9.66E-03	0.06	0.00E+00	7.24E-24	2.24E-10	1.38E-03	0.12	2.58	1.71	0.12	0.70
30-358-601A/B	Caustic Contactors	L	0.00E+00	3.84E-24	1.19E-10	7.32E-04	0.06	1.37	0.91	0.06	0.37	0.00E+00	4.61E-23	1.43E-09	8.79E-03	0.76	16.43	10.89	0.74	4.45
30-358-602A/B	Caustic Settlers	L	0.00E+00	5.57E-25	1.73E-11	1.06E-04	9.24E-03	0.20	0.13	8.92E-03	0.05	0.00E+00	6.69E-24	2.07E-10	1.28E-03	0.11	2.39	1.58	0.11	0.65
Pipelines																				
	RP	-	0.22	5.38	0.92	0.37	0.28	0.07	0.05	5.77E-03	0.03	2.69	64.60	11.06	4.48	3.30	0.88	0.54	0.07	0.42
	C2	-	0.33	15.52	0.16	8.43E-06	1.94E-07	1.94E-07	1.94E-07	2.76E-08	1.67E-07	3.90	186.19	1.88	1.01E-04	2.33E-06	2.33E-06	2.33E-06	3.31E-07	2.00E-06
	C3	-	1.77E-08	0.32	2.13	0.05	4.96E-03	8.20E-08	8.20E-08	1.16E-08	7.03E-08	2.12E-07	3.86	25.53	0.65	0.06	9.83E-07	9.83E-07	1.40E-07	8.44E-07
	iC4	-	2.69E-25	2.69E-25	0.02	1.42	0.02	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.23E-24	3.23E-24	0.20	17.10	0.23	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	nC4	-	0.00E+00	0.00E+00	0.00E+00	0.04	0.96	2.11E-03	1.00E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.48	11.55	0.03	1.21E-03	0.00E+00	0.00E+00
	C5+	-	0.00E+00	4.08E-25	1.27E-11	7.79E-05	6.78E-03	0.15	0.10	6.54E-03	0.04	0.00E+00	4.90E-24	1.52E-10	9.35E-04	0.08	1.75	1.16	0.08	0.47
Filters/Coalescers																				
15-358-1A/B	Plant inlet feed filters	-	0.03	0.67	0.11	0.05	0.03	9.02E-03	5.59E-03	7.13E-04	4.31E-03	0.06	1.33	0.23	0.09	0.07	0.02	0.01	1.43E-03	8.62E-03
15-358-2A/B	Plant feed inlet coalescers	-	0.06	1.34	0.23	0.09	0.07	0.02	0.01	1.43E-03	8.67E-03	0.11	2.68	0.46	0.19	0.14	0.04	0.02	2.87E-03	0.02
15-358-401	Treated Propane Filter Coalescer	-	1.98E-09	0.04	0.24	6.04E-03	5.56E-04	9.17E-09	9.17E-09	1.30E-09	7.87E-09	3.96E-09	0.07	0.48	0.01	1.11E-03	1.83E-08	1.83E-08	2.60E-09	1.57E-08
15-358-501	Treated gasoline coalescer	-	0.00E+00	3.69E-26	1.14E-12	7.03E-06	6.12E-04	0.01	8.72E-03	5.90E-04	3.56E-03	0.00E+00	7.37E-26	2.28E-12	1.41E-05	1.22E-03	0.03	0.02	1.18E-03	7.13E-03
15-358-601	n-butane product coalescer	-	0.00E+00	0.00E+00	0.00E+00	6.01E-03	0.14	3.15E-04	1.50E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.01	0.29	6.30E-04	3.00E-05	0.00E+00	0.00E+00
Compressors																				
11-358-1A/B	Ethane	-	3.14	149.73	1.52	8.14E-05	1.87E-06	1.87E-06	1.87E-06	2.66E-07	1.61E-06	3.14	149.73	1.52	8.14E-05	1.87E-06	1.87E-06	1.87E-06	2.66E-07	1.61E-06
11-358-2A/B	Refrigeration	-	6.40E-08	1.16	7.70	0.20	0.02	2.97E-07	2.97E-07	4.21E-08	2.54E-07	1.28E-07	2.33	15.40	0.39	0.04	5.93E-07	5.93E-07	8.42E-08	5.09E-07
11-358-3	C4 Splitter	-	1.08E-24	1.08E-24	0.07	5.73	0.08	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.16E-24	2.16E-24	0.13	11.46	0.15	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Emissions [3]			3.26	149.73	11.75	11.56	15.51	2.47	1.62	0.11	0.66	48.98	1,578.85	395.94	250.40	276.46	47.50	30.81	2.52	15.23

[1] Controlled Weight Per Hour (lb/hr) = Total Volume Rate (ft^3/hr) x Liquid Density (lb/ft^3) x Component Vapor Mass Fraction x (100-(Flare Destruction Factor (%))/100

Pressure Vessel 31-358-1 Deeth C3 Weight Per Hour (lb/hr) =	2,379 ft3 / hr	3.35 lb / ft^3	0.13	100-99% / 100	=	10.58 lb/hr

[2] Controlled Weight Per Year (lb/yr) = Total Volume (ft^3/event) x Liquid Density (lb/ft^3) x Component Vapor Mass Fraction x Frequency/Year x (100-(Flare Destruction Factor (%))/100

Pressure Vessel 31-358-1 Deeth C3 Weight Per Year (lb/yr) =	28,551 ft3 / event	3.35 lb / ft^3	0.13	1 event / yr	100-99% / 100	=	126.92 lb/yr

[3] Each of the pipelines, filters/coalescers, compressors, and pressure vessels groups occur at separate instances. Therefore, hourly emissions are based on the maximum emissions for the sum of the emissions of Group H, I J, K, L, and each of the remaining units. The annual emissions (lb/yr) are the sum of the speciated emissions of all units.

Targa Midstream Services LLC - Mont Belvieu Plant
Shutdown Emissions Sent to FLR-5

GHG Emissions

Input Data		
Maximum Hourly Release to Flare [1] =	5,043.45	scf/hr
Annual Releases to Flare [1] =	138,356.04	scf/yr
Higher Heating Value for N_2O [2] =	1.235E-03	MMBtu/scf

[1] Hourly inlet to flare based on the release among the sum of the releases for Group F, G, H, I, J, K, L, and each of the remaining units. Annual inlet to flare based on the sum of the releases from all vapor events and all liquids events.
[2] Per 40 CFR Part 98, Subpart W, Equation W-40

Global Warming Potentials [1]

CO_2	CH_4	N_2O
1	21	310

[1] Global warming potentials (GWP) obtained from 40 CFR 98 Subpart A Table A-1.

N_2O Emissions

Emission Factor[1,2]		N_2O Emissions[3,4]	
(kg/MMBtu)	(lb/MMBtu)	(lb/hr)	(tpy)
1.00E-04	2.20E-04	1.37E-03	1.88E-05

[1] Per 40 CFR 98 Subpart W, Equation W-40.
[2] Emission factors converted from kg/MMBtu to lb/MMBtu using the following conversion: GHG Emission Factor (lb/MMBtu) = GHG Emission Factor (kg/MMBtu) x 2.2046 (lb/kg)
[3] Hourly Emission Rate for N_2O (lb/hr) = Gas Flowrate (scf/hr) x Subpart W Process Gas HHV (MMBtu/scf) x Emission Factor (lb/MMBtu)

Example N_2O Hourly Emissions (lb/hr) = 5,043.45 scf / hr | 1.235E-03 MMBtu / scf | 2.20E-04 lb / MMBtu = 1.37E-03 lb/hr

[4] Annual Emission Rate for N_2O (tpy) = Gas Flowrate (scf/yr) x Subpart W Process Gas HHV (MMBtu/scf) x Emission Factor (lb/MMBtu) / 2,000 (lb/ton)

Example N_2O Annual Emission Rate (tpy) = 138,356.04 scf / yr | 1.235E-03 MMBtu / scf | 2.20E-04 lb / MMBtu | 1 ton / 2,000 lb = 1.88E-05 tpy

Speciated GHG Emissions - FLR-5

Gas Stream	Compound	Number of Carbon Atoms	DRE [1] (%)	Inlet to Flare [2] (lb/hr)	Inlet to Flare (tpy)	Controlled GHG Emissions[3,4] (lb/hr)	Controlled GHG Emissions (tpy)	Converted to CO_2 [5,6] (lb/hr)	Converted to CO_2 (tpy)
Emissions to FLR-5	Methane	1	99%	325.72	2.52	3.26	0.03	322.46	2.49
	Ethane	2	99%	14,972.69	84.52	--	--	29,645.93	167.35
	Propane	3	99%	1,175.37	26.58	--	--	3,490.85	78.95
	Butanes	4	98%	1,353.48	26.56	--	--	5,305.63	104.13
	Pentanes +	5	98%	551.18	9.73	--	--	2,700.80	47.67

FLR-5 GHG Emissions [7]	(lb/hr)	(tpy)
CO_2	41,465.66	400.59
CH_4	3.26	0.03
N_2O	1.37E-03	1.88E-05
CO_2e	41,534.48	401.13

[1] TCEQ Air Permits Division, Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers, RG-109 (Draft), October 2000.
[2] Hourly inlet to flare based on the release among the sum of the releases for Group F, G, H, I, J, K, L, and each of the remaining units. Annual inlet to flare based on the sum of the releases from all vapor events and all liquids events.
[3] Controlled GHG Emission (lb/hr) = Inlet to Flare (lb/hr) x (100 - Flare DRE (%))/100

Example Controlled Methane Hourly Emission Rate (lb/hr) = 325.72 lb / hr | (100 - 99%) / 100 = 3.26 lb/hr

[4] Controlled GHG Emission (tpy) = Inlet to Flare (tpy) x (100 - Flare DRE (%))/100

Example Controlled Methane Annual Emission Rate (tpy) = 0,003 ton / yr | (100 - 99%) / 100 = 0.03 tpy

[5] Per 40 CFR Part 98.233(z) (Subpart W), for fuel combustion units that combust process vent gas, the following equations are used to estimate the GHG emissions from additional carbon compounds in the fuel.
Hourly Emission Rate for Compounds Converted to CO_2 (lb/hr) = Inlet to Flare (lb/hr) x DRE (%)/100 x Carbon Count (#)

Example Converted Methane Hourly Emission Rate (lb/hr) = 325.72 lb / hr | 99% / 100 | 1 = 322.46 lb/hr

[6] Annual Emission Rate for Compounds Converted to CO_2 (tpy) = Inlet to Flare (tpy) x DRE (%)/100 x Carbon Count (#)

Example Converted Methane Annual Emission Rate (tpy) = 0,003 ton / yr | 99% / 100 | 1 = 2.49 tpy

[7] CO_2e Hourly Emission Rate (lb/hr) = CO_2 Emission Rate (lb/hr) x CO_2 GWP + CH_4 Emission Rate (lb/hr) x CH_4 GWP + N_2O Emission Rate (lb/hr) x N_2O GWP

Example CO_2e Hourly Emission Rate (lb/hr) = 41,465.66 lb / hr | 1 + 3.26 lb / hr | 21 + 1.37E-03 lb / hr | 310 = 41,534.48 lb/hr

Targa Midstream Services LLC - Mont Belvieu Plant
Shutdown Emissions Released to Atmosphere Calculations

Emissions Calculations

FIN	EPN	Source Name	VOC Emissions (lb/hr)	VOC Emissions [1] (tpy)
Shutdown	Shutdown	Shutdown Vapor Emissions to Atmosphere	10.52	0.07
Emissions			10.52	0.07

[1] VOC Emissions (tpy) = Total VOC Weight Per Year (lb/yr) x 1 / 2,000 (ton/lb)

$$\text{VOC Emissions (tpy)} = \frac{139.06\ \text{lb}}{\text{yr}} \left| \frac{1\ \text{ton}}{2{,}000\ \text{lb}} \right. = 0.07\ \text{tpy}$$

Component Molecular Weights

Component	MW (lb/lb-mol)
C1	16.04
C2	30.07
C3	44.10
iC4	58.12
C4	58.12
iC5	72.15
C5	72.15
C6	86.18
C7	100.21

Targa Midstream Services LLC - Mont Belvieu Plant
Shutdown Emissions Released to Atmosphere Calculations

Uncontrolled Shutdown Parameters

Unit ID	Description	Hours Per Event (hr/event)	Frequency per Year (event/yr)	ID (ft)	Height (ft)	Total Volume (ft^3)	Total Volume[1] (ft^3/hr)	Molar VOC Content[2,3] (lb-mol/yr)	Vapor Mass Fraction[4] C1	C2	C3	iC4	C4	iC5	C5	C6	C7
Pressure Vessels																	
31-358-1 Deeth	DC2	12	1	16	126	28,551	2,379	0.75	0.0633	0.8119	0.0947	0.0146	0.0107	0.0023	0.0014	0.0002	0.0009
30-358-1	DC2 Reflux Accum	12	1	10	50	4,712	393	0.12	0.0375	0.9559	0.0066	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
30-358-4	C2 Comp suct scrub	2	1	6.5	10	548	274	0.01	0.0375	0.9559	0.0066	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
30-358-6	Refrig comp suct scrub	2	1	8	10	905	452	0.02	0.0000	0.1798	0.8117	0.0078	0.0007	0.0000	0.0000	0.0000	0.0000
30-358-7	Refrig Accumulator	10	1	8	24	1,608	161	0.04	0.0000	0.1798	0.8117	0.0078	0.0007	0.0000	0.0000	0.0000	0.0000
31-358-4	DC3	12	1	13	114	16,857	1,405	0.44	0.0000	0.1606	0.6561	0.0616	0.0994	0.0113	0.0076	0.0005	0.0029
30-358-9	DC3 Reflux Accum	12	1	10	40	3,927	327	0.10	0.0000	0.1798	0.8117	0.0078	0.0007	0.0000	0.0000	0.0000	0.0000
30-358-401A/B	C3 COS Reactors	2	1	6	30	1,018	509	0.03	0.0000	0.1798	0.8117	0.0078	0.0007	0.0000	0.0000	0.0000	0.0000
30-358-402A/B	C3 H2S Reactors	2	1	7	34	1,578	789	0.04	0.0000	0.1798	0.8117	0.0078	0.0007	0.0000	0.0000	0.0000	0.0000
31-358-5	DC4	12	1	9.5	98	7,620	635	0.20	0.0000	0.0000	0.0094	0.3190	0.5550	0.0604	0.0398	0.0023	0.0141
30-358-10	DC4 Reflux accum	12	1	8.5	30	2,185	182	0.06	0.0000	0.0000	0.0104	0.3604	0.6281	0.0011	0.0000	0.0000	0.0000
31-358-6	C4 Splitter	12	1	12	212	25,334	2,111	0.67	0.0000	0.0000	0.0104	0.3604	0.6281	0.0011	0.0000	0.0000	0.0000
30-358-11	C4 Splitter comp K.O.	10	1	6.5	16	747	75	0.02	0.0000	0.0000	0.0294	0.9578	0.0127	0.0000	0.0000	0.0000	0.0000
30-358-12	C4 Splitter Reflux accum	12	1	8.5	40	2,752	229	0.07	0.0000	0.0000	0.0294	0.9578	0.0127	0.0000	0.0000	0.0000	0.0000
30-358-501A/B/C	Gasoline treaters	12	1	8	16	3,619	302	0.10	0.0000	0.0000	0.0000	0.0003	0.0291	0.5036	0.3338	0.0189	0.1143
30-358-502A/B/C	Caustic separators	10	1	6	20	2,205	221	0.06	0.0000	0.0000	0.0000	0.0003	0.0291	0.5036	0.3338	0.0189	0.1143
30-358-601A/B	Caustic Contactors	10	1	12	50	14,024	1,402	0.37	0.0000	0.0000	0.0000	0.0003	0.0291	0.5036	0.3338	0.0189	0.1143
30-358-602A/B	Caustic Settlers	10	1	6	30	2,036	204	0.05	0.0000	0.0000	0.0000	0.0003	0.0291	0.5036	0.3338	0.0189	0.1143
Pipelines																	
	RP	8	1	0.83	3,800	2,487	311	0.07	0.0633	0.8119	0.0947	0.0146	0.0107	0.0023	0.0014	0.0002	0.0009
	C2	8	1	0.83	3,800	2,487	311	0.07	0.0375	0.9559	0.0066	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	C3	8	1	0.67	3,800	1,990	249	0.05	0.0000	0.1798	0.8117	0.0078	0.0007	0.0000	0.0000	0.0000	0.0000
	iC4	8	1	0.5	3,800	1,492	187	0.04	0.0000	0.0000	0.0294	0.9578	0.0127	0.0000	0.0000	0.0000	0.0000
	nC4	8	1	0.5	3,800	1,492	187	0.04	0.0000	0.0000	0.0000	0.0401	0.9581	0.0017	0.0001	0.0000	0.0000
	C5+	8	1	0.5	3,800	1,492	187	0.04	0.0000	0.0000	0.0000	0.0003	0.0291	0.5036	0.3338	0.0189	0.1143
Filters/Coalescers																	
15-358-1A/B	Plant inlet feed filters	1	1	3	7.25	51	51	1.35E-03	0.0633	0.8119	0.0947	0.0146	0.0107	0.0023	0.0014	0.0002	0.0009
15-358-2A/B	Plant feed inlet coalescers	1	1	5	5.25	103	103	2.72E-03	0.0633	0.8119	0.0947	0.0146	0.0107	0.0023	0.0014	0.0002	0.0009
15-358-401	Treated Propane Filter Coalescer	1	1	3	5.25	37	37	9.78E-04	0.0000	0.1798	0.8117	0.0078	0.0007	0.0000	0.0000	0.0000	0.0000
15-358-501	Treated gasoline coalescer	1	1	2.33	5.25	22	22	5.92E-04	0.0000	0.0000	0.0000	0.0003	0.0291	0.5036	0.3338	0.0189	0.1143
15-358-601	n-butane product coalescer	1	1	3	5.25	37	37	9.78E-04	0.0000	0.0000	0.0000	0.0401	0.9581	0.0017	0.0001	0.0000	0.0000
Pumps																	
28-358-1A/B	DC2 Reflux Pumps	1	1	-	-	11.24	11	2.96E-04	0.0375	0.9559	0.0066	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
28-358-2A/B	DC3 Reflux Pumps	1	1	-	-	11.24	11	2.96E-04	0.0000	0.1798	0.8117	0.0078	0.0007	0.0000	0.0000	0.0000	0.0000
28-358-3A/B	C3 Inject pumps	1	1	-	-	11.24	11	2.96E-04	0.0000	0.1798	0.8117	0.0078	0.0007	0.0000	0.0000	0.0000	0.0000
28-358-4A/B	DC4 Reflux pumps	1	1	-	-	11.24	11	2.96E-04	0.0000	0.0000	0.0104	0.3604	0.6281	0.0011	0.0000	0.0000	0.0000
28-358-5A/B	Gasoline booster pumps	1	1	-	-	11.24	11	2.96E-04	0.0000	0.0000	0.0000	0.0003	0.0291	0.5036	0.3338	0.0189	0.1143
28-358-6A/B	Gasoline injection pumps	1	1	-	-	11.24	11	2.96E-04	0.0000	0.0000	0.0000	0.0003	0.0291	0.5036	0.3338	0.0189	0.1143
28-358-7A/B	C4 split bottoms pumps	1	1	-	-	11.24	11	2.96E-04	0.0000	0.0000	0.0294	0.9578	0.0127	0.0000	0.0000	0.0000	0.0000
28-358-8A/B	C4 split reflux pumps	1	1	-	-	11.24	11	2.96E-04	0.0000	0.0000	0.0000	0.0401	0.9581	0.0017	0.0001	0.0000	0.0000
28-358-9A/B	C4 Split comp K.O. drum pumps	1	1	-	-	11.24	11	2.96E-04	0.0000	0.0000	0.0294	0.9578	0.0127	0.0000	0.0000	0.0000	0.0000
28-358-10A/B	iC4 injection pumps	1	1	-	-	11.24	11	2.96E-04	0.0000	0.0000	0.0294	0.9578	0.0127	0.0000	0.0000	0.0000	0.0000
28-358-11A/B	nC4 injection pumps	1	1	-	-	11.24	11	2.96E-04	0.0000	0.0000	0.0000	0.0401	0.9581	0.0017	0.0001	0.0000	0.0000
Compressors																	
11-358-1A/B	Ethane	1	1	-	-	2,000	2,000	0.05	0.0375	0.9559	0.0066	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
11-358-2A/B	Refrigeration	2	1	-	-	1,200	600	0.03	0.0000	0.1798	0.8117	0.0078	0.0007	0.0000	0.0000	0.0000	0.0000
11-358-3	C4 Splitter	3	1	-	-	1,000	333	0.03	0.0000	0.0000	0.0294	0.9578	0.0127	0.0000	0.0000	0.0000	0.0000

[1] Total Volume (ft^3/hr) = Total Volume (ft^3/event) / Hours Per Event (hr/event)

Pressure Vessel 31-358-1 Deeth C3 Total Volume (ft^3/hr) = $\frac{28{,}551 \text{ ft3}}{\text{event}} \Big| \frac{\text{event}}{12 \text{ hr}}$ = 2,379 ft3/hr

[2] Emission calculations are based on a VOC content of 10,000 ppmv

[3] Molar VOC Content (lb-mol/yr) = (Frequency/Year) / (379.5 scf/lb-mol) x Total Volume (ft^3/event) x VOC Concentration (ppmv) / 1,000,000

Pressure Vessel 31-358-1 Deeth C3 Molar VOC Content (lb-mol/yr) = $\frac{1 \text{ event}}{\text{yr}} \Big| \frac{\text{lb-mol}}{379.5 \text{ scf}} \Big| \frac{28{,}551 \text{ ft3}}{\text{event}} \Big| \frac{10{,}000 \text{ ppmv}}{1{,}000{,}000}$ = 0.75 lb-mol/yr

[4] The mass fraction ratio of n-hexane to n-hexane and higher is 14.2 %

Uncontrolled Shutdown Emissions

Unit ID [1]	Description [1]	Emission Groups [1]	Uncontrolled Weight Per Hour (lb/hr) [2]									Uncontrolled Weight Per Year (lb/yr) [3]								
			C1	C2	C3	iC4	C4	iC5	C5	C6	C7	C1	C2	C3	iC4	C4	iC5	C5	C6	C7
Pressure Vessels																				
31-358-1 Deeth	DC2	M	6.3635	153.0528	0.26	0.05	0.04	0.01	6.43E-03	8.20E-04	5.76E-03	76.36	1836.63	3.14	0.64	0.47	0.12	0.08	9.84E-03	0.07
30-358-1	DC2 Reflux Accum	M	0.6233	29.7413	3.01E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	7.48	356.90	0.04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
30-358-4	C2 Comp suct scrub	M	0.4345	20.7334	2.10E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.87	41.47	4.20E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
30-358-6	Refrig comp suct scrub	N	0.0000	6.4453	0.43	5.41E-03	4.98E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	12.89	0.85	0.01	9.95E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00
30-358-7	Refrig Accumulator	N	0.0000	2.2916	0.15	1.92E-03	1.77E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	22.92	1.52	0.02	1.77E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00
31-358-4	DC3	O	0.0000	17.8791	1.07	0.13	0.21	0.03	0.02	1.51E-03	0.01	0.00E+00	214.55	12.85	1.59	2.57	0.36	0.24	0.02	0.13
30-358-9	DC3 Reflux Accum	O	0.0000	4.6624	0.31	3.92E-03	3.60E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	55.95	3.70	0.05	4.32E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00
30-358-401A/B	C3 COS Reactors	P	0.0000	7.2509	0.48	6.09E-03	5.60E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	14.50	0.96	0.01	1.12E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00
30-358-402A/B	C3 H2S Reactors	P	0.0000	11.2400	0.74	9.44E-03	8.68E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	22.48	1.49	0.02	1.74E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00
31-358-5	DC4	Q	0.0000	0.0000	6.92E-03	0.31	0.54	0.07	0.05	3.36E-03	0.02	0.00E+00	0.00E+00	0.08	3.72	6.48	0.88	0.58	0.04	0.28
30-358-10	DC4 Reflux accum	Q	0.0000	0.0000	2.20E-03	0.10	0.18	3.89E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.03	1.21	2.10	4.67E-03	0.00E+00	0.00E+00	0.00E+00
31-358-6	C4 Splitter	Q	0.0000	0.0000	0.03	1.17	2.03	4.51E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.31	13.98	24.37	0.05	0.00E+00	0.00E+00	0.00E+00
30-358-11	C4 Splitter comp K.O.	Q	0.0000	0.0000	2.55E-03	0.11	1.45E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.03	1.10	0.01	0.00E+00	0.00E+00	0.00E+00	0.00E+00
30-358-12	C4 Splitter Reflux accum	Q	0.0000	0.0000	7.85E-03	0.34	4.46E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.09	4.04	0.05	0.00E+00	0.00E+00	0.00E+00	0.00E+00
30-358-501A/B/C	Gasoline treaters	Q	0.0000	0.0000	0.00E+00	1.54E-04	0.01	0.29	0.19	0.01	0.09	0.00E+00	0.00E+00	0.00E+00	1.85E-03	0.16	3.46	2.30	0.16	1.09
30-358-502A/B/C	Caustic separators	Q	0.0000	0.0000	0.00E+00	1.13E-04	9.82E-03	0.21	0.14	9.47E-03	0.07	0.00E+00	0.00E+00	0.00E+00	1.13E-03	0.10	2.11	1.40	0.09	0.67
30-358-601A/B	Caustic Contactors	Q	0.0000	0.0000	0.00E+00	7.18E-04	0.06	1.34	0.89	0.06	0.42	0.00E+00	0.00E+00	0.00E+00	7.18E-03	0.62	13.43	8.90	0.60	4.23
30-358-602A/B	Caustic Settlers	Q	0.0000	0.0000	0.00E+00	1.04E-04	9.06E-03	0.19	0.13	8.74E-03	0.06	0.00E+00	0.00E+00	0.00E+00	1.04E-03	0.09	1.95	1.29	0.09	0.61
Pipelines			0.0000	0.0000								0.00E+00	0.00E+00							
	RP	-	0.8315	19.9989	0.03	6.94E-03	5.11E-03	1.35E-03	8.40E-04	1.07E-04	7.53E-04	6.65	159.99	0.27	0.06	0.04	0.01	6.72E-03	8.57E-04	6.02E-03
	C2	-	0.4934	23.5452	2.38E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.95	188.36	0.02	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	C3	-	0.0000	3.5434	0.23	2.98E-03	2.74E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	28.35	1.88	0.02	2.19E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	iC4	-	0.0000	0.0000	6.38E-03	0.27	3.63E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.05	2.19	0.03	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	nC4	-	0.0000	0.0000	0.00E+00	0.01	0.27	6.00E-04	2.86E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.09	2.19	4.80E-03	2.29E-04	0.00E+00	0.00E+00
	C5+	-	0.0000	0.0000	0.00E+00	9.55E-05	8.30E-03	0.18	0.12	8.01E-03	0.06	0.00E+00	0.00E+00	0.00E+00	7.64E-04	0.07	1.43	0.95	0.06	0.45
Filters/Coalescers			0.0000	0.0000								0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
15-358-1A/B	Plant inlet feed filters	-	0.1371	3.2967	5.64E-03	1.14E-03	8.43E-04	2.23E-04	1.38E-04	1.77E-05	1.24E-04	0.14	3.30	5.64E-03	1.14E-03	8.43E-04	2.23E-04	1.38E-04	1.77E-05	1.24E-04
15-358-2A/B	Plant feed inlet coalescers	-	0.2757	6.6312	0.01	2.30E-03	1.70E-03	4.49E-04	2.79E-04	3.55E-05	2.50E-04	0.28	6.63	0.01	2.30E-03	1.70E-03	4.49E-04	2.79E-04	3.55E-05	2.50E-04
15-358-401	Treated Propane Filter Coalescer	-	0.0000	0.5287	0.04	4.44E-04	4.08E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.53	0.04	4.44E-04	4.08E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00
15-358-501	Treated gasoline coalescer	-	0.0000	0.0000	0.00E+00	1.15E-05	9.99E-04	0.02	0.01	9.64E-04	6.77E-03	0.00E+00	0.00E+00	0.00E+00	1.15E-05	9.99E-04	0.02	0.01	9.64E-04	6.77E-03
15-358-601	n-butane product coalescer	-	0.0000	0.0000	0.00E+00	2.28E-03	0.05	1.19E-04	5.69E-06	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.28E-03	0.05	1.19E-04	5.69E-06	0.00E+00	0.00E+00
Pumps		-	0.0000	0.0000								0.00E+00	0.00E+00							
28-358-1A/B	DC2 Reflux Pumps	-	0.0178	0.8510	8.61E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.02	0.85	8.61E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
28-358-2A/B	DC3 Reflux Pumps	-	0.0000	0.1601	0.01	1.34E-04	1.24E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.16	0.01	1.34E-04	1.24E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00
28-358-3A/B	C3 Inject pumps	-	0.0000	0.1601	0.01	1.34E-04	1.24E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.16	0.01	1.34E-04	1.24E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00
28-358-4A/B	DC4 Reflux pumps	-	0.0000	0.0000	1.36E-04	6.20E-03	0.01	2.40E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.36E-04	6.20E-03	0.01	2.40E-05	0.00E+00	0.00E+00	0.00E+00
28-358-5A/B	Gasoline booster pumps	-	0.0000	0.0000	0.00E+00	5.75E-06	5.00E-04	0.01	7.13E-03	4.83E-04	3.39E-03	0.00E+00	0.00E+00	0.00E+00	5.75E-06	5.00E-04	0.01	7.13E-03	4.83E-04	3.39E-03
28-358-6A/B	Gasoline injection pumps	-	0.0000	0.0000	0.00E+00	5.75E-06	5.00E-04	0.01	7.13E-03	4.83E-04	3.39E-03	0.00E+00	0.00E+00	0.00E+00	5.75E-06	5.00E-04	0.01	7.13E-03	4.83E-04	3.39E-03
28-358-7A/B	C4 split bottoms pumps	-	0.0000	0.0000	3.84E-04	0.02	2.19E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.84E-04	0.02	2.19E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00
28-358-8A/B	C4 split reflux pumps	-	0.0000	0.0000	0.00E+00	6.90E-04	0.02	3.62E-05	1.72E-06	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	6.90E-04	0.02	3.62E-05	1.72E-06	0.00E+00	0.00E+00
28-358-9A/B	C4 Split comp K.O. drum pumps	-	0.0000	0.0000	3.84E-04	0.02	2.19E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.84E-04	0.02	2.19E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00
28-358-10A/B	iC4 injection pumps	-	0.0000	0.0000	3.84E-04	0.02	2.19E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.84E-04	0.02	2.19E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00
28-358-11A/B	nC4 injection pumps	-	0.0000	0.0000	0.00E+00	6.90E-04	0.02	3.62E-05	1.72E-06	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	6.90E-04	0.02	3.62E-05	1.72E-06	0.00E+00	0.00E+00
Compressors			0.0000	0.0000								0.00E+00	0.00E+00							
11-358-1A/B	Ethane	-	3.1744	151.4714	0.02	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.17	151.47	0.02	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
11-358-2A/B	Refrigeration	-	0.0000	8.5483	0.57	7.18E-03	6.60E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	17.10	1.13	0.01	1.32E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00
11-358-3	C4 Splitter	-	0.0000	0.0000	0.01	0.49	6.49E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.03	1.47	0.02	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Emissions [4]			7.42	203.53	1.38	2.02	2.85	2.12	1.40	0.09	0.67	98.91	3135.18	28.57	30.30	39.49	23.86	15.77	1.08	7.55

[1] Emission calculations are based on a VOC content of 10,000 ppmv

[2] Uncontrolled Weight Per Hour (lb/hr) = Total Volume Rate (ft^3/hr) / 379.5 (scf/lb-mol) x Vapor Mass Fraction x Component Molecular Weight (lb/lb-mol) x VOC Concentration (ppmv) / 1,000,000

Pressure Vessel 31-358-1 Deeth C3 Weight Per Hour (lb/hr) = 2,379 ft3 / hr | lb-mol / 379.5 scf | 0.09 | 44.1 lb / lb-mol | 10,000 ppmv / 1,000,000 = 0.26 lb/hr

Uncontrolled Weight Per Hour for C1 and C2 (lb/hr) = Total Volume Rate (ft^3/hr) / 379.5 (scf/lb-mol) x Vapor Mass Fraction x Component Molecular Weight (lb/lb-mol)

Pressure Vessel 31-358-1 Deeth C3 Weight Per Hour (lb/hr) = 2,379 ft3 / hr | lb-mol / 379.5 scf | 0.063 | 16.04 lb / lb-mol = 6.3635 lb/hr

[3] Uncontrolled Weight Per Year (lb/yr) = Component Molecular Weight (lb/lb-mol) x Molar VOC Content (lb-mol/yr) x VOC Vapor Mass Fraction

Pressure Vessel 31-358-1 Deeth C3 Weight Per Year (lb/yr) = 44.1 lb / lb-mol | 7.52E-01 lbmol / yr | 0.09 / yr = 3.14 lb/yr

Uncontrolled Weight Per Year for C1 and C2 (lb/yr) = Uncontrolled Weight Per Hour (lb/hr) x Hours Per Event (hr/event) x Frequency per Year (event/yr)

Filter/Coalescers 15-358-1A/Bs C3 Weight Per Year (lb/yr) = 6.3635 lb / hr | 12 hr / event | 1 event / yr = 76.36 lb/yr

[4] Each of the pipelines, filters/coalescers, pumps, compressors, and pressure vessels groups occur at separate instances. Therefore, hourly emissions are based on the maximum emissions for the sum of the emissions of Group M, N, O. P, Q, and each of the remaining units.

GHG Emissions

Global Warming Potentials [1]

CO_2	CH_4	N_2O
1	21	310

[1] Global warming potentials (GWP) obtained from 40 CFR 98 Subpart A Table A-1.

Speciated GHG Emissions - Atmosphere

Gas Stream	Compound	GHG Emissions[1,2]		Converted to CO_2e [3]	
		(lb/hr)	(tpy)	(lb/hr)	(tpy)
Emissions to Atmosphere	Methane	7.42	0.05	155.85	1.04

[1] GHG Emissions (tpy) = Uncontrolled Weight Per Year (lb/yr) / 2000 lb/ton

Example Controlled Methane Annual Emission Rate (tpy) = $\frac{98.91 \text{ lb}}{\text{yr}} \times \frac{1 \text{ ton}}{2{,}000 \text{ lb}}$ = 0.05 tpy

[2] CO_2e Hourly Emission Rate (lb/hr) = CH_4 Emission Rate (lb/hr) x CH_4 GWP

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{7.42 \text{ lb}}{\text{hr}} \times 21$ = 155.85 lb/hr

Targa Midstream Services LLC - Mont Belvieu Plant
Pilot Gas & Supplemental Fuel Flare Calculations

Input Data - Pilot Gas

Gas Stream Heat Value =	1,015	Btu/scf
Number of Pilots =	4	
Average Flowrate =	50	scf/hr-pilot
Maximum Flowrate =	0.833	scfm/pilot
Hourly Flowrate [1] =	200	scf/hr
Hours of Operation =	8,760	hrs/yr
Annual Flowrate [2] =	1.752	MMscf/yr
Gas Stream Heat Input [3] =	0.20	MMBtu/hr
Gas Stream Heat Input [4] =	1,778	MMBtu/yr

Input Data - Supplemental Fuel

Supplemental Fuel =	6.75	MMBtu/hr
Supplemental Fuel =	59,098	MMBtu/yr

Compound	Flare Emission Factors [5] (lb/MMBtu)	Pilot Emissions [6, 7]	
		(lb/hr)	(tpy)
NO_x	0.138	0.03	0.12
CO	0.2755	0.06	0.24

Compound	Flare Emission Factors [5] (lb/MMBtu)	Supplemental Fuel Emissions [6, 7]	
		(lb/hr)	(tpy)
NO_x	0.0641	0.43	1.89
CO	0.5496	3.71	16.24

[1] Hourly Flowrate (scf/hr) = Average Flowrate (scf/hr-pilot) x Number of Pilots

Hourly Flowrate (scf/hr) = $\frac{50.0 \text{ scf}}{\text{hr-pilot}} \times 4 = \frac{200 \text{ scf}}{\text{hr}}$

[2] Annual Flowrate (MMscf/yr) = Hourly Flowrate (scf/hr) x Annual Operation (hr/yr) x (1 MMscf /10^6 scf)

Annual Flowrate (MMscf/yr) = $\frac{200 \text{ scf}}{\text{hr}} \times \frac{8{,}760 \text{ hr}}{\text{yr}} \times \frac{1 \text{ MMscf}}{10^6 \text{ scf}} = \frac{1.752 \text{ MMscf}}{\text{yr}}$

[3] Hourly Gas Stream Heat Input (MMBtu/hr) = Hourly Flowrate (scf/hr) x Gas Stream Heat Value (Btu/scf) x (1 MMscf /10^6 scf)

Example Hourly Gas Stream Heat Input (MMBtu/hr) = $\frac{200 \text{ scf}}{\text{hr}} \times \frac{1{,}015 \text{ Btu}}{\text{scf}} \times \frac{1 \text{ MMBtu}}{10^6 \text{ Btu}} \quad \frac{0.20 \text{ MMBtu}}{\text{hr}}$

[4] Annual Gas Stream Heat Input (MMBtu/yr) = Hourly Gas Stream Heat Input (MMBtu/hr) x Hours of Operation (hrs/yr)

Example Annual Gas Stream Heat Input (MMBtu/yr) = $\frac{0.20 \text{ MMBtu}}{\text{hr}} \times \frac{8{,}760 \text{ hrs}}{\text{yr}} = \frac{1{,}778 \text{ MMBtu}}{\text{yr}}$

[5] Pilot gas emissions from TCEQ "Air Permit Guidance For Chemical Sources, Flare And Vapor Oxidizers" (Draft Oct. 2000) Table 4, emission factors for industrial flares combusting high-Btu vapors.
Supplemental fuel emissions from TCEQ "Air Permit Guidance For Chemical Sources, Flare And Vapor Oxidizers" (Draft Oct. 2000) Table 4, emission factors for industrial flares combusting low-Btu vapors, since the supplemental fuel will be mixed with the amine and dehydrator waste gases and the mixture will be 300 Btu/scf.

[6] Maximum Potential Hourly Emission Rate (lb/hr) = Flare Emission Factor (lb/MMBtu) x Gas Stream Heat Input (MMBtu/hr)

Example NO_x Hourly Emission Rate (lb/hr) = $\frac{0.138 \text{ lb}}{\text{MMBtu}} \times \frac{0.20 \text{ MMBtu}}{\text{hr}} = \frac{0.03 \text{ lb}}{\text{hr}}$

[7] Maximum Potential Annual Emission Rate (tpy) = Flare Emission Factor (lb/MMBtu) x Gas Stream Heat Input (MMBtu/yr) x (1 ton / 2,000 lb)

Example NO_x Annual Emission Rate (tpy) = $\frac{0.138 \text{ lb}}{\text{MMBtu}} \times \frac{1{,}778 \text{ MMBtu}}{\text{yr}} \times \frac{1 \text{ ton}}{2{,}000 \text{ lb}} = \frac{0.12 \text{ ton}}{\text{yr}}$

Flare Emissions - Pilot Gas & Supplemental Fuel - VOC

Input Data

Gas Stream Heat Value =	1,015	Btu/scf
Number of Pilots =	4	
Average Flowrate =	50	scf/hr-pilot
Maximum Flowrate =	0.833	scfm/pilot
Hourly Flowrate [1] =	200	scf/hr
Hours of Operation =	8,760	hrs/yr
Annual Flowrate [2] =	1.752	MMscf/yr

Input Data - Supplemental Fuel

Supplemental Fuel =	6,646.65	scf/hr
Hours of Operation =	8,760	hrs/yr
Supplemental Fuel =	58.22	MMscf/yr

Compound	Composition [3] (wt %)	MW (lb/lb-mole)	DRE [4] (%)	Gas Vented to Flare [5] (lb/hr)	Gas Vented to Flare [5] (tpy)	Controlled Emissions [6,7] (lb/hr)	Controlled Emissions [6,7] (tpy)
Propane	0.71	44.10	99%	5.64	24.72	0.06	0.25
i-Butane	0.23	58.12	98%	2.38	10.42	0.05	0.21
n-Butane	0.21	58.12	98%	2.17	9.49	0.04	0.19
i-Pentane	0.15	72.15	98%	1.97	8.63	0.04	0.17
n-Pentane	0.08	72.15	98%	0.99	4.32	0.02	0.09
n-Hexane	0.43	86.18	98%	6.64	29.07	0.13	0.58
VOC [8]	1.80	-	0.98	19.78	86.66	0.34	1.49

[1] Hourly Flowrate (scf/hr) = Average Flowrate (scf/hr-pilot) x Number of Pilots

Hourly Flowrate (scf/hr) = $\frac{50.0\ scf}{hr\text{-}pilot} \times 4 = \frac{200\ scf}{hr}$

[2] Annual Flowrate (MMscf/yr) = Hourly Flowrate (scf/hr) x Annual Operation (hr/yr) x (1 MMscf /10^6 scf)

Annual Flowrate (MMscf/yr) = $\frac{200\ scf}{hr} \times \frac{8{,}760\ hr}{yr} \times \frac{1\ MMscf}{10^6\ scf} = \frac{1.752\ MMscf}{yr}$

[3] Composition of the gas stream is based on similar operations at the facility.

[4] Per TCEQ Air Permits Division, *Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers* , RG-109 (Draft), October 2000.

[5] Gas Vented to Flare (lb/hr) = (Pilot Gas Hourly Flowrate (scf/hr) + Supplemental Fuel Hourly Flowrate (scf/hr)) x Mole Percent / 100 x MW (lb/lb-mole) / 379.5 (scf/lb-mole)

Example Propane Hourly Emission Rate (lb/hr) = $\frac{200\ scf}{hr} + \frac{6{,}646.65\ scf}{hr} \times \frac{0.71\ \%}{100} \times \frac{44.10\ lb}{lb\text{-}mole} \times \frac{lb\text{-}mole}{379.5\ scf} = \frac{5.64\ lb}{hr}$

[6] Annual Emissions (tpy) = Hourly Emissions (lb/yr) x Hours of Operation (hrs/yr) x (1 ton / 2,000 lb)

Example Propane Vented to Flare Annual Emission Rate (tpy) = $\frac{5.64\ lb}{hr} \times \frac{8{,}760\ hrs}{yr} \times \frac{1\ ton}{2{,}000\ lb} = \frac{24.72\ ton}{yr}$

[7] Controlled Maximum Potential Hourly Emission Rate (lb/hr) = Gas Vented to Flare (lb/hr) x (100 - DRE(%))/100

Example Controlled Propane Hourly Emission Rate (lb/hr) = $\frac{5.64\ lb}{hr} \times \frac{(100 - 99\%)}{100} = \frac{0.06\ lb}{hr}$

[8] Total VOC taken as the sum of NMNEHC.

Flare Emissions - Pilot Gas & Supplemental Fuel - Greenhouse Gases

Input Data

Pilot Gas =	0.203	MMBtu/hr
Supplemental Fuel =	6.75	MMBtu/hr
Hours of Operation =	8,760	hr/yr

Natural Gas External Combustion Greenhouse Gas Emission Factors [1]

Units [2]	CO_2	CH_4	N_2O
kg/MMBtu	53.02	1.00E-03	1.00E-04
GWP [3]	1	21	310
lb/MMBtu [4]	116.89	2.20E-03	2.20E-04

[1] Per 40 CFR Part 98.233(z)(1) (Subpart W), if the fuel combusted in the stationary or portable equipment is listed in Table C-1 of Subpart C, then emissions are calculated per Subpart C.
[2] Emission factors obtained from 40 CFR 98 Subpart C Tables C-1 and C-2 for natural gas.
[3] Global warming potentials (GWP) obtained from 40 CFR 98 Subpart A Table A-1.
[4] Emission factors converted from kg/MMBtu to lb/MMBtu using the following conversion:
Greenhouse Gas Emission Factor (lb/MMBtu) = Greenhouse Gas Emission Factor (kg/MMBtu) x 2.2046 (lb/kg)

Example CO_2 Emission Factor (lb/MMBtu) = $\frac{53.02\ \text{kg}}{\text{MMBtu}} \Big| \frac{2.2046\ \text{lb}}{\text{kg}} = \frac{116.89\ \text{lb}}{\text{MMBtu}}$

Compound	Flare Emissions [1, 2, 3]	
	(lb/hr)	(tpy)
CO_2	812.31	3,557.92
CH_4	0.02	0.07
N_2O	1.53E-03	6.70E-03
CO_2e	813.10	3,561.40

[1] Maximum Potential Hourly Emission Rate (lb/hr) = (Pilot Gas (MMBtu/hr) + Supplemental Fuel (MMBtu/hr)) x Emission Factor (lb/MMBtu)

Example CO_2 Hourly Emission Rate (lb/hr) = $\frac{(0.20 + 6.75)\ \text{MMBtu}}{\text{hr}} \Big| \frac{53.02\ \text{lb}}{\text{MMBtu}} = \frac{812.31\ \text{lb}}{\text{hr}}$

[2] Maximum Potential Annual Emission Rate (tpy) = Hourly Emission Rate (lb/hr) x Hours of Operation (hr/yr) x (1 ton / 2,000 lb)

Example CO_2 Annual Emission Rate (tpy) = $\frac{812.31\ \text{lb}}{\text{hr}} \Big| \frac{8{,}760\ \text{hr}}{\text{yr}} \Big| \frac{1\ \text{ton}}{2{,}000\ \text{lb}} = \frac{3{,}558\ \text{ton}}{\text{yr}}$

[3] CO_2e emissions based on GWPs for each greenhouse gas pollutant.
CO_2e Hourly Emission Rate (lb/hr) = CO_2 Emission Rate (lb/hr) x CO_2 GWP + CH_4 Emission Rate (lb/hr) x CH_4 GWP + N_2O Emission Rate (lb/hr) x N_2O GWP

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{812.31\ \text{lb}}{\text{hr}} \Big| 1 + \frac{0.02\ \text{lb}}{\text{hr}} \Big| 21 + \frac{1.53\text{E-}03\ \text{lb}}{\text{hr}} \Big| 310 = \frac{813.10\ \text{lb}}{\text{hr}}$

Targa Midstream Services LLC - Mont Belvieu Plant
Supplemental Fuel to FLR-5

	Dehydrator Waste Stream	Amine Waste Stream
Net HV (Btu/ft^3)	381.36	96.49
Flow Rate (ft^3/hr)	1,830.68	24,084.04
Heat Rate (Btu/hr)	698,152.00	2.32E+06
Heat Rate (MMBtu/hr)	0.70	2.32
Heat Rate (Btu/yr)	6.12E+09	2.04E+10
Heat Rate (MMBtu/yr)	6,115.81	20,357.48

	Supplemental Fuel	Total [1]
Net HV (Btu/ft^3)	1,015.00	300.00
Flow Rate (ft^3/hr)	6,646.65	32,561.38
Heat Rate (Btu/hr)	6.75E+06	9.77E+06
Heat Rate (Btu/yr)	5.91E+10	8.56E+10

[1] Total Net HV represents minimum value based on NSPS 60.18.

8. EMISSION POINT SUMMARY (TCEQ TABLE 1(A))

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	March 2012	**Permit No.:**	TBD	**Regulated Entity No.:**	RN100222900
Area Name:	Mont Belvieu Fractionator			**Customer Reference No.:**	CN601301559

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) Pounds per hour	(B) TPY
FLR-5	FLR-5, AU-4, TEG-2	Flare - Normal Operation	CO_2e	3,796.80	16,629.97
			CO_2	3,792.58	16,611.52
			CH_4	0.03	0.13
			N_2O	0.01	0.05
F5A	F5A	Hot Oil Heater	CO_2e	16,901.02	74,026.45
			CO_2	16,884.46	73,953.92
			CH_4	0.32	1.39
			N_2O	0.03	0.14
F5B	F5B	Hot Oil Heater	CO_2e	16,901.02	74,026.45
			CO_2	16,884.46	73,953.92
			CH_4	0.32	1.39
			N_2O	0.03	0.14
FUG-FRAC5	FUG-FRAC5	Frac5 Fugitives	CO_2e	0.53	2.33
			CO_2	2.35E-03	0.01
			CH_4	0.03	0.11
FLR-5	Maintenance	Controlled Maintenance Emissions	CO_2e	20,312.49	303.36
			CO_2	20,279.46	302.95
			CH_4	1.57	0.02
			N_2O	<0.01	<0.01
FLR-5	Startup	Controlled Startup Emissions	CO_2e	41,087.42	280.76
			CO_2	41,017.32	280.24
			CH_4	3.33	0.02
			N_2O	<0.01	<0.01
FLR-5	Shutdown	Controlled Shutdown Emissions	CO_2e	41,534.48	401.13
			CO_2	41,465.66	400.59
			CH_4	3.26	0.03
			N_2O	<0.01	<0.01
Maintenance	Maintenance	Maintenance Emissions to Atmosphere	CO_2e	66.66	0.65
			CH_4	3.17	0.03
Shutdown	Shutdown	Shutdown Emissions to Atmosphere	CO_2e	155.85	1.04
			CH_4	7.42	0.05

EPN = Emission Point Number

FIN = Facility Identification Number

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	March 2012	**Permit No.:**	TBD	**Regulated Entity No.:**	RN100222900
Area Name:	Mont Belvieu Fractionator			**Customer Reference No.:**	CN601301559

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA			EMISSION POINT DISCHARGE PARAMETERS									
1. Emission Point			4. UTM Coordinates of Emission Point			Source	6.Stack Exit Data			7. Fugitives		
EPN (A)	FIN (B)	NAME (C)	Zone	East (Meters)	North (Meters)	5. Height Above Ground (Feet)	Diameter (Feet) (A)	Velocity (FPS) (B)	Temperature (°f) (C)	Length (ft.) (A)	Width (ft.) (B)	Axis Degrees (C)
FLR-5	FLR-5, AU-4, TEG-2	Flare - Normal Operation	15	316339	3301923	185	5.5	TBD	Varies			
F5A	F5A	Hot Oil Heater	15	316375	3302012	122	4'-4" x 3'-1"	61.85	410			
F5B	F5B	Hot Oil Heater	15	316388	3302017	122	4'-4" x 3'-1"	61.85	410			
FUG-FRAC5	FUG-FRAC5	Frac5 Fugitives	15	316516	3301985	10				464.1	326.8	345
FLR-5	Maintenance	Controlled Maintenance Emissions	15	316339	3301923	185	5.5	TBD	Varies			
FLR-5	Startup	Controlled Startup Emissions	15	316339	3301923	185	5.5	TBD	Varies			
FLR-5	Shutdown	Controlled Shutdown Emissions	15	316339	3301923	185	5.5	TBD	Varies			
Shutdown	Shutdown	Shutdown Emissions to Atmosphere	15	316516	3301985	10				464.1	326.8	345
Maintenance	Maintenance	Maintenance Emissions to Atmosphere	15	316516	3301985	10				464.1	326.8	345

9. FEDERAL NEW SOURCE REVIEW REQUIREMENTS

This section addresses the applicability of the following federal new source review permitting programs to equipment for the proposed Train 5 Project:

> Nonattainment New Source Review
> Prevention of Significant Deterioration

All applicable state and federal requirements (e.g., New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP)), with the exception of those pertaining to GHG emissions, are addressed in the TCEQ minor source state NSR permit application. The TCEQ application is included in Appendix E as reference.

Under U.S. EPA and TCEQ rules, sites located in areas that are designated in attainment of the National Ambient Air Quality Standards (NAAQS) for a criteria pollutant are potentially regulated under the PSD program if they are considered major sources. Major source thresholds are defined in 40 CFR §52.21 (b)(1)(i). The Mont Belvieu Plant is considered a major source under PSD.

The Mont Belvieu Plant is located in Chambers County, which has been designated as a severe nonattainment area for the eight-hour ozone standard.[10] Volatile organic compounds (VOC) and oxides of nitrogen (NO_x) are considered to be precursors to ground-level ozone formation; therefore, nonattainment new source review (NNSR) review is required if a modification of an existing major source results in a significant net emission rate increase of a regulated pollutant. The Mont Belvieu Plant is classified as an existing major source under NNSR for NO_x and VOC.

The following sections describe the PSD and NNSR applicability analysis for the proposed project.

9.1. PSD APPLICABILITY REVIEW

The Mont Belvieu Plant is an existing major source with respect to criteria pollutants under the PSD program because potential emissions of one or more criteria pollutant exceed the thresholds listed in 40 CFR §52.21(b)(1)(i) (i.e., more than 250 tpy). PSD permitting requirements apply to a major modification at an existing major stationary source. For non-GHG pollutants, a major modification is defined in 40 CFR §52.21(b)(2)(i) as any project that would result in a significant net emissions increase of a regulated NSR pollutant, as compared to the significant emission rates (SERs) provided in §52.21(b)(23) and shown in the table below.

Table 9.1-1. Non-GHG Pollutant Significant Emission Rates

CO (tpy)	NO_2 (tpy)	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)
100	40	25	15	10	40

As shown in the table included at the end of this section, the project emission increases of all non-GHG criteria pollutants are less than their respective SERs. Therefore, the proposed project will not be subject to PSD permitting

[10] Per 40 CFR §81.344 (Effective October 31, 2008).

requirements for non-GHG criteria emissions and the project is subject to the jurisdiction of the TCEQ for minor NSR permitting of such emissions.

In the GHG Tailoring Rule, EPA established a major source threshold of 100,000 tpy CO_2e for new GHG sources and a major modification threshold of 75,000 tpy CO_2e for existing major sources.[11] The Mont Belvieu Plant is an existing major source with respect to GHG emissions under the PSD program because the site currently has a potential to emit greater than 100,000 tpy of CO_2e. Targa has determined that the increase in GHG emissions from the proposed project will exceed 75,000 tpy. As a result, Targa has concluded that the proposed project will be a major modification with respect to GHG emissions and subject to PSD permitting requirements for such emissions.

With a final action published in May 2011, EPA promulgated a FIP to implement the permitting requirements for GHGs in Texas, and EPA assumed the role of permitting authority for Texas GHG permit applications with that action.[12] Therefore, GHG emissions from the proposed project are subject to the jurisdiction of the EPA under authority EPA has asserted in Texas through its FIP for the regulation of GHGs.

Accordingly, Targa is submitting applications to both EPA and TCEQ to obtain the requisite authorizations to construct. The state minor NSR permit application submitted to TCEQ is included in Appendix E of this GHG PSD permit application for reference.

9.2. NNSR APPLICABILITY REVIEW

The Mont Belvieu Plant is an existing major source with respect to NO_x and VOC emissions under the NNSR program because sitewide emissions exceed the thresholds listed in 40 CFR §52.21(b)(1)(i) (i.e., more than 25 tpy for a facility in a severe ozone nonattainment area). NNSR applicability is determined based on the increase in emissions of NO_x and VOCs from the proposed project. The increases in VOC and NO_x emissions from the proposed project, without regard to decreases, are greater than five tpy for each pollutant; therefore, contemporaneous netting is required by 30 TAC §116.150(c).

Targa performed contemporaneous netting calculations for NO_x and VOC, taking into account creditable source emission increases and decreases during the contemporaneous period. The contemporaneous period was taken as the period between the expected start of operation of the proposed Train 5 project and 60 months prior to the expected start of construction date for the proposed project, as defined in 30 TAC §116.12(11). The netting results for each pollutant are compared to the 25 tpy threshold for the severe nonattainment designation. NNSR permitting requirements are not triggered as contemporaneous netting for both pollutants demonstrates less than a 25 tpy increase. The netting analysis is presented in a summary table and netting tables provided at the end of this section.

[11] Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, 75 Fed. Reg. 31,514 (June 3, 2010).

[12] Determinations Concerning Need for Error Correction, Partial Approval and Partial Disapproval, and Federal Implementation Plan Regarding Texas's Prevention of Significant Deterioration Program, 76 Fed. Reg. 25,178 (May 3, 2011).

Targa Midstream Services LLC - Mont Belvieu Plant
PSD & NNSR Summary

PSD Applicability Analysis [1]

			Emissions Increases for Project-Affected Sources (tpy)						
FIN	**EPN**	**Description**	**CO**	**NO_2**	**PM**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**CO_2e**
TEG-2	FLR-5	Controlled TEG-2 Emissions	1.68	0.20	-	-	-	-	1,283.79
AU-4	FLR-5	Controlled AU-4 Emissions	5.59	0.65	-	-	-	0.19	11,784.78
F5A	F5A	Hot Oil Heater	23.41	3.16	2.53	2.53	2.53	0.37	74,026.45
F5B	F5B	Hot Oil Heater	23.41	3.16	2.53	2.53	2.53	0.37	74,026.45
FUG-CT-9	FUG-CT-9	Cooling Tower 9	-	-	2.43	0.73	0.73	-	-
Maintenance	FLR-5	Controlled Maintenance Emissions	0.01	0.01	-	-	-	-	303.36
Startup	FLR-5	Controlled Startup Emissions	0.05	0.03	-	-	-	-	280.76
Shutdown	FLR-5	Controlled Shutdown Emissions	0.05	0.03	-	-	-	-	401.13
TK-2	TK-2	Ucarsol Storage Tank	-	-	-	-	-	-	-
FLR-5	FLR-5	Flare Pilot & Supplemental Fuel	16.49	2.02	-	-	-	-	3,561.40
		Total Project Emissions Increase	70.69	9.25	7.49	5.79	5.79	0.93	165,668
		PSD Significant Emission Rate	100	40	25	15	10	40	75,000
		PSD Netting Analysis Needed (Yes/No)?	No	No	No	No	No	No	Yes

[1] Fugitive emissions are not included in PSD applicability determination per 40 CFR 52.28(c)(4)(ii).

NNSR Applicability Analysis

Pollutant	**Total Project Emissions Increases (tpy)**	**Above 5 tpy Netting Threshold?**	**Net Emission Increase (tpy) [1]**	**NNSR Threshold**	**NNSR Review?**
VOC	13.20	Yes	20.32	25	No
NO_x	9.25	Yes	-2.23	25	No

[1] The net emission increase is based on the sum of the creditable increase or decrease column of Table 3F.

TCEQ

TABLE 3F

PROJECT CONTEMPORANEOUS CHANGES[1]

Company: Targa Midstream Services LLC	
Permit Application Number: N/A	**Criteria Pollutant: NO_x**

Project Date[2]		Facility at Which Emission Change Occured[3]		Permit No.	Project Name or Activity	Baseline Period	A Baseline Emissions (tons/year)	B Proposed Emissions (tons/year)	Difference (B-A)[5]	Creditable Decrease or Increase[6]
		FIN	EPN							
1	2/1/2009	F-B	F-B	85385	Furnace B Change	2004-2005	52.00	30.00	-22.00	-22.00
3	4/11/2009	B-09A	B-09A	81524	Temporary Boiler	2007-2008	7.73	-	-7.73	-7.73
4	4/11/2009	B-09B	B-09B	81524	Temporary Boiler	2007-2008	7.73	-	-7.73	-7.73
2	7/15/2009	GT-1	GT-1	84814	CoGen Permit	2007-2008	-	17.01	17.01	17.01
5	7/15/2009	B-09C	B-09C	83115	Temporary Boiler	2007-2008	4.99	-	-4.99	-4.99
6	1/20/2011	AU-1	FLR-1NSCAP	106.261	Amine Treater Temporary		-	0.24	0.24	0.24
7	2/9/2011	AU-1	FLR-1NSCAP	106.261	Amine Treater Temporary		0.24	-	-0.24	-0.24
8	3/30/2011	GLY-2	FLR-1NSCAP	91519	T-14 Expansion Project	2006-2007	-	0.20	0.20	0.20
9	3/30/2011	AU-2	FLR-1NSCAP	91519	T-14 Expansion Project	2006-2007	2.14	1.41	-0.73	-0.73
10	4/18/2011	TEMP-WASH	TEMP-WASH	106.511	Temporary Wash Pump	2009-2010	-	0.53	0.53	0.53
11	10/3/2011	RB2011A	RB2011A	98061	Rental Boiler_2011A	2009-2010	-	4.59	4.59	4.59
12	10/3/2011	RB2011B	RB2011B	98061	Rental Boiler_2011B	2009-2010	-	4.59	4.59	4.59
13	10/28/2011	TEMP-WASH	TEMP-WASH	106.511	Temporary Wash Pump	2009-2010	0.53	-	-0.53	-0.53
14	12/31/2011	RB2011A	RB2011A	98061	Rental Boiler_2011A	2009-2010	4.59	-	-4.59	-4.59
15	12/31/2011	RB2011B	RB2011B	98061	Rental Boiler_2011B	2009-2010	4.59	-	-4.59	-4.59
16	1/24/2012	GS-MSS	GS-MSS	5452	Gasoline Stabilizer		-	0.00	0.00	0.00
17	1/24/2012	GS-MSS	FLR-1NSCAP	5452	Gasoline Stabilizer		-	0.004	0.004	0.004
18	1/24/2012	BOILERS	BOILERS	5452	Gasoline Stabilizer		-	8.36	8.36	8.36
19	8/31/2012*	multiple	FLR-1NSCAP	5452	RTO Installation	2008-2009	23.09	7.00	-16.09	-16.09
20	8/31/2012*	RTO-1	RTO-1	95200	RTO Installation		-	3.85	3.85	3.85
21	8/31/2012*	RTO-2	RTO-2	95200	RTO Installation		-	0.16	0.16	0.16
22	8/31/2012*	AU-3	RTO-2	94872	Train 4 Expansion Project		-	0.16	0.16	0.16
23	5/1/2013*	H-701A	H-701A	94872	Train 4 Expansion Project		-	3.16	3.16	3.16
24	5/1/2013*	H-701B	H-701B	94872	Train 4 Expansion Project		-	3.16	3.16	3.16
25	5/1/2013*	TEG-1	RTO-1	94872	Train 4 Expansion Project		-	<0.001	<0.001	<0.001
26	5/1/2013*	Maintenance	RTO-1	94872	Train 4 Expansion Project		-	<0.001	<0.001	<0.001
27	5/1/2013*	Startup	RTO-1	94872	Train 4 Expansion Project		-	<0.001	<0.001	<0.001
28	5/1/2013*	Shutdown	RTO-1	94872	Train 4 Expansion Project		-	<0.001	<0.001	<0.001
29	TBD	H-XXX	H-XXX	TBD	Purity Propane Project	--	-	11.70	11.70	11.70
30	TBD	AU-4	FLR-5	TBD	Train 5 Expansion Project	-	-	0.65	0.65	0.65
31	TBD	F5A	F5A	TBD	Train 5 Expansion Project	-	-	3.16	3.16	3.16
32	TBD	F5B	F5B	TBD	Train 5 Expansion Project	-	-	3.16	3.16	3.16
33	TBD	TEG-2	FLR-5	TBD	Train 5 Expansion Project	-	-	0.20	0.20	0.20
34	TBD	FLR-5	FLR-5	TBD	Train 5 Expansion Project	-		2.02	2.02	2.02
35	TBD	Maintenance	FLR-5	TBD	Train 5 Expansion Project	-	-	< 0.01	< 0.01	< 0.01
36	TBD	Startup	FLR-5	TBD	Train 5 Expansion Project	-	-	0.03	0.03	0.03
37	TBD	Shutdown	FLR-5	TBD	Train 5 Expansion Project	-	-	0.03	0.03	0.03
									Total	**-2.23**

* Estimated start of operation

1. Individual Table 3Fs should be used to summarize the project emission increase and net emission increase for each criteria pollutant.
2. The start of operation date for the modified or new facilities. Attach Table 4F for each project reduction claimed.
3. Emission Point No. as designated in NSR Permit or Emissions Inventory.
4. All records and calculations for these values must be available upon request.
5. Allowable (column A) - Baseline (column B).
6. If portion of the decrease not creditable, enter creditable amount. If all of decrease is creditable or if this line is an increase, enter column C again.
7. Sum all values for this page.

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TABLE 3F
PROJECT CONTEMPORANEOUS CHANGES[1]

Company: Targa Midstream Services LLC	
Permit Application Number: N/A	Criteria Pollutant: VOC

Project Date[2]		Facility at Which Emission Change Occured[3]		Permit No.	Project Name or Activity	A Baseline Period	B Baseline Emissions (tons/year)	Proposed Emissions (tons/year)	Difference (B-A)[5]	Creditable Decrease or Increase[6]
		FIN	EPN							
1	2/1/2009	F-B	F-B	85385	Furnace B Change	2004-2005	2.75	3.61	0.86	0.86
2	4/11/2009	B-09A	B-09A	81524	Temporary Boiler	2007-2008	1.13	0.00	-1.13	-1.13
3	4/11/2009	B-09B	B-09B	81524	Temporary Boiler	2007-2008	1.13	0.00	-1.13	-1.13
4	7/15/2009	GT-1	GT-1	84814	CoGen Permit	2007-2008	0.00	4.98	4.98	4.98
5	7/15/2009	B-09C	B-09C	83115	Temporary Boiler - removed	2007-2008	1.86	0.00	-1.86	-1.86
6	1/20/2011	AU-1	FLR-1NSCAP	106.261	Amine Treater Temporary	2009-2010	-	0.74	0.74	0.74
7	2/9/2011	AU-1	FLR-1NSCAP	106.261	Amine Treater Temporary		0.74	-	-0.74	-0.74
8	3/30/2011	GLY-2	FLR-1NSCAP	91519	T-14 Expansion Project	2006-2007	-	1.66	1.66	1.66
9	3/30/2011	FUG-FRAC	FUG-FRAC	91519	T-14 Expansion Project	2006-2007	-	1.03	1.03	1.03
10	3/30/2011	CT-7	CT-7	91519	T-14 Expansion Project	2006-2007	-	1.53	1.53	1.53
11	3/30/2011	AU-2	FLR-1NSCAP	91519	T-14 Expansion Project (120 gpm)	2006-2007	5.92	3.97	-1.95	-1.95
12	4/18/2011	TEMP-WASH	TEMP-WASH	106.511	Temporary Wash Pump	2009-2010	-	0.05	0.05	0.05
13	10/3/2011	RB2011A	RB2011A	98061	Rental Boiler_2011A	2009-2010	-	0.53	0.53	0.53
14	10/3/2011	RB2011B	RB2011B	98061	Rental Boiler_2011B	2009-2010	-	0.53	0.53	0.53
15	10/28/2011	TEMP-WASH	TEMP-WASH	106.511	Temporary Wash Pump	2009-2010	0.05	-	-0.05	-0.05
16	12/31/2011	RB2011A	RB2011A	98061	Rental Boiler_2011A	2009-2010	0.53	-	-0.53	-0.53
17	12/31/2011	RB2011B	RB2011B	98061	Rental Boiler_2011B	2009-2010	0.53	-	-0.53	-0.53
18	1/24/2012	FUG-C6	FUG-C6	5452	Gasoline Stabilizer	--	-	1.45	1.45	1.45
19	1/24/2012	GS-MSS	GS-MSS	5452	Gasoline Stabilizer	--	-	0.05	0.05	0.05
20	1/24/2012	GS-MSS	FLR-1NSCAP	5452	Gasoline Stabilizer	--	-	0.03	0.03	0.03
21	1/24/2012	BOILERS	BOILERS	multiple	Gasoline Stabilizer	--	-	2.02	2.02	2.02
22	8/31/2012*	multiple	FLR-1NSCAP	95200	RTO Installation	2008-2009	77.99	30.00	-47.99	-47.99
23	8/31/2012*	RTO-1	RTO-1	95200	RTO Installation	--	-	30.00	30.00	30.00
24	8/31/2012*	RTO-2	RTO-2	95200	RTO Installation	--	-	2.89	2.89	2.89
25	5/1/2013*	AU-3	RTO-2	94872	Train 4 Expansion Project	--	-	0.12	0.12	0.12
26	5/1/2013*	H-701A	H-701A	94872	Train 4 Expansion Project	--	-	0.39	0.39	0.39
27	5/1/2013*	H-701B	H-701B	94872	Train 4 Expansion Project	--	-	0.39	0.39	0.39
28	5/1/2013*	FUG-FRAC2	FUG-FRAC2	94872	Train 4 Expansion Project	--	-	4.59	4.59	4.59
29	5/1/2013*	FUG-CT-8	FUG-CT-8	94872	Train 4 Expansion Project	--	-	7.13	7.13	7.13
30	5/1/2013*	TEG-1	RTO-1	94872	Train 4 Expansion Project	--	-	0.08	0.08	0.08
31	5/1/2013*	Maintenance	RTO-1	94872	Train 4 Expansion Project	--	-	0.13	0.13	0.13
32	5/1/2013*	Maintenance	Maintenance	94872	Train 4 Expansion Project	--	-	0.01	0.01	0.01
33	5/1/2013*	Startup	RTO-1	94872	Train 4 Expansion Project	--	-	0.18	0.18	0.18
34	5/1/2013*	Shutdown	RTO-1	94872	Train 4 Expansion Project	--	-	0.31	0.31	0.31
35	5/1/2013*	Shutdown	Shutdown	94872	Train 4 Expansion Project	--	-	0.07	0.07	0.07
36	5/1/2013*	TK-1	TK-1	94872	Train 4 Expansion Project	--	-	<0.01	<0.01	<0.01
37	TBD	H-XXX	H-XXX	TBD	Purity Propane Project	--	-	0.25	0.25	0.25
38	TBD	FUG-FRACX	FUG-FRACX	TBD	Purity Propane Project	--	-	1.03	1.03	1.03

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TABLE 3F
PROJECT CONTEMPORANEOUS CHANGES[1]

Company: Targa Midstream Services LLC	
Permit Application Number: N/A	**Criteria Pollutant: VOC**

Project Date[2]		Facility at Which Emission Change Occured[3]		Permit No.	Project Name or Activity	A Baseline Period	B Baseline Emissions (tons/year)	Proposed Emissions (tons/year)	Difference (B-A)[5]	Creditable Decrease or Increase[6]
		FIN	EPN							
39	TBD	AU-4	FLR-5	TBD	Train 5 Expansion Project	--	-	0.06	0.06	0.06
40	TBD	F5A	F5A	TBD	Train 5 Expansion Project	--	-	0.38	0.38	0.38
41	TBD	F5B	F5B	TBD	Train 5 Expansion Project	--	-	0.38	0.38	0.38
42	TBD	FUG-FRAC5	FUG-FRAC5	TBD	Train 5 Expansion Project	--	-	1.38	1.38	1.38
43	TBD	FUG-CT-9	FUG-CT-9	TBD	Train 5 Expansion Project	--	-	7.13	7.13	7.13
44	TBD	TEG-2	FLR-5	TBD	Train 5 Expansion Project	--	-	0.17	0.17	0.17
45	TBD	FLR-5	FLR-5	TBD	Train 5 Expansion Project	--	-	1.49	1.49	1.49
46	TBD	Maintenance	FLR-5	TBD	Train 5 Expansion Project	--	-	0.63	0.63	0.63
47	TBD	Maintenance	Maintenance	TBD	Train 5 Expansion Project	--	-	0.01	0.01	0.01
48	TBD	Startup	FLR-5	TBD	Train 5 Expansion Project	--	-	0.51	0.51	0.51
49	TBD	Shutdown	FLR-5	TBD	Train 5 Expansion Project	--	-	0.99	0.99	0.99
50	TBD	Shutdown	Shutdown	TBD	Train 5 Expansion Project	--	-	0.07	0.07	0.07
51	TBD	TK-2	TK-2	TBD	Train 5 Expansion Project	--	-	<0.01	<0.01	<0.01
									Total **	**20.32**

* Estimated start of operation

** For total emission calculations, emissions represented as less than 0.01 tpy are conservatively assumed to be 0.01 tpy.

1. Individual Table 3Fs should be used to summarize the project emission increase and net emission increase for each criteria pollutant.
2. The start of operation date for the modified or new facilities. Attach Table 4F for each project reduction claimed.
3. Emission Point No. as designated in NSR Permit or Emissions Inventory.
4. All records and calculations for these values must be available upon request.
5. Allowable (column A) - Baseline (column B).
6. If portion of the decrease not creditable, enter creditable amount. If all of decrease is creditable or if this line is an increase, enter column C again.
7. Sum all values for this page.

This section discusses the approach used in completing the GHG BACT analysis, as well as documenting the emission units for which the GHG BACT analyses were performed.

10.1. BACT DEFINITION

The requirement to conduct a BACT analysis is set forth in the PSD regulations in 40 CFR §52.21(j)(2):

(j) Control Technology Review.

(2) A new major stationary source shall apply best available control technology for each regulated NSR pollutant that it would have the potential to emit in significant amounts.

BACT is defined in the PSD regulations 40 CFR §52.21(b)(12)(emphasis added) in relevant part as:

…an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under 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 a 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.

Although this definition was not changed by the Tailoring Rule, differences in the characteristics of criteria pollutant and GHG emissions from large industrial sources present several GHG-specific considerations under the BACT definition which warrant further discussion. Those underlined terms in the BACT definition are addressed further below.

10.1.1. Emission Limitation

BACT is "an emission limitation," not an emission reduction rate or a specific technology. While BACT is prefaced upon the application of technologies reflecting the maximum reduction rate achievable, the final result of BACT is an emission limit. Typically when quantifiable and measurable[13], this limit would be expressed as an emission rate limit of a pollutant (e.g., lb/MMBtu, ppm, or lb/hr).[14] Furthermore, EPA's guidance on GHG BACT has indicated that GHG BACT limitations should be averaged over long-term timeframes such as 30- or 365-day rolling average.[15]

10.1.2. Each Pollutant

Since BACT applies to "each pollutant subject to regulation under the Act," the BACT evaluation process is typically conducted for each regulated NSR pollutant individually and not for a combination of pollutants.[16] For PSD

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[13] The definition of BACT allows use of a work practice where emissions are not easily measured or enforceable. 40 CFR §52.21(b)(12).

[14] Emission limits can be broadly differentiated as "rate-based" or "mass-based." For a turbine, a rate-based limit would typically be in units of lb/MMBtu (mass emissions per heat input). In contrast, a typical mass-based limit would be in units of lb/hr (mass emissions per time).

[15] *PSD and Title V Permitting Guidance for Greenhouse Gases*. March 2011, page 46.

[16] 40 CFR §52.21(b)(12)

applicability assessments involving GHGs, the regulated NSR pollutant subject to regulation under the Clean Air Act (CAA) is the sum of six greenhouse gases and not a single pollutant.[17] In the final Tailoring Rule preamble, EPA went beyond applying this combined pollutant approach for GHGs to PSD applicability and made the following recommendations that suggest applicants should conduct a single GHG BACT evaluation on a CO_2e basis for emission sources that emit more than one GHG:

> *However, we disagree with the commenter's ultimate conclusion that BACT will be required for each constituent gas rather than for the regulated pollutant, which is defined as the combination of the six well-mixed GHGs. To the contrary, we believe that, in combination with the sum-of-six gases approach described above, the use of the CO_2e metric will enable the implementation of flexible approaches to design and implement mitigation and control strategies that look across all six of the constituent gases comprising the air pollutant (e.g., flexibility to account for the benefits of certain CH_4 control options, even though those options may increase CO_2). Moreover, we believe that the CO_2e metric is the best way to achieve this goal because it allows for tradeoffs among the constituent gases to be evaluated using a common currency.*[18]

For the proposed project, the GHG emissions are driven primarily by CO_2. CO_2 emissions represent more than 99% of the total CO_2e for the project as a whole. As such, the following top-down GHG BACT analysis should and will focus on CO_2.

10.1.3. BACT Applies to the Proposed Source

BACT applies to the type of source proposed by the applicant. BACT does not redefine the source. The applicant defines the source (i.e., its goals, aims and objectives). Although BACT is based on the type of source as proposed by the applicant, the scope of the applicant's ability to define the source is not absolute. A key task for the reviewing agency is to determine which parts of the proposed process are inherent to the applicant's purpose and which parts may be changed without changing that purpose. Targa has provided project discussion in Section 5 of this report to aid the technical reviewers in need and scope of this project and how GHG BACT should be reviewed in light of this detailed information.

10.1.4. Case-By-Case Basis

Unlike many of the CAA programs, the PSD program's BACT evaluation is case-by-case. BACT permit limits are not simply the requirement for a control technology because of its application elsewhere or the direct transference of the lowest emission rate found in other permits for similar sources, applied to the proposed source. EPA has explained how the top-down BACT analysis process works on a case-by-case basis. To assist applicants and regulators with the case-by-case process, in 1990 EPA issued a Draft Manual on New Source Review permitting which included a "top-down" BACT analysis.

> *In brief, the top-down process provides that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent--or "top"--alternative. That alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.*[19]

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[17] 40 CFR § 52.21(b)(49)(i)

[18] 75 FR 31,531, *Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule; Final Rule, June 3, 2010.*

[19] Draft NSR Manual at B-2. "The NSR Manual has been used an a guidance document in conjunction with new source review workshops and training, and as a simple guide for state and federal permitting officials with respect to PSD requirements and policy. Although it is not binding

The five steps in a top-down BACT evaluation can be summarized as follows:

> Step 1. Identify all available control technologies;
> Step 2. Eliminate technically infeasible options;
> Step 3. Rank the technically feasible control technologies by control effectiveness;
> Step 4. Evaluate most effective controls; and
> Step 5. Select BACT.

While this EPA-recommended five-step process can be directly applied to GHGs without any significant modifications, it is important to note that the top-down process is conducted on a unit-by-unit, pollutant-by-pollutant basis and only considers the portions of the facility that are considered "emission units" as defined under the PSD regulations.[20]

10.1.5. Achievable

BACT is to be set at the lowest value that is "achievable." However, there is an important distinction between emission rates achieved at a specific time on a specific unit, and an emission limitation that a unit must be able to meet continuously over its operating life. As discussed by the DC Circuit Court of Appeals:

> *In National Lime Ass'n v. EPA, 627 F.2d 416, 431 n.46 (D.C. Cir. 1980), we said that where a statute requires that a standard be "achievable," it must be achievable" under most adverse circumstances which can reasonably be expected to recur."*[21]

EPA has reached similar conclusions in prior determinations for PSD permits.

> *Agency guidance and our prior decisions recognize a distinction between, on the one hand, measured 'emissions rates,' which are necessarily data obtained from a particular facility at a specific time, and on the other hand, the 'emissions limitation' determined to be BACT and set forth in the permit, which the facility is required to continuously meet throughout the facility's life. Stated simply, if there is uncontrollable fluctuation or variability in the measured emission rate, then the lowest measured emission rate will necessarily be more stringent than the "emissions limitation" that is "achievable" for that pollution control method over the life of the facility. Accordingly, because the "emissions limitation" is applicable for the facility's life, it is wholly appropriate for the permit issuer to consider, as part of the BACT analysis, the extent to which the available data demonstrate whether the emissions rate at issue has been achieved by other facilities over a long term.*[22]

Thus, BACT must be set at the lowest feasible emission rate recognizing that the facility must be in compliance with that limit for the lifetime of the facility on a continuous basis. While viewing individual unit performance can be instructive in evaluating what BACT might be, any actual performance data must be viewed carefully, as rarely will the data be adequate to truly assess the performance that a unit will achieve during its entire operating life.

Agency regulation, the NSR Manual has been looked to be this Board as a statement of the Agency's thinking on certain PSD issues. E.g., *In re RockGen Energy Ctr*., 8 E.A.D. 536, 542 n. 10 (EAB 1999), *In re Knauf Fiber Glass*, *GmbH*, 8 E.A.D. 121, 129 n. 13 (EAB 1999)." *In re Prairie State Generating Company* 13 E.A.D. 1, 13 n 2 (2006)

[20] Pursuant to 40 CFR §52.21(a)(7), emission unit means any part of a stationary source that emits or would have the potential to emit any regulated NSR pollutant.

[21] As quoted in Sierra Club v. U.S. EPA (97-1686).

[22] U.S. EPA Environmental Appeals Board decision, *In re: Newmont Nevada Energy Investment L.L.C.* PSD Appeal No. 05-04, decided December 21, 2005. Environmental Administrative Decisions, Volume 12, Page 442.

To assist in meeting the BACT limit, the source must consider production processes or available methods, systems or techniques, as long as those considerations do not redefine the source.

10.1.6. Production Process

The definition of BACT lists both production processes and control technologies as possible means for reducing emissions.

10.1.7. Available

The term "available" in the definition of BACT is implemented through a feasibility analysis – a determination that the technology being evaluated is demonstrated or available and applicable.

10.1.8. Floor

For criteria pollutants, the least stringent emission rate allowable for BACT is any applicable limit under either NSPS (40 CFR Part 60) or NESHAP (40 CFR Part 61). Since no GHG limits have been incorporated into any existing NSPS or Part 61 NESHAPs, as of the submittal of this application, no floor for a GHG BACT analysis is available for consideration.

10.2. GHG BACT ASSESSMENT METHODOLOGY

GHG BACT for the proposed project has been evaluated via a "top-down" approach which includes the steps outlined in the following subsections.

EPA's March 2011 GHG Permitting Guidance generally directed that a BACT review for GHGs should be done in the same manner as it is done for any other regulated pollutant.[23] It should be noted that the scope of a BACT review was clarified in two ways with respect to GHGs:

- EPA stressed that applicants should clearly define the scope of the project being reviewed.[24] Targa has provided this information in Section 5 of this application.
- EPA clarified that the scope of the BACT should focus on the project's largest contributors to CO_2e and may subject less significant contributors for CO_2e to less stringent BACT review.[25] Because the project's GHG emissions are dominated by the hot oil heaters, this BACT analysis focuses mainly on these predominant sources of CO_2e from the project.

10.2.1. Step 1 - Identify All Available Control Technologies

Available control technologies for CO_2e with the practical potential for application to the emission unit are identified. The application of demonstrated control technologies in other similar source categories to the emission unit in question can also be considered. While identified technologies may be eliminated in subsequent steps in the analysis based on technical and economic infeasibility or environmental, energy, economic or other impacts, control technologies with potential application to the emission unit under review are identified in this step.

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[23] *PSD and Title V Permitting Guidance for Greenhouse Gases.* March 2011, page 17.

[24] *PSD and Title V Permitting Guidance for Greenhouse Gases.* March 2011, pages 22-23.

[25] *PSD and Title V Permitting Guidance for Greenhouse Gases.* March 2011, page 31.

Under Step 1 of a criteria pollutant BACT analysis, the following resources are typically consulted when identifying potential technologies:

1. EPA's Reasonably Available Control Technology (RACT)/Best Available Control Technology (BACT)/Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) database;
2. Determinations of BACT by regulatory agencies for other similar sources or air permits and permit files from federal or state agencies;
3. Engineering experience with similar control applications;
4. Information provided by air pollution control equipment vendors with significant market share in the industry; and/or
5. Review of literature from industrial technical or trade organizations.

However, since GHG BACT is a new requirement, the RBLC database search did not result in any records for GHGs. Primarily, Targa will rely on items (2) through (5) and preliminary information from the EPA BACT GHG Workgroup for data to establish BACT.

EPA's "top-down" BACT analysis procedure also recommends the consideration of inherently lower emitting processes as available control options under Step 1.[26] For GHG BACT analyses, low-carbon intensity fuel selection is the primary control option that can be considered a lower emitting process. Targa proposes the use of pipeline quality natural gas only for all combustion equipment associated with the proposed project. Table C-1 of 40 CFR Part 98 shows CO_2 emissions per unit heat input (MMBtu) for a wide variety of industrial fuel types. Only biogas (captured methane) and coke oven gas result in lower CO_2 emissions per unit heat input than natural gas.

Additionally, EPA's GHG BACT guidance suggests that carbon capture and sequestration (CCS) be evaluated as an available control for substantial, large projects such as steel mills, refineries, and cement plants where CO_2e emissions levels are in the order of 1,000,000 tpy, or for industrial facilities with high-purity CO_2 streams.[27] However, EPA explained that "[t]his does not necessarily mean CCS should be selected as BACT for such sources." The proposed Train 5 Project emissions are approximately 165,672 tpy CO_2e (including emissions from MSS activities). Only the amine treater (used to remove CO_2 from the inlet gas), which exhausts through the flare, results in a concentrated CO_2 stream with sulfur compound impurities. All other emission sources result in low purity CO_2 streams. Nonetheless, CCS is evaluated as a control option for the proposed project.

10.2.2. Step 2 – Eliminate Technically Infeasible Options

After the available control technologies have been identified, each technology is evaluated with respect to its technical feasibility in controlling GHG emissions from the source in question. The first question in determining whether or not a technology is feasible is whether or not it is demonstrated. If so, it is feasible. Whether or not a control technology is demonstrated is considered to be a relatively straightforward determination.

> Demonstrated "means that it has been installed and operated successfully elsewhere on a similar facility." *Prairie State*, slip op. at 45. "This step should be straightforward for control technologies that are demonstrated--if the control technology has been installed and operated successfully on the type of source under review, it is demonstrated and it is technically feasible."[28]

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[26] *PSD and Title V Permitting Guidance for Greenhouse Gases.* March 2011, page 24.

[27] *PSD and Title V Permitting Guidance for Greenhouse Gases.* March 2011, pages 32-33.

[28] NSR Workshop Manual (Draft), Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting, page B.17.

An undemonstrated technology is only technically feasible if it is "available" and "applicable." A control technology or process is only considered available if it has reached the licensing and commercial sales phase of development and is "commercially available".[29] Control technologies in the R&D and pilot scale phases are not considered available. Based on EPA guidance, an available control technology is presumed to be applicable if it has been permitted or actually implemented by a similar source. Decisions about technical feasibility of a control option consider the physical or chemical properties of the emissions stream in comparison to emissions streams from similar sources successfully implementing the control alternative. The NSR Manual explains the concept of applicability as follows: "An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration."[30] Applicability of a technology is determined by technical judgment and consideration of the use of the technology on similar sources as described in the NSR Manual.

10.2.3. Step 3 – Rank Remaining Control Technologies by Control Effectiveness

All remaining technically feasible control options are ranked based on their overall control effectiveness for GHG. For GHGs, this ranking may be based on energy efficiency and/or emission rate.

10.2.4. Step 4 – Evaluate Most Effective Controls and Document Results

After identifying and ranking available and technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the best control option. If adverse collateral impacts do not disqualify the top-ranked option from consideration it is selected as the basis for the BACT limit. Alternatively, in the judgment of the permitting agency, if unreasonable adverse economic, environmental, or energy impacts are associated with the top control option, the next most stringent option is evaluated. This process continues until a control technology is identified. EPA recognized in its BACT guidance for GHGs that "[e]ven if not eliminated at Step 2 of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in Step 4 of the BACT analysis, even in some cases where underground storage of the captured CO_2 near the power plant is feasible."[31]

The energy, environment, and economic impacts analysis under Step 4 of a GHG BACT assessment presents a unique challenge with respect to the evaluation of CO_2 and CH_4 emissions. The technologies that are most frequently used to control emissions of CH_4 in hydrocarbon-rich streams (e.g., flares and thermal oxidizers) actually convert CH_4 emissions to CO_2 emissions. Consequently, the reduction of one GHG (i.e., CH_4) results in a proportional increase in emissions of another GHG (i.e., CO_2). However, since the GWP of CH_4 is 21 times higher than CO_2, conversion of CH_4 emissions to CO_2 results in a net reduction of CO_2e emissions.

Permitting authorities have historically considered the effects of multiple pollutants in the application of BACT as part of the PSD review process, including the environmental impacts of collateral emissions resulting from the implementation of emission control technologies. To clarify the permitting agency's expectations with respect to the BACT evaluation process, states have sometimes prioritized the reduction of one pollutant above another. For example, technologies historically used to control NO_X emissions frequently caused increases in CO emissions. Accordingly, several states prioritized the reduction of NO_X emissions above the reduction of CO emissions, approving low NO_X control strategies as BACT that result in higher CO emissions relative to the uncontrolled emissions scenario.

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[29] NSR Workshop Manual (Draft), Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting, page B.18.

[30] NSR Workshop Manual (Draft), Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting, page B.18.

[31] *PSD and Title V Permitting Guidance for Greenhouse Gases.* March 2011, pages 42-43.

10.2.5. Step 5 - Select BACT

In the final step, the BACT emission limit is determined for each emission unit under review based on evaluations from the previous step.

Although the first four steps of the top-down BACT process involve technical and economic evaluations of potential control options (i.e., defining the appropriate technology), the selection of BACT in the fifth step involves an evaluation of emission rates achievable with the selected control technology. BACT is an emission limit unless technological or economic limitations of the measurement methodology would make the imposition of an emissions standard infeasible, in which case a work practice or operating standard can be imposed.

Establishing an appropriate averaging period for the BACT limit is a key consideration under Step 5 of the BACT process. Localized GHG emissions are not known to cause adverse public health or environmental impacts. Rather, EPA has determined that GHG emissions are anticipated to contribute to long-term environmental consequences on a global scale. Accordingly, EPA's Climate Change Workgroup has characterized the category of regulated GHGs as a "global pollutant." Given the global nature of impacts from GHG emissions, NAAQS are not established for GHGs in the Tailoring Rule and a dispersion modeling analysis for GHG emissions is not a required element of a PSD permit application for GHGs. Since localized short-term health and environmental effects from GHG emissions are not recognized, Targa proposes only an annual average GHG BACT limit.

10.3. GHG BACT REQUIREMENT

The GHG BACT requirement applies to each new emission unit from which there are emissions increases of GHG pollutants subject to PSD review. The estimated emissions increase of GHGs from the proposed project will be greater than 75,000 tpy on a CO_2e basis primarily due to the combustion of natural gas fuel in the hot oil heaters.

Potential emissions of GHGs from the proposed project will result from the following emission units:

- Amine Unit (FIN AU-4, EPN FLR-5)
- TEG Dehydration Unit (FIN TEG-2, EPN FLR-5)
- Flare (EPN FLR-5)
- Hot Oil Heaters (EPNs F5A and F5B)
- Fugitives (EPN FUG-FRAC5)

Table 1-1 provides a summary of the estimated maximum annual potential to emit GHG emission rates for the proposed project. GHG emissions for each emission unit were estimated based on proposed equipment specifications as provided by the manufacturer and the default emission factors in the EPA's Mandatory Greenhouse Reporting Rule (40 CFR 98, Subpart C and Subpart W).

Targa is also proposing to construct several small atmospheric storage tanks and a cooling tower (EPN FUG-CT-9). However, based on the low vapor pressure, low throughput, and contents of the tanks and the composition of the recirculation water in the cooling tower, GHG emissions have been determined to be negligible and emission estimates for operation of these units are not included in this GHG PSD permit application.

This BACT analysis focuses mainly on the predominant sources of CO_2e from the project. GHG emissions from small emission sources such as MSS activities vented directly to the atmosphere are not included in the BACT analysis.

The following guidance documents were utilized as resources in completing the GHG BACT evaluation for the proposed project:

- *PSD and Title V Permitting Guidance for Greenhouse Gases* (hereafter referred to as General GHG Permitting Guidance)[32]
- *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Industrial Boilers* (hereafter referred to as GHG BACT Guidance for Boilers)[33]
- *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry* (hereafter referred to as GHG BACT Guidance for Refineries)[34]

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[32] U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: March 2011). http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf

[33] 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

[34] 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/refineries.pdf

11. GHG BACT EVALUATION FOR PROPOSED EMISSION SOURCES

The following is an analysis of BACT for the control of GHG emissions from the proposed Train 5 Project following the EPA's five-step "top-down" BACT process. The table at the end of this section summarizes each step of the BACT analysis for the emission units included in this review. Targa is proposing the use of good combustion practices for all combustion sources at the proposed facility. A table detailing good combustion practices is also included at the end of this section.

Table 11-1 provides a summary of the proposed BACT limits for the project.

Table 11-1. Potential BACT Limits for Proposed Project

EPN	Description	Proposed BACT Limit (CO_2e tpy)
FLR-5	Pilot Gas and Supplemental Fuel Combustion, Amine Unit, TEG Dehydrator, and MSS activities	17,615
F5A	Hot Oil Heater	74,026
F5B	Hot Oil Heater	74,026
FUG-FRAC5	Fugitive Emissions	2.33

11.1. OVERALL PROJECT ENERGY EFFICIENCY CONSIDERATIONS

While the five-step BACT analysis is the EPA's preferred methodology with respect to selection of control technologies for pollutants, EPA has also indicated that an overarching evaluation of energy efficiency should take place as increases in energy efficiency will inherently reduce the total amount of GHG emissions produced by the source.[35] As such, overall energy efficiency was a basic design criterion in the selection of technologies and processing alternatives to be installed for Train 5 at the Mont Belvieu Plant.

The new 100,000 barrel per day Fractionation Train 5 at the Mont Belvieu Plant will be designed and constructed using all new, energy efficient equipment. The plant is designed for the separation of mixed NGLs into specification NGL products using minimal fuel and power. This is accomplished using a state of the art recovery process incorporating multiple exchangers for maximum heat recovery/integration and high efficiency mass transfer equipment.

The facility is completely electric driven from an existing high voltage transmission line located adjacent to the property. There will be five (5) total electric driven compressors used in this process: two (2) for ethane product compression/liquefaction, one (1) for the Butane Splitter overheads compression/condensing, and two (2) for propane refrigerant compression. The Butane Splitter overheads compression scheme is arranged in such a way that the total heating and cooling duty of the column is reduced by approximately 120 MMBtu/hr. The hot compressed vapor leaving the compressor is used as the heat source for the column's reboiler. The benefit from this heat integration is two-fold. The required heating duty for the reboiler that would have otherwise been provided by the heat medium system, approximately 60 MMBtu/hr, is instead provided by the hot, compressed vapor. The total

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[35] *PSD and Title V permitting Guidance for Greenhouse Gases, March 2011, pages 21-22.*

required cooling duty for the overhead condenser has also been reduced by the same 60 MMBtu/hr since that portion of cooling will be provided by the bottoms of the tower. This cooling also reduces the total amount of cooling water needed in order to condense the iso-Butane product.

All pumps containing VOCs and the hot oil pumps containing heavy oil will have tandem seals equipped with detection or alarm points to eliminate seal leakage and alert personnel when the first seal begins to leak.

The plant will utilize an activated amine as the treating fluid because of its affinity for CO_2. This amine is more expensive but requires the lowest circulation rates and lowest heat duties (lowest fuel) to treat the ethane than other amine solutions.

The glycol dehydration unit has been sized for minimal circulation and minimal heat duty. It will be used to dehydrate ethane product for compression, liquefaction and storage as well as remove water from vapor inside the Deethanizer to prevent hydrate formation in the tower. The vents from the amine unit will be routed to a smokeless flare stack to assure complete destruction of VOCs and hazardous components. The glycol vent will also be routed to a smokeless flare stack.

The plant will run on compressed air for instrument control. No process gas will be utilized or vented for these applications. In addition, all pressure safety valves (PSVs) relieving heavier than air components will be routed in a closed system to a smokeless flare stack for effective combustion, as will all compressor blowdown vents.

The facility will have a sump system for collection of incidental condensate/oil from process scrubbers and dumps. All major skids/equipment containing ground contaminating liquids will have curbed concrete pads underneath to facilitate maintenance and to collect any drips/spills underneath. Compressor packages will have drip rails installed on skids to contain and collect oil drips/spills.

11.2. HOT OIL HEATERS

GHG emissions from the proposed process heaters include CO_2, CH_4 and N_2O and result from the combustion of natural gas. The heaters include two hot oil heaters (EPNs F5A and F5B). The following section presents BACT evaluations for GHG emissions from the proposed hot oil heaters.

11.2.1. Step 1 – Identify All Available Control Technologies

The available GHG emission control strategies for the hot oil heaters that were analyzed as part of this BACT analysis include:

- Carbon Capture and Sequestration;
- Fuel Selection;
- Good Combustion Practices, Operating, and Maintenance Practices;
- Oxygen Trim Controls;
- Heat Recovery; and
- Efficient Heater Design.

11.2.1.1. Carbon Capture and Sequestration

As previously discussed, the contribution of CO_2e emissions from the heaters is a fraction of the scale for sources where CCS might ultimately be feasible. Although we believe that it is obvious that CCS is not BACT in this case, as directly supported in EPA's GHG BACT Guidance, a detailed rationale is provided to support this conclusion.

For the hot oil heaters, CCS would involve post combustion capture of the CO_2 from the heaters and sequestration of the CO_2 in some fashion. In general, carbon capture could be accomplished with low pressure scrubbing of CO_2 from the exhaust stream with solvents (e.g., amines and ammonia), solid sorbents, or membranes. However, only solvents have been used to-date on a commercial (yet slip stream) scale and solid sorbents and membranes are only in the research and development phase. A number of post-combustion carbon capture projects have taken place on slip streams at coal-fired power plants. Although these projects have demonstrated the technical feasibility of small-scale CO_2 capture on a slipstream of a power plant's emissions using various solvent based scrubbing processes, until these post-combustion technologies are installed fully on a power plant, they are not considered "available" in terms of BACT.

Larger scale CCS demonstration projects have been proposed through the DOE Clean Coal Power Initiative (CCPI); however, none of these facilities are operating, and, in fact, they have not yet been fully designed or constructed.[36] Additionally, these demonstration projects are for post-combustion capture on a pulverized coal (PC) plant using a slip stream versus the full exhaust stream. Also, the exhaust from a PC plant would have a significantly higher concentration of CO_2 in the slipstream as compared to a more dilute stream from the combustion of natural gas.[37] In addition, the compression of the CO_2 would require additional power demand, resulting in additional fuel consumption (and CO_2 emissions).[38]

11.2.1.2. Fuel Selection

Natural gas has the lowest carbon intensity of any available fuel for the hot oil heaters. The proposed hot oil heaters will be fired with only natural gas fuel.

11.2.1.3. Good Combustion, Operating, and Maintenance Practices

Good combustion and operating practices are a potential control option by improving the fuel efficiency of the hot oil heaters. Good combustion practices also include proper maintenance and tune-up of the hot oil heaters at least annually per the manufacturer's specifications.

11.2.1.4. Oxygen Trim Controls

Combustion units operated with too much excess air may lead to inefficient combustion, and additional energy will be needed to heat the excess air. Oxygen monitors and intake air flow monitors can be used to optimize the fuel/air mixture. [39]

11.2.1.5. Heat Integration

The plant is equipped with multiple process-to-process cross heat exchangers for maximum heat integration and high efficiency mass transfer equipment to recover heat and reduce the overall energy use at the plant. The process-to-process cross heat exchangers minimize the size of the hot oil heaters to meet the process demands of the train. In addition, the Butane Splitter overheads compression scheme is arranged in such a way that the total heating and cooling duty is reduced by approximately 120 MMBtu/hr.

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[36] Report of the Interagency Task Force on Carbon Capture & Storage, August 2010, p. 32.

[37] Report of the Interagency Task Force on Carbon Capture & Storage, August 2010, p. A-7.

[38] Report of the Interagency Task Force on Carbon Capture & Storage, August 2010, http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf, p. 29

[39] *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry*, U.S. EPA, October 2010, Section 3.

11.2.1.6. Efficient Heater Design

Efficient heater design and proper air-to-fuel ratio improve mixing of fuel and create more efficient heat transfer. Since Targa is proposing to install new heaters, these heaters will be designed to optimize combustion efficiency. Additionally, as discussed in Section 11.1, the amine treater and TEG dehydrator have been designed to minimize heat duty and require less fuel to treat inlet NGL.

11.2.2. Step 2 – Eliminate Technically Infeasible Options

As discussed below, CCS is deemed technically infeasible for control of GHG emissions from the process heaters. All other control options are technically feasible.

11.2.2.1. Carbon Capture and Sequestration

The feasibility of CCS is highly dependent on a continuous CO_2-laden exhaust stream, and CCS has not been tested or demonstrated for such small combustion sources. Given the limited deployment of only slipstream/demonstration applications of CCS and the quantity and quality of the CO_2 emissions stream, CCS is not commercially available as BACT for the process heaters and is therefore infeasible. This is supported by EPA's assertion that CCS is considered "available" for projects that emit CO_2 in "large" amounts.[40] This project and these emission units, by comparison, emit CO_2 in small quantities. Therefore, CCS is not considered a technically, economically, or commercially viable control option for the proposed process heaters. CCS is not considered as a control option for further analysis.

11.2.3. Step 3 – Rank Remaining Control Technologies by Control Effectiveness

With elimination of CCS as a control option, the following remain as technically feasible control options for minimizing GHG emissions from the hot oil heaters:

- low carbon fuel selection;
- implementation of good combustion, operating, and maintenance practices;
- installation of oxygen trim controls;
- heat recovery; and
- efficient heater design.

Since Targa proposes to implement all of these control options, ranking these control options is not necessary.

11.2.4. Step 4 – Evaluate Most Effective of Control Options

No adverse energy, environmental, or economic impacts are associated with the above-mentioned technically feasible control options.

11.2.5. Step 5 – Select BACT for the Process Heaters

Targa proposes the following design elements and work practices as BACT for the hot oil heaters:

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[40] PSD and Title V permitting Guidance for Greenhouse Gases. March 2011, page 32. "For the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology[86] that is "available"[87] for facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing). The proposed project is not any of the cases EPA suggests above.

- use of natural gas as fuel;
- implementation of good combustion, operating, and maintenance practices;
- oxygen trim control
- heat recovery; and
- efficient heater design.

Targa proposes the CO_2e emission limits for the heaters:

- Hot Oil Heater (EPN F5A): 74,026 short tons of CO2e per year
- Hot Oil Heater (EPN F5B): 74,026 short tons of CO2e per year

These proposed emission limits are based on a 12-month rolling average basis and include CO_2, CH_4, and N_2O emissions, with CO_2 emissions being more than 99% of the total emissions.

Compliance with these emission limits will be demonstrated by monitoring fuel consumption and performing calculations consistent with the calculations included in Section 7 of this application. These calculations will be performed on a monthly basis to ensure that the 12-month rolling average short tons of CO_2e per year emission rates do not exceed these limits.

11.3. AMINE UNIT AND TEG DEHYDRATOR / FLARE

The amine unit in Train 5 of the Mont Belvieu Plant will be used to absorb CO_2 from a fractionated ethane gas stream to produce a treated gas stream with lower CO_2 content. The TEG dehydration unit will be used to remove water or water vapor present in the ethane gas stream. Stripped amine acid gases and dehydrator waste gases will be routed to a flare. GHG emissions from the flare result from routing removed CO_2 from the amine unit to the flare and the combustion of process waste gases from the amine unit and the dehydrator unit. In addition, GHG emissions are produced from the combustion of vent streams routed to the flare during MSS events and the pilot fuel. Supplemental fuel will be mixed with the amine and dehydrator waste streams to bring the heating value of combusted gas up to 300 Btu/scf as required by 40 CFR § 60.18. CO_2 emissions from the flare are based on the estimated flared carbon-containing gases derived from heat and material balance data. Minor CH_4 emissions from the flare are produced due to incomplete combustion of CH_4. Any organic compound emissions present in the vent gas routed to the flare will be converted to CO_2 in the combustion zone.

11.3.1. Step 1 – Identify All Available Control Technologies

The available GHG emission control options for the process emissions sent to the flare include:

- Carbon Capture and Sequestration

The available GHG emission control strategies for the flare combustion emissions include:

- Carbon Capture and Sequestration
- Fuel Selection;
- Flare Gas Recovery;
- Good Combustion, Operating, Maintenance Practices; and
- Good Flare Design; and
- Limited vent gas releases to flare.

11.3.1.1. Carbon Capture and Sequestration

Targa conducted research and analysis to determine the technical feasibility of CO_2 capture and transfer for emissions to the flare. Since most of the CO_2 emissions being sent to the flare from the proposed project are generated from the amine unit, Targa conducted studies to evaluate potential options to capture and transfer the CO_2 to an off-site facility for injection for these emissions.

Based on the results of these studies, capture and transfer of CO_2 from the amine treatment unit is technically feasible. A study was performed to evaluate the potential options for capture and transfer of CO_2 from the Mont Belvieu Plant (located in Chambers County, TX) to nearby CO_2 injection wells. The transfer of the CO_2 stream will require further treatment to remove contaminants and compression for transfer via a new pipeline.

Since capture and transfer of CO_2 for off-site transfer is technically feasible for the proposed project, this option is further evaluated for energy, environmental, and economic impacts.

11.3.1.2. Fuel Selection

The fuel for firing the proposed flare will be limited to natural gas fuel. Natural gas has the lowest carbon intensity of any available fuel for the Flare.

11.3.1.3. Flare Gas Recovery

Flaring can be reduced by installation of commercially available recovery systems, including recovery compressors and collection and storage tanks. The recovered gas is then utilized by introducing it into the fuel system as applicable.

11.3.1.4. Good Combustion, Operating, and Maintenance Practices

Good combustion and operating practices are a potential control option for improving the combustion efficiency of the flare. Good combustion practices include proper operation, maintenance, and tune-up of the flare at least annually per the manufacturer's specifications.

11.3.1.5. Good Flare Design

Good flare design can be employed to destroy large fractions of the flare gas. Much work has been done by flare and flare tip manufacturers to assure high reliability and destruction efficiencies. Good flare design includes pilot flame monitoring, flow measurement, and monitoring/control of waste gas heating value.

11.3.1.6. Limited Vent Gas Releases to Flare

Minimizing the number and duration of MSS activities and therefore limiting vent gases routed to the flare will help reduce emissions from MSS activities.

11.3.2. Step 2 – Eliminate Technically Infeasible Options

The technical infeasibility of CCS to control flare combustion emissions and flare gas recovery is discussed below. All other control technologies listed in Step 1 are considered technically feasible, including CCS to control process emissions sent to the flare.

11.3.2.1. Carbon Capture and Sequestration

With no ability to collect exhaust gas from a flare other than using an enclosure, post combustion capture is not an available control option; thus, CCS is not considered a technically feasible option to control flare combustion emissions. Therefore, it has been eliminated from further consideration in the remaining steps of the analysis.

CCS to control process emissions remains a technically feasible option.

11.3.2.2. Flare Gas Recovery

Flare gas recovery is deemed technically infeasible for control of GHG emissions from the flare. Specifically, the process gas sent to the flare is rich in CO_2 and cannot be used as fuel gas for the facility. The heat input of the process gas is so low, supplemental fuel will be mixed with the amine and dehydrator waste streams to bring the heating value of combusted gas up to 300 Btu/scf as required by 40 CFR § 60.18.

The flare is also used for control of emissions from emergency situations and MSS activities. Due to the infrequent MSS activities and the amount of gas sent to the flare, it is technically infeasible to re-route the flare gas to a process fuel system and hence, the gas will be combusted by the flare for control. Therefore, flare gas recovery is not feasible for the control of MSS activities. For this project, flare gas recovery is technically infeasible and has been eliminated from further consideration in the remaining steps of the analysis.

11.3.3. Step 3 – Rank Remaining Control Technologies by Control Effectiveness

With elimination of CCS to control flare combustion emissions and flare gas recovery to control process emissions to the flare as technically infeasible control options, the following control options remain as technically feasible control options for minimizing process GHG emissions sent to the flare:

- Carbon capture and sequestration
- Fuel selection
- Good combustion, operating, and maintenance practices
- Good flare design
- Limited vent gas releases to flare

CCS (i.e., sequestration or transfer of CO_2) is the most effective control option for the control of the CO_2 stream from the amine unit to the flare, since it provides approximately 90% CO_2 control of the amine acid gas stream, based on literature review.

Good flare design and operation, low carbon fuel selection, the implementation of good combustion and maintenance practices, and limiting MSS vent gas releases are technically feasible control options for minimizing GHG emissions from the flare.

11.3.4. Step 4 – Evaluate Most Effective Control Options

The only technically feasible technology listed in Step 3 that may have additional energy, environmental, and economic impacts is capture and transfer of the amine CO_2 waste stream.

While the amine acid gas stream routed to the flare is relatively high in CO_2 content, additional processing of the exhaust gas will be required to implement CCS. These include separation (removal of other pollutants from the combustion gases), capture, and compression of CO_2, transfer of the CO_2 stream and sequestration of the CO_2 stream. These processes require additional equipment to reduce the exhaust temperature, compress the gas, and transport the gas via pipelines. These units would require additional electricity and generate additional air emissions, of both criteria pollutants and GHG pollutants. This would result in negative environmental and energy impacts.

As part of the CO_2 transfer feasibility analysis, Targa reviewed currently active CO_2 injection wells identified on the Texas Railroad Commission (RRC) website in and around Chambers County (District No. 3).[41] This website provides the details of registered wells and permitted fluids for injection. Most of the wells are permitted to inject saltwater,

[41] Injection and Disposal Query available at Texas RRC website at: http://webapps2.rrc.state.tx.us/EWA/uicQueryAction.doc

CO_2, or natural gas. Targa refined the search to limit to wells that are permitted for and reported injection of CO_2. Based on the aerial distance from the Mont Belvieu Plant, the nearest CO_2 injection well is located at 24.7 miles. A map of the location of the Mont Belvieu Plant and the nearest well is included in Appendix A of this permit application.

The cost of pipeline installation and operation are obtained from the National Energy Technology Laboratory (NETL)'s Document Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs DOE/NETL-2010/1447. Per this document, the pipeline costs include pipeline installation costs, other related capital costs, and operation and maintenance (O&M) costs. A copy of this document is included in Appendix B of this permit application to provide additional details and assumptions in this study.

Using the cost estimation methods from the NETL document, the cost of capture, compression, and transfer of CO_2 via a pipeline was estimated to be approximately $244 per ton of CO_2 removed from the amine unit and TEG dehydration unit. A detailed cost analysis is included in Appendix C of this permit application. The cost estimation does not include additional capital costs incurred to install compression equipment and other process equipment such as cryogenic units.

Therefore, based on the pipeline transfer cost, although technically feasible, off-site transfer is not regarded as a viable or economically feasible CO_2 control option.

11.3.5. Step 5 – Select BACT for the Flare

Targa proposes the following design elements and work practices as BACT for the Flare:

- Fuel selection
- Good combustion, operating, and maintenance practices
- Good flare design
- Limited vent gas releases to flare

The flare will meet the requirements of 40 CFR §60.18, and will be properly instrumented and controlled. Emission sources whose MSS emissions are routed to the flare will be operated in a manner to minimize the frequency and duration of such MSS activities and therefore, the amount of MSS vent gas released to the flare.

Targa proposes a numerical BACT limit for total GHG emissions emitted from the flare to 17,589 short tons of CO_2e per year (based on a 12-month rolling average). This emissions limit includes emissions from the amine treater and the TEG dehydrator, supplemental and pilot fuel combustion, and MSS activities.

Compliance with these emission limits and throughput limits will be demonstrated by monitoring inlet gas throughput rate and performing calculations consistent with those in Section 7 of this application. These calculations will be performed on a monthly basis to ensure that the 12-month rolling average throughput and short tons of CO_2e per year emission rates do not exceed these limits.

11.4. FUGITIVE COMPONENTS

The following sections present a BACT evaluation of fugitive CO_2 and CH_4 emissions. It is anticipated that the fugitive emission controls presented in this analysis will provide similar levels of emission reduction for both CO_2 and CH_4. Fugitive components included in the proposed Train 5 Project include traditional components such as valves and flanges.

11.4.1. Step 1 - Identify All Available Control Technologies

In determining whether a technology is available for controlling GHG emissions from fugitive components, permits and permit applications and EPA's RBLC were consulted. Based on these resources, the following available control technologies were identified and are discussed below:

- Installing leakless technology components to eliminate fugitive emission sources;
- Installing air-driven pneumatic controllers;
- Implementing various LDAR programs in accordance with applicable state and federal air regulations;
- Implementing an alternative monitoring program using a remote sensing technology such as infrared camera monitoring;
- Implementing an audio/visual/olfactory (AVO) monitoring program for odorous compounds; and
- Designing and constructing facilities with high quality components and materials of construction compatible with the process.

11.4.1.1. Leakless Technology Components

Leakless technology valves are available and currently in use, primarily where highly toxic or otherwise hazardous materials are used. These technologies are generally considered cost prohibitive except for specialized service. Some leakless technologies, such as bellows valves, if they fail, cannot be repaired without a unit shutdown which often generates additional emissions.

11.4.1.2. Air-Driven Pneumatic Controllers

Air-driven pneumatic controllers utilize compressed air and therefore do not emit any GHG emissions.

11.4.1.3. LDAR Programs

LDAR programs have traditionally been developed for the control of VOC emissions. BACT determinations related to control of VOC emissions rely on technical feasibility, economic reasonableness, reduction of potential environmental impacts, and regulatory requirements for these instrumented programs. Monitoring direct emissions of CO_2 is not feasible with the normally used instrumentation for fugitive emissions monitoring. However, instrumented monitoring is technically feasible for components in CH_4 service.

11.4.1.4. Alternative Monitoring Program

Alternate monitoring programs such as remote sensing technologies have been proven effective in leak detection and repair. The use of sensitive infrared camera technology has become widely accepted as a cost effective means for identifying leaks of hydrocarbons.

11.4.1.5. AVO Monitoring Program

Leaking fugitive components can be identified through AVO methods. The fuel gases and process fluids in the Train 5 piping components are expected to have discernable odor, making them detectable by olfactory means. A large leak can be detected by sound (audio) and sight. The visual detection can be a direct viewing of leaking gases, or a secondary indicator such as condensation around a leaking source due to cooling of the expanding gas as it leaves the leak interface. AVO programs are common and in place in industry.

11.4.1.6. High Quality Components

A key element in the control of fugitive emissions is the use of high quality equipment that is designed for the specific service in which it is employed. For example, a valve that has been manufactured under high quality conditions can be expected to have lower runout on the valve stem, and the valve stem is typically polished to a smoother surface. Both of these factors greatly reduce the likelihood of leaking.

11.4.2. Step 2 - Eliminate Technically Infeasible Options

Recognizing that leakless technologies have not been universally adopted as LAER or BACT, even for toxic or extremely hazardous services, it is reasonable to state that these technologies are impractical for control of GHG emissions whose impacts have not been quantified. Any further consideration of available leakless technologies for GHG controls is unwarranted.

All other control options are considered technically feasible.

11.4.3. Step 3 – Rank Remaining Control Technologies by Control Effectiveness

11.4.3.1. Air-Driven Pneumatic Controllers

Installing air-driven pneumatic controllers will result in no GHG emissions to the atmosphere.

11.4.3.2. LDAR Programs

Instrumented monitoring is effective for identifying leaking CH_4, but may be wholly ineffective for finding leaks of CO_2. With CH_4 having a global warming potential greater than CO_2, instrumented monitoring of the fuel and feed systems for CH_4 would be an effective method for control of GHG emissions. Quarterly instrumented monitoring with a leak definition of 500 ppmv (2,000 ppmv for pumps and compressors), accompanied by intense directed maintenance, is generally assigned a control effectiveness of 97% (85% for pumps and compressors). [42]

11.4.3.3. Alternative Monitoring Program

Remote sensing using infrared imaging has proven effective for identification of leaks including CO_2. The process has been the subject of EPA rulemaking as an alternative monitoring method to the EPA's Method 21. Effectiveness is likely comparable to EPA Method 21 when cost is included in the consideration.

11.4.3.4. AVO Monitoring Program

Audio/Visual/Olfactory means of identifying leaks owes its effectiveness to the frequency of observation opportunities. Those opportunities arise as operating technicians make rounds, inspecting equipment during those routine tours of the operating areas. This method cannot generally identify leaks at a low leak rate as instrumented reading can identify; however, low leak rates have lower potential impacts than do larger leaks. This method, due to frequency of observation is effective for identification of larger leaks.

11.4.3.5. High Quality Components

Use of high quality components is effective in preventing emissions of GHGs, relative to use of lower quality components.

11.4.4. Step 4 – Evaluate Most Effective Control Options

No adverse energy, environmental, or economic impacts are associated with the above-mentioned technically feasible control options.

11.4.5. Step 5 – Select BACT for Fugitive Emissions

Targa proposes to implement the most effective remaining control options. The plant will run on compressed air for instrument control. No process gas will be utilized or vented for these applications. Instrumented monitoring

[42] TCEQ published BACT guidelines for fugitive emissions in the document *Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000.*

implemented through the 28 VHP LDAR program, with control effectiveness of 97% for most equipment, is considered top-level BACT. Additionally, Targa will monitor flanges using quarterly OVA monitoring at the same leak definition for valves, resulting in the same control efficiency applied to flanges as is applied to valves.

In addition, Targa will utilize an AVO program to monitor for leaks in between instrumented checks. The proposed project will also utilize high-quality components and materials of construction, including gasketing, that are compatible with the service in which they are employed.

Since Targa is implementing the most effective control options available, additional analysis is not necessary.

Targa is not proposing a numerical BACT limit on GHG emissions from fugitive components since fugitive emissions are estimates only.

Identify Emission Source		List Available Control Technologies			Evaluate Efficiency	Evaluate Cost Effectiveness	Selected as BACT?
Emission Source	**PSD Pollutant**	**Control Technology**	**Description**	**Feasible/Infeasible**	**Typical Control Efficiency**	**Cost Effectiveness**	
Facility-Wide	GHGs	Carbon Capture and Sequestration (CCS)	CCS includes the separation (removal of PM and other pollutants from the combustion gases), capture, and compression of CO_2, transfer of the CO_2 stream and sequestration of the CO_2 stream.	Technically Feasible	90%	Economically Infeasible. Using the cost estimation methods from the NETL document, the cost of capture, compression, and transfer of CO2 via a pipeline was estimated to be approximately $244 per ton of CO2 removed from the amine unit and TEG dehydration unit. Therefore, based on the pipeline transfer cost, CCS is not regarded as an economically feasible CO2 control option.	No
		Overall Energy Efficiency	Design and construction using all new, energy efficient equipment. Electric engines for compression. Electric motors with variable speed drives. Seals equipped with detection or alarm points. Design specifications of the amine treater and TEG dehydrator to reduce heat duty. Flare that will burn natural gas during startup only and will operate on waste gas heat alone during normal operation. Compressed air for instrument control.	Technically Feasible	N/A - Selected as BACT	N/A - Selected as BACT	Yes
Hot Oil Heaters	GHGs	Oxygen Trim Controls	Oxygen monitors and intake air flow monitors can be used to optimize the fuel/air mixture. Combustion units operated with too much excess air may lead to inefficient combustion and additional energy will be needed to heat the excess air.	Technically Feasible	N/A - Selected as BACT	N/A - Selected as BACT	Yes
		Fuel Selection	Natural gas has the lowest carbon intensity of any available fuel for the heaters.	Technically Feasible	N/A - Selected as BACT	N/A - Selected as BACT	Yes
		Efficient Heater and Burner Design	Efficient heater design and air-to-fuel ratio improve mixing of fuel and create more efficient heat transfer.	Technically Feasible	N/A - Selected as BACT	N/A - Selected as BACT	Yes
		Heat Integration	The plant is equipped with multiple process to process cross heat exchangers for maximum heat integration and high efficiency mass transfer equipment to recover heat and reduce the overall energy use at the plant. The process to process cross heat exchangers minimize the size of the hot oil heaters to meet the process demands of the train. In addition, the Butane Splitter overheads compression scheme lowers the heating and cooling duty by 120 MMBtu/hr.	Technically Feasible	N/A - Selected as BACT	N/A - Selected as BACT	Yes
		Good Combustion, Operating, and Maintenance Practices	Good combustion and operating practices are a potential control option by improving the fuel efficiency of the process heaters. Good combustion practices also include proper maintenance and tune-up of the process heaters at least annually per the manufacturer's specifications.	Technically Feasible	N/A - Selected as BACT	N/A - Selected as BACT	Yes

Identify Emission Source: Emission Source	Identify Emission Source: PSD Pollutant	List Available Control Technologies: Control Technology	Description	Feasible/Infeasible	Evaluate Efficiency: Typical Control Efficiency	Evaluate Cost Effectiveness: Cost Effectiveness	Selected as BACT?
Flare (Pilot Gas Combustion, Amine Unit, TEG Dehydrator, and MSS Activities)	GHGs	Fuel Selection	Natural gas has the lowest carbon intensity of any available fuel.	Technically Feasible	N/A - Selected as BACT	N/A - Selected as BACT	Yes
		Flare Gas Recovery	Flaring can be reduced by installation of commercially available recovery systems, including recovery compressors and collection and storage tanks. The recovered gas is then utilized by introducing it into the fuel system as applicable.	Technically Infeasible. Due to infrequent MSS activities and the amount of gas sent to the flare , it is technically infeasible to re-route the flare gas to a process fuel system and hence, the gas will be combusted by the flare for control.	N/A - Technically Infeasible	N/A - Technically Infeasible	No
		Good Combustion, Operating, and Maintenance Practices	Good combustion and operating practices are a potential control option for improving the fuel efficiency of the flare. Good combustion practices include proper operation, maintenance, and tune-up of the flare.	Technically Feasible	N/A - Selected as BACT	N/A - Selected as BACT	Yes
		Good Flare Design	Good flare design can be employed to destroy large fractions of the flare gas. Good flare design includes pilot flame monitoring, flow measurement, and monitoring/control of waste gas heating valve.	Technically Feasible	N/A - Selected as BACT	N/A - Selected as BACT	Yes
		Limited Vent Gas Releases to Flare	Minimizing the number and duration of MSS activities and therefore limiting vent gases routed to the flare will help reduce emissions from MSS activities.	Technically Feasible	N/A - Selected as BACT	N/A - Selected as BACT	Yes
Fugitive Emissions	GHGs	Implementation of LDAR Program	LDAR programs have traditionally been developed for the control of VOC emissions. BACT determinations related to control of VOC emissions rely on technical feasibility, economic reasonableness, reduction of potential environmental impacts, and regulatory requirements for these instrumented programs. Instrumented monitoring implemented through the 28 VHP LDAR program, with control effectiveness of 97% for most equipment, is considered top-level BACT.	Technically Feasible	N/A - Selected as BACT	N/A - Selected as BACT	Yes
		Installation of Leakless Equipment	Leakless technology valves are available and currently in use, primarily where highly toxic or otherwise hazardous materials are used.	Technically Infeasible. Not demonstrated for GHG emission sources	N/A - Technically Infeasible	N/A - Technically Infeasible	No
		Alternative Monitoring Program - Remote Sensors / Infrared Technologies	Alternate monitoring programs such as remote sensing technologies have been proven effective in leak detection and repair. The use of sensitive infrared camera technology has become widely accepted as a cost effective means for identifying leaks of hydrocarbons.	Technically Feasible	N/A - Most effective control option (LDAR) is implemented.	N/A	No
		Audio/Visual/Olfactory (AVO) Monitoring Program	Leaking fugitive components can be identified through audio, visual, or olfactory (AVO) methods.	Technically Feasible	N/A - Selected as BACT	N/A - Selected as BACT	Yes
		Use High Quality Components and Materials of Construction Compatible with Process	The use of high quality equipment that is designed for the specific service in which it is employed results in effective control of fugitive emissions.	Technically Feasible	N/A - Selected as BACT	N/A - Selected as BACT	Yes

Summary of Proposed Good Combustion Practices [1]

Good Combustion Technique	Practice	Applicable Units	Standard
Operator practices	-Official documented operating procedures, updated as required for equipment or practice change -Procedures include startup, shutdown, malfunction -Operating logs/record keeping.	All combustion units	-Maintain written site specific operating procedures in accordance with GCPs, including startup, shutdown, malfunction.
Maintenance knowledge	-Training on applicable equipment & procedures.	All combustion units	-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 -Maintenance logs/record keeping.	All combustion units	-Maintain site specific procedures for best/optimum maintenance practices -Scheduled periodic evaluation, inspection, overhaul as appropriate.
Firebox (furnace) residence time, temperature, turbulence	-Supplemental stream injection into active flame zone -Residence time by design (incinerators) -Minimum combustion chamber temperature (incinerators).	Thermal Oxidizer and Flare	
Fuel quality analysis and fuel handling	-Monitor fuel quality -Fuel quality certification from supplier if needed -Periodic fuel sampling and analysis -Fuel handling practices - Targa Longhorn Gas Plant will use pipeline quality natural gas.	All combustion units	-Fuel analysis where composition could vary -Fuel handling procedures applicable to the fuel.
Combustion air distribution	-Adjustment of air distribution system based on visual observations -Adjustment of air distribution based on continuous or periodic monitoring.	All combustion units	-Routine & periodic adjustments & checks.

[1] EPA Guidance document "Good Combustion Practices" available at: http://www.epa.gov/ttn/atw/iccr/dirss/gcp.pdf.

12. PROFESSIONAL ENGINEER (P.E.) SEAL

The professional engineer (P.E.) seal is included in this section for the proposed project.

FORM PI-1 SECTION X PROFESSIONAL ENGINEER (P.E.) SEAL

I, Paul Greywall, have reviewed the following sections of the attached application for an initial new source review permit submitted by Targa:

Emissions Data

Best Available Control Technology

The capital cost of the project is estimated to be greater than $25,000,000.

The application for initial new source review, as referenced above, was reviewed on the 5th day of March 2012.

Signed: [signature]

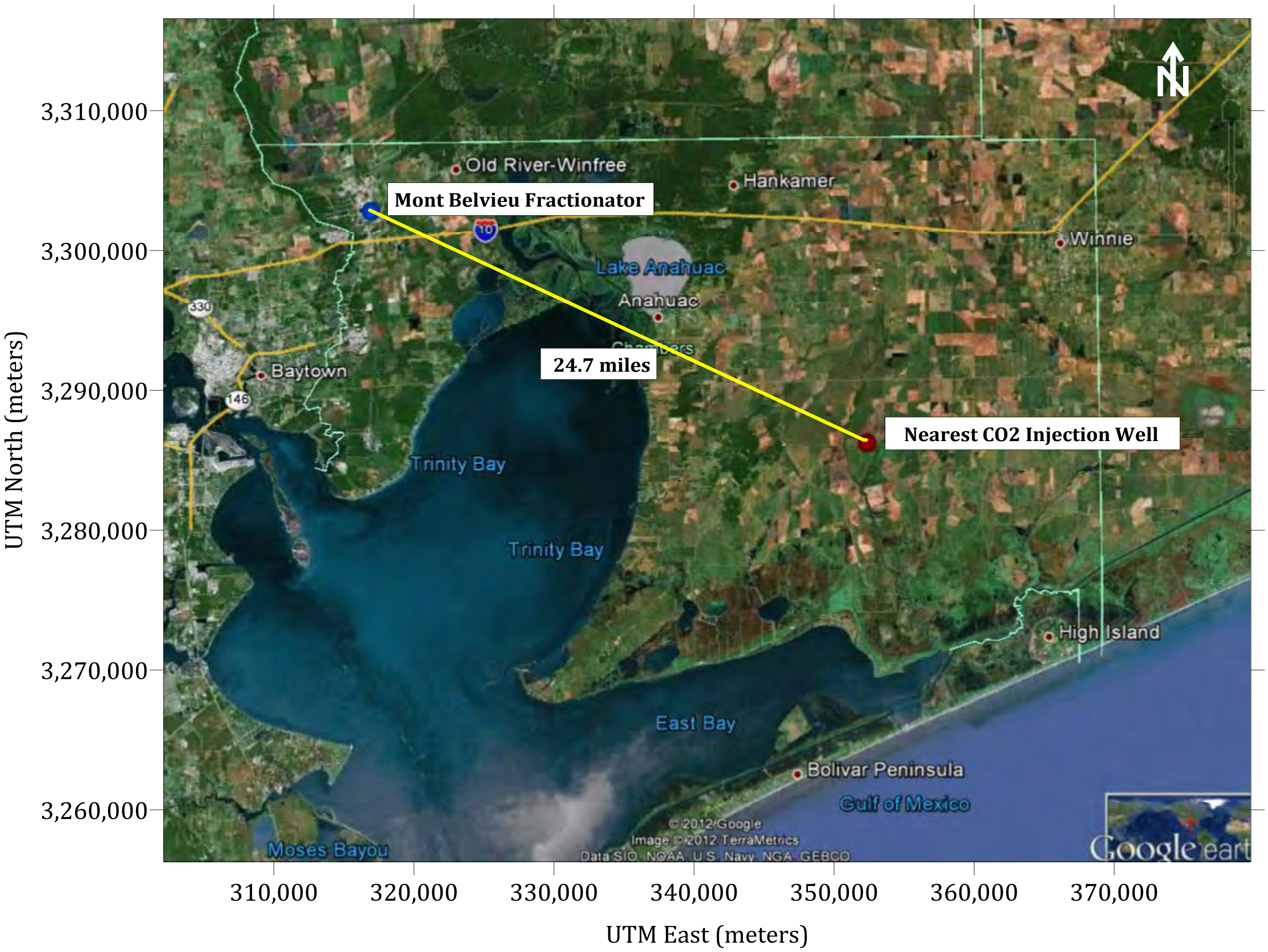
Date: 3/5/2012

Professional Engineer Registration Number: 105305

STATE OF TEXAS
PAUL F. GREYWALL
105305
LICENSED
PROFESSIONAL ENGINEER

Map of Nearest CO_2 Injection Well

Targa Midstream Services LLC
CCS Pipeline Distance Map



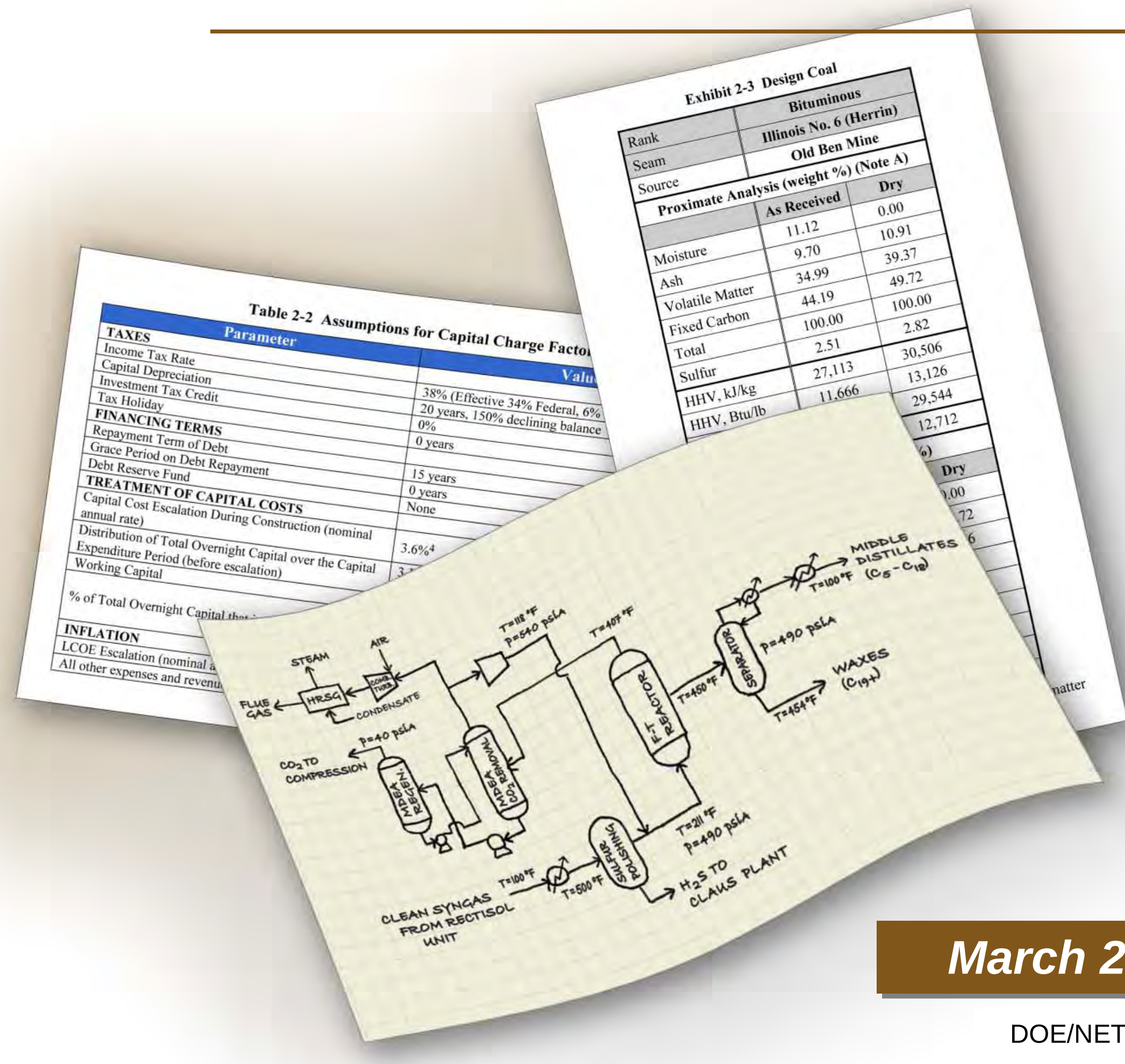
Reference UTM Coordinates are in NAD83.
Map image from Google Earth TM Mapping Service.

NETL Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs DOE/NETL-2010/1447

the ENERGY lab

QUALITY GUIDELINES FOR ENERGY SYSTEM STUDIES

Estimating Carbon Dioxide Transport and Storage Costs



March 2010

DOE/NETL-2010/1447

NATIONAL ENERGY TECHNOLOGY LABORATORY

U.S. DEPARTMENT OF ENERGY

Quality Guidelines for Energy Systems Studies
Estimating CO_2 Transport, Storage & Monitoring Costs

Background

This paper explores the costs associated with geologic sequestration of carbon dioxide (CO_2). This cost is often cited at the flat figure of $5-10 per short ton of CO_2 removed, but estimates can vary with values as high as $23 per short ton having been published recently [1, 2, 3]. The variability of these costs is due in part to the wide range of transportation and storage options available for CO_2 sequestration, but may also relate to the dramatic rise of construction and material costs in the United States which has occurred over the last several years. This paper examines the transportation of CO_2 via pipeline to, and storage of that CO_2 in, a geologic formation representative of those identified in North America as having storage potential based on data available from the literature.

Approach

Geologic sequestration costs were assessed based on the pipeline transport and injection of super-critical CO_2 into a geologic reservoir representative of those identified in North America as having storage potential. High pressure (2,200 psig) CO_2 is provided by the power plant or energy conversion facility and the cost and energy requirements of compression are assumed by that entity. CO_2 is in a super-critical state at this pressure which is desirable for transportation and storage purposes.

CO_2 exits the pipeline terminus at a pressure of 1,200 psig, and the pipeline diameter was sized for this to be achieved without the need for recompression stages along the pipeline length. This exit pressure specification: (1) ensures that CO_2 remains in a supercritical state throughout the length of the pipeline regardless of potential pressure drops due to pipeline elevation change[1]; (2) is equivalent to the reservoir pressure – exceeding it after hydrostatic head is accounted for – alleviating the need for recompression at the storage site; and (3) minimizes the pipeline diameter required, and in turn, transport capital cost.

The required pipeline diameter was calculated iteratively by determining the diameter required to achieve a 1,000 psig pressure drop (2,200 psig inlet, 1,200 psig outlet) over the specified pipeline distance, and rounding up to the nearest even sized pipe diameter. The pipeline was sized based on the CO_2 output produced by the power plant when it is operating at full capacity (100% utilization factor) rather than the average capacity.

The storage site evaluated is a saline formation at a depth of 4,055 feet (1,236 meters) with a permeability of 22 md and down-hole pressure of 1,220 psig (8.4 MPa) [4].[2] This is considered an average storage site and requires roughly one injection well for each 10,300 short tons of CO_2 injected per day [4]. An overview of the geologic formation characteristics are shown in Table 1.

Table 1: Deep, Saline Formation Specification [4]

Parameter	Units	Average Case
Pressure	MPa (psi)	8.4 (1,220)
Thickness	m (ft)	161 (530)
Depth	m (ft)	1,236 (4,055)
Permeability	Md	22
Pipeline Distance	km (miles)	80 (50)
Injection Rate per Well	tonne (short ton) CO_2/day	9,360 (10,320)

[1] Changes in pipeline elevation can result in pipeline pressure reductions due to head losses, temperature variations or other factors. Therefore a 10% safety margin is maintained to ensure the CO_2 supercritical pressure of 1,070 psig is exceeded at all times.
[2] "md", or millidarcy, is a measure of permeability defined as 10^{-12} Darcy.

Cost Sources & Methodology

The cost metrics utilized in this study provide a best estimate of T, S, & M costs for a "typical" sequestration project, and may vary significantly based on variables such as terrain to be crossed by the pipeline, reservoir characteristics, and number of land owners from which sub-surface rights must be acquired. Raw capital and operating costs are derived from detailed cost metrics found in the literature, escalated to June 2007-year dollars using appropriate price indices. These costs were then verified against values quoted by any industrial sources available. Where regulatory uncertainty exists or costs are undefined, such as liability costs and the acquisition of underground pore volume, analogous existing policies were used for representative cost scenarios.

The following sections describe the sources and methodology used for each metric.

Cost Levelization and Sensitivity Cases

Capital costs were levelized over a 30-year period and include both process and project contingency factors. Operating costs were similarly levelized over a 30-year period and a sensitivity analysis was performed to determine the effects of different pipeline lengths on overall and avoided costs as well as the distribution of transport versus storage costs.

In several areas, such as Pore Volume Acquisition, Monitoring, and Liability, cost outlays occur over a longer time period, up to 100 years. In these cases a capital fund is established based on the net present value of the cost outlay, and this fund is then levelized as described in the previous paragraph.

Following the determination of cost metrics, a range of CO_2 sequestration rates and transport distances were assessed to determine cost sensitivity to these parameters. Costs were also assessed in terms of both removed and avoided emissions cost, which requires power plant specific information such as plant efficiency, capacity factor, and emission rates. This paper presents avoided and removed emission costs for both Pulverized Coal (PC) and Integrated Gasification Combined Cycle (IGCC) cases using data from Cases 11 & 12 (Supercritical PC with and without CO_2 Capture) and Cases 1 & 2 (GEE Gasifier with and without CO_2 Capture) from the *Bituminous Baseline Study* [5].

Transport Costs

CO_2 transport costs are broken down into three categories: pipeline costs, related capital expenditures, and O&M costs.

Pipeline costs are derived from data published in the Oil and Gas Journal's (O&GJ) annual Pipeline Economics Report for existing natural gas, oil, and petroleum pipeline project costs from 1991 to 2003. These costs are expected to be analogous to the cost of building a CO_2 pipeline, as noted in various studies [4, 6, 7]. The University of California performed a regression analysis to generate the following cost curves from the O&GJ data: (1) Pipeline Materials, (2) Direct Labor, (3) Indirect Costs[3], and (4) Right-of-way acquisition, with each represented as a function of pipeline length and diameter [7].

Related capital expenditures were based on the findings of a previous study funded by DOE/NETL, *Carbon Dioxide Sequestration in Saline Formations – Engineering and Economic Assessment* [6]. This study utilized a similar basis for pipeline costs (Oil and Gas Journal Pipeline cost data up to the year 2000) but added a CO_2 surge tank and pipeline control system to the project.

Transport O&M costs were assessed using metrics published in a second DOE/NETL sponsored report entitled *Economic Evaluation of CO_2 Storage and Sink Enhancement Options* [4]. This study was chosen due to the reporting of O&M costs in terms of pipeline length, whereas the other studies mentioned above either (a)

[3] Indirect costs are inclusive of surveying, engineering, supervision, contingencies, allowances for funds used during construction, administration and overheads, and regulatory filing fees.

do not report operating costs, or (b) report them in absolute terms for one pipeline, as opposed to as a length- or diameter-based metric.

Storage Costs

Storage costs were broken down into five categories: (1) Site Screening and Evaluation, (2) Injection Wells, (3) Injection Equipment, (4) O&M Costs, and (5) Pore Volume Acquisition. With the exception of Pore Volume Acquisition, all of the costs were obtained from *Economic Evaluation of CO_2 Storage and Sink Enhancement Options* [4]. These costs include all of the costs associated with determining, developing, and maintaining a CO_2 storage location, including site evaluation, well drilling, and the capital equipment required for distributing and injecting CO_2.

Pore Volume Acquisition costs are the costs associated with acquiring rights to use the sub-surface area where the CO_2 will be stored, i.e. the pore space in the geologic formation. These costs were based on recent research by Carnegie Mellon University which examined existing sub-surface rights acquisition as it pertains to natural gas storage [8]. The regulatory uncertainty in this area combined with unknowns regarding the number and type (private or government) of property owners requires a number of “best engineering judgment” decisions to be made, as documented below under Cost Metrics.

Liability Protection

Liability Protection addresses the fact that if damages are caused by injection and long-term storage of CO_2, the injecting party may bear financial liability. Several types of liability protection schemas have been suggested for CO_2 storage, including Bonding, Insurance, and Federal Compensation Systems combined with either tort law (as with the Trans-Alaska Pipeline Fund), or with damage caps and preemption, as is used for nuclear energy under the Price Anderson Act [9].

At present, a specific liability regime has yet to be dictated either at a Federal or (to our knowledge) State level. However, certain state governments have enacted legislation which assigns liability to the injecting party, either in perpetuity (Wyoming) or until ten years after the cessation of injection operations, pending reservoir integrity certification, at which time liability is turned over to the state (North Dakota and Louisiana) [10, 11, 12]. In the case of Louisiana, a trust fund of five million dollars is established for each injector over the first ten years (120 months) of injection operations. This fund is then used by the state for CO_2 monitoring and, in the event of an at-fault incident, damage payments.

This study assumes that a bond must be purchased before injection operations are permitted in order to establish the ability and good will of an injector to address damages where they are deemed liable. A figure of five million dollars was used for the bond based on the Louisiana fund level. This Bond level may be conservative, in that the Louisiana fund covers both liability and monitoring, but that fund also pertains to a certified reservoir where injection operations have ceased, having a reduced risk compared to active operations. This cost may be updated as more specific liability regimes are instituted at the Federal or State levels. The Bond cost was not escalated.

Monitoring Costs

Monitoring costs were evaluated based on the methodology set forth in the IEA Greenhouse Gas R&D Programme’s *Overview of Monitoring Projects for Geologic Storage Projects* report [13]. In this scenario, operational monitoring of the CO_2 plume occurs over thirty years (during plant operation) and closure monitoring occurs for the following fifty years (for a total of eighty years). Monitoring is via electromagnetic (EM) survey, gravity survey, and periodic seismic survey, EM and gravity surveys are ongoing while seismic survey occurs in years 1, 2, 5, 10, 15, 20, 25, and 30 during the operational period, then in years 40, 50, 60, 70, and 80 after injection ceases.

Cost Metrics

The following sections detail the Transport, Storage, Monitoring, and Liability cost metrics used to determine CO_2 sequestration costs for the deep, saline formation described above. The cost escalation indices utilized to bring these metrics to June-2007 year dollars are also described below.

Transport Costs

The regression analysis performed by the University of California breaks down pipeline costs into four categories: (1) Materials, (2) Labor, (3) Miscellaneous, and (4) Right of Way. The Miscellaneous category is inclusive of costs such as surveying, engineering, supervision, contingencies, allowances, overhead, and filing fees [7]. These cost categories are reported individually as a function of pipeline diameter (in inches) and length (in miles) in Table 2 [7].

The escalated CO_2 surge tank and pipeline control system capital costs, as well as the Fixed O&M costs (as a function of pipeline length) are also listed in Table 2. Fixed O&M Costs are reported in terms of dollars per miles of pipeline per year.

Storage Costs

Storage costs were broken down into five categories: (1) Site Screening and Evaluation, (2) Injection Wells, (3) Injection Equipment, (4) O&M Costs, and (5) Pore Space Acquisition. Additionally, the cost of Liability Protection is also listed here for the sake of simplicity. Several storage costs are evaluated as flat fees, including Site Screening & Evaluation and the Liability Bond required for sequestration to take place.

As mentioned in the methodology section above, the site screening and evaluation figure of $4.7 million dollars is derived from *Economic Evaluation of CO_2 Storage and Sink Enhancement Options* [4]. Some sources in

Table 2: Pipeline Cost Breakdown [4, 6, 7]

Cost Type	Units	Cost
Pipeline Costs		
Materials	$ *Diameter (inches), Length (miles)*	$\$64{,}632 + \$1.85 \times L \times (330.5 \times D^2 + 686.7 \times D + 26{,}960)$
Labor	$ *Diameter (inches), Length (miles)*	$\$341{,}627 + \$1.85 \times L \times (343.2 \times D^2 + 2{,}074 \times D + 170{,}013)$
Miscellaneous	$ *Diameter (inches), Length (miles)*	$\$150{,}166 + \$1.58 \times L \times (8{,}417 \times D + 7{,}234)$
Right of Way	$ *Diameter (inches), Length (miles)*	$\$48{,}037 + \$1.20 \times L \times (577 \times D + 29{,}788)$
Other Capital		
CO_2 Surge Tank	$	$1,150,636
Pipeline Control System	$	$110,632
O&M		
Fixed O&M	$/mile/year	$8,632

industry, however, have quoted significantly higher costs for site screening and evaluation, on the magnitude of $100 to $120 million dollars. The higher cost may be reflective of a different criteria utilized in assessing costs, such as a different reservoir size – the reservoir assessed in the higher cost case could be large enough to serve 5 to 7 different injection projects – or uncertainty regarding the success rate in finding a suitable reservoir. Future analyses will examine the sensitivity of overall T, S, and M costs to higher site evaluation costs.

Pore Space Acquisition costs are based on acquiring long-term (100-year) lease rights and paying annual rent to land-owners once the CO_2 plume has reached their property. Rights are acquired by paying a one-time $500 fee to land-owners before injection begins, as per CMU's design criteria [8]. When the CO_2 plume enters into the area owned by that owner (as determined by annual monitoring), the injector begins paying an annual "rent" of $100 per acre to that owner for the period of up to 100 years from plant start-up [8]. A 3% annual escalation rate is assumed for rental rate over the 100-year rental period [8]. Similar to the CMU study, this study assumes that the plume area will cover rights need to be acquired from 120 landowners, however, a sensitivity analysis found that the overall acquisition costs were not significantly affected by this: increasing the

Table 3: Geologic Storage Costs [4, 8, 11]

Cost Type	Units	Cost
Capital		
Site Screening and Evaluation	$	$4,738,488
Injection Wells	$/injection well *(see formula)*[1,2,3]	$\$240,714 \times e^{0.0008 \times well-depth}$
Injection Equipment	$/injection well *(see formula)*[2]	$\$94,029 \times \left(\frac{7,389}{280 \times \# of\ injection\ wells} \right)^{0.5}$
Liability Bond	$	$5,000,000
Declining Capital Funds		
Pore Space Acquisition	\$/short ton CO_2	\$0.334/short ton CO_2
O&M		
Normal Daily Expenses (Fixed O&M)	$/injection well	$11,566
Consumables (Variable O&M)	\$/yr/short ton CO_2/day	$2,995
Surface Maintenance (Fixed O&M)	*see formula*	$\$23,478 \times \left(\frac{7,389}{280 \times \# of\ injection\ wells} \right)^{0.5}$
Subsurface Maintenance (Fixed O&M)	$/ft-depth/inject. well	$7.08

[1]The units for the "well depth" term in the formula are meters of depth.
[2]The formulas at right describe the cost per injection well and in each case the number of injection wells should be multiplied the formula in order to determine the overall capital cost.
[3]The injection well cost is $508,652 per injection well for the 1,236 meter deep geologic reservoir assessed here.

number of owners to 120,000 resulted in a 110% increase in costs and a 1% increase in the overall LCOE of the plant [8]. However, this assumption will be revisited in future work.

To ensure that Pore Space Acquisition costs are met after injection ceases, a sinking capital fund is set up to pay for these costs by determining the present value of the costs over the 100-year period (30 years of injection followed by 70 additional years), assuming a 10% discount rate. The size of this fund – as described in Table 3 – is determined by estimating the final size of the underground CO_2 plume, based on both the total amount of CO_2 injected over the plant lifetime and the reservoir characteristics described in Table 1. After injection, the CO_2 plume is assumed to grow by 1% per year [9].

The remaining capital costs are based on the number of injection wells required, which has been calculated to be one injection well for every 10,320 short tons of CO_2 injected per day. O&M costs are based on the number of injection wells, the CO_2 injection rates, and injection well depth.

Monitoring Costs

Monitoring costs were evaluated based on the methodology set forth in the IEA Greenhouse Gas R&D Programme's *Overview of Monitoring Projects for Geologic Storage Projects* report [13]. In this scenario, operational monitoring of the CO_2 plume occurs over thirty years (during plant operation) and closure monitoring occurs for the following fifty years (for a total of eighty years). Monitoring is via electromagnetic (EM) survey, gravity survey, and periodic seismic survey, EM and gravity surveys are ongoing while seismic survey occurs in years 1, 2, 5, 10, 15, 20, 25, and 30 during the operational period, then in years 40, 50, 60, 70, and 80 after injection ceases.

Operational and closure monitoring costs are assumed to be proportional to the plume size plus a fixed cost, with closure monitoring costs evaluated at half the value of the operational costs. The CO_2 plume is assumed to grow from 18 square kilometers (km^2) after the first year to 310 km^2 in after the 30^{th} (and final) year of injection. The plume grows by 1% per year thereafter, to a size of 510 km^2 after the 80^{th} year [9].The present value of the life-cycle costs is assessed at a 10% discount rate and a capital fund is set up to pay for these costs over the eighty year monitoring cycle. The present value of the capital fund is equivalent to \$0.377 per short ton of CO_2 to be injected over the operational lifetime of the plant.

Cost Escalation

Four different cost escalation indices were utilized to escalate costs from the year-dollars they were originally reported in, to June 2007-year dollars. These are the Chemical Engineering Plant Cost Index (CEPI), U.S. Bureau of Labor Statistics (BLS) Producer Price Indices (PPI), Handy-Whitman Index of Public Utility Costs (HWI), and the Gross-Domestic Product (GDP) Chain-type Price Index [14, 15, 16].

Table 4 details which price index was used to escalate each cost metric, as well as the year-dollars the cost was originally reported in. Note that this reporting year is likely to be different that the year the cost estimate is from.

Cost Comparisons

The capital cost metrics used in this study result in a pipeline cost ranging from \$65,000 to \$91,000/inch-Diameter/mile for pipeline lengths of 250 and 10 miles (respectively) and 3 to 4 million metric tonnes of CO_2 sequestered per year. When project and process contingencies of 30% and 20% (respectively) are taken into account, this range increases to \$97,000 to \$137,000/inch-Diameter/mile. These costs were compared to contemporary pipeline costs quoted by industry experts such as Kinder-Morgan and Denbury Resources for verification purposes. Table 5 details typical rule-of-thumb costs for various terrains and scenarios as quoted by a representative of Kinder-Morgan at the Spring Coal Fleet Meeting in 2009. As shown, the base NETL cost metric falls midway between the costs quoted for "Flat, Dry" terrain (\$50,000/inch-Diameter/mile) and "High Population" or "Marsh, Wetland" terrain (\$100,000/inch-Diameter/mile), although the metric is closer to the "High Population" or "Marsh, Wetland" when contingencies are taken into account [17]. These costs were stated to be inclusive of right-of-way (ROW) costs.

Table 4: Summary of Cost Escalation Methodology

Cost Metric	Year-$	Index Utilized
Transport Costs		
Pipeline Materials	2000	HWI: Steel Distribution Pipe
Direct Labor (Pipeline)	2000	HWI: Steel Distribution Pipe
Indirect Costs (Pipeline)	2000	BLS: Support Activities for Oil & Gas Operations
Right-of-Way (Pipeline)	2000	GDP: Chain-type Price Index
CO_2 Surge Tank	2000	CEPI: Heat Exchangers & Tanks
Pipeline Control System	2000	CEPI: Process Instruments
Pipeline O&M (Fixed)	1999	BLS: Support Activities for Oil & Gas Operations
Storage Costs		
Site Screening/Evaluation	1999	BLS: Drilling Oil & Gas Wells
Injection Wells	1999	BLS: Drilling Oil & Gas Wells
Injection Equipment	1999	HWI: Steel Distribution Pipe
Liability Bond	2008	n/a
Pore Space Acquisition	2008	GDP: Chain-type Price Index
Normal Daily Expenses (Fixed)	1999	BLS: Support Activities for Oil & Gas Operations
Consumables (Variable)	1999	BLS: Support Activities for Oil & Gas Operations
Surface Maintenance	1999	BLS: Support Activities for Oil & Gas Operations
Subsurface Maintenance	1999	BLS: Support Activities for Oil & Gas Operations
Monitoring		
Monitoring	2004	BLS: Support Activities for Oil & Gas Operations

Ronald T. Evans of Denbury Resources, Inc. provided a similar outlook, citing pipeline costs as ranging from $55,000/inch-Diameter/mile for a project completed in 2007, $80,000/inch-Diameter/mile for a recently completed pipeline in the Gulf Region (no wetlands or swamps), and $100,000/inch-Diameter/mile for a currently planned pipeline, with route obstacles and terrain issues cited as the reason for the inflated cost of that pipeline [18, 19]. Mr. Evans qualified these figures as escalated due to recent spikes in construction and material costs, quoting pipeline project costs of $30,000/inch-Diameter-mile as recent as 2006 [18, 19].

A second pipeline capital cost comparison was made with metrics published within the 2008 IEA report entitled *CO_2 Capture and Storage: A key carbon abatement option*. This report cites pipeline costs ranging from $22,000/inch-Diameter/mile to $49,000/inch-Diameter/mile (once escalated to December-2006 dollars), between 25% and 66% less than the lowest NETL metric of $65,000/inch-Diameter/mile [20].

The IEA report also presents two sets of flat figure geologic storage costs. The first figure is based on a 2005 Intergovernmental Panel on Climate Change report is similar to the flat figure quoted by other entities, citing

Table 5: Kinder-Morgan Pipeline Cost Metrics [17]

Terrain	Capital Cost ($/inch-Diameter/mile)
Flat, Dry	$50,000
Mountainous	$85,000
Marsh, Wetland	$100,000
River	$300,000
High Population	$100,000
Offshore (150’-200’ depth)	$700,000

storage costs ranging from $0.40 to $4.00 per short ton of CO_2 removed [20]. This figure is based on sequestration in a saline formation in North America.

A second range of costs is also reported, citing CO_2 sequestration costs as ranging from $14 to $23 per short ton of CO_2 [13]. This range is based on a Monte Carlo analysis of 300 gigatonnes (Gt) of CO_2 storage in North America [20]. This analysis is inclusive of all storage options (geologic, enhanced oil recovery, enhanced coal bed methane, etc.), some of which are relatively high cost. This methodology may provide a more accurate cost estimate for large-scale, long-term deployment of CCS, but is a very high estimate for storage options that will be used in the next 50 to 100 years. For example, 300 Gt of storage represents capacity to store CO_2 from the next ~150 years of coal generation (2,200 million metric tonnes CO_2 per year from coal in 2007, assuming 90% capture from all facilities), meaning that certain high cost reservoirs will not come into play for another 100 or 150 years. This $14 to $23 per short ton estimate was therefore not viewed as a representative comparison to the NETL metric.

Results

Figure 1 describes the capital costs associated with the T&S of 10,000 short tons of CO_2 per day (2.65 million metric tonnes per year) for pipelines of varying length. This storage rate requires one injection well and is representative of the CO_2 produced by a 380 MW_g super-critical pulverized coal power plant, assuming 90% of the CO_2 produced by the plant is captured. Figure 2 presents similar information for Fixed, Variable, and total (assuming 100% capacity) operating expenses. In both cases, storage costs remain constant as the CO_2 flow rate and reservoir parameters do not change. Also, transport costs – which are dependent on both pipeline length and diameter – constitute the majority of the combined transport and storage costs for pipelines greater than 50 miles in length.

The disproportionately high cost of CO_2 transport (compared to storage costs) shown in Figures 1 and 2, and the direct dependence of pipeline diameter on the transport capital cost, prompted investigation into the effects of pipeline distance and CO_2 flow rate on pipeline diameter. Figure 3 describes the minimum required pipeline diameter as a function of pipeline length, assuming a CO_2 flow rate of 10,000 short tons per day (at 100%

Figure 1: Capital Cost vs. Pipeline Length

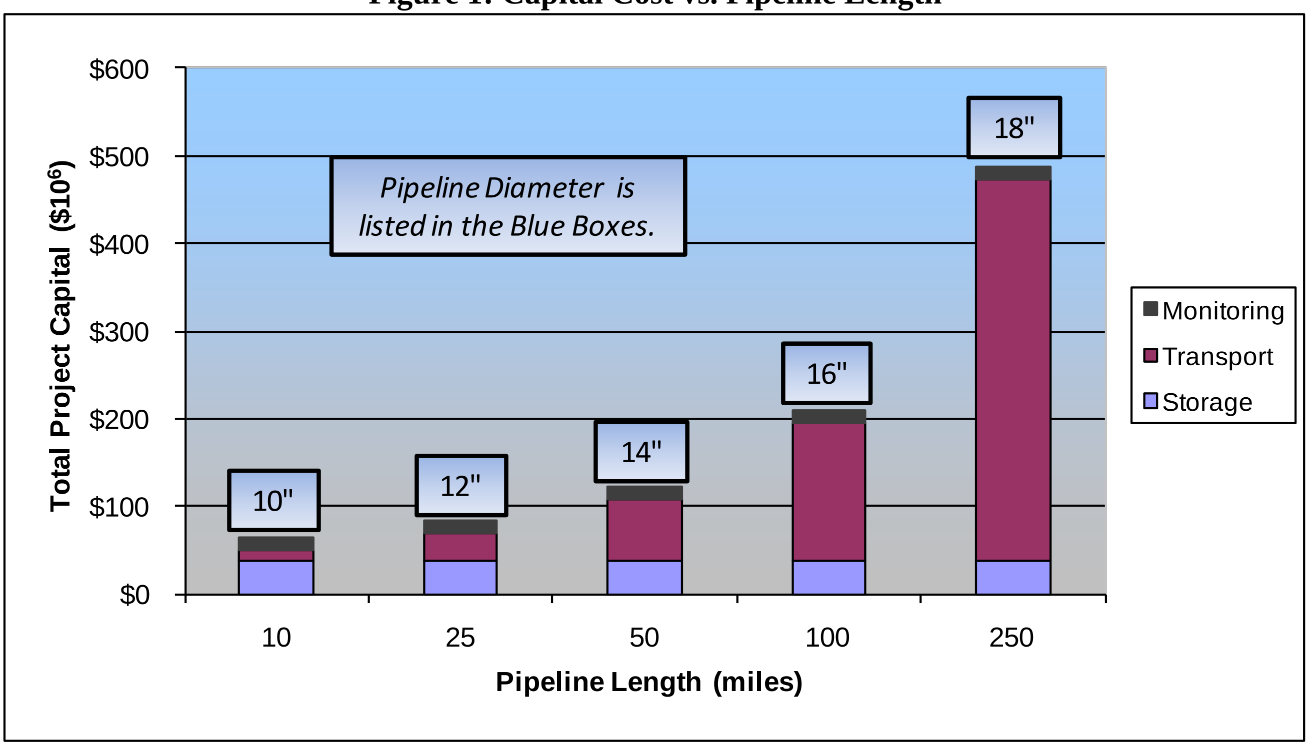
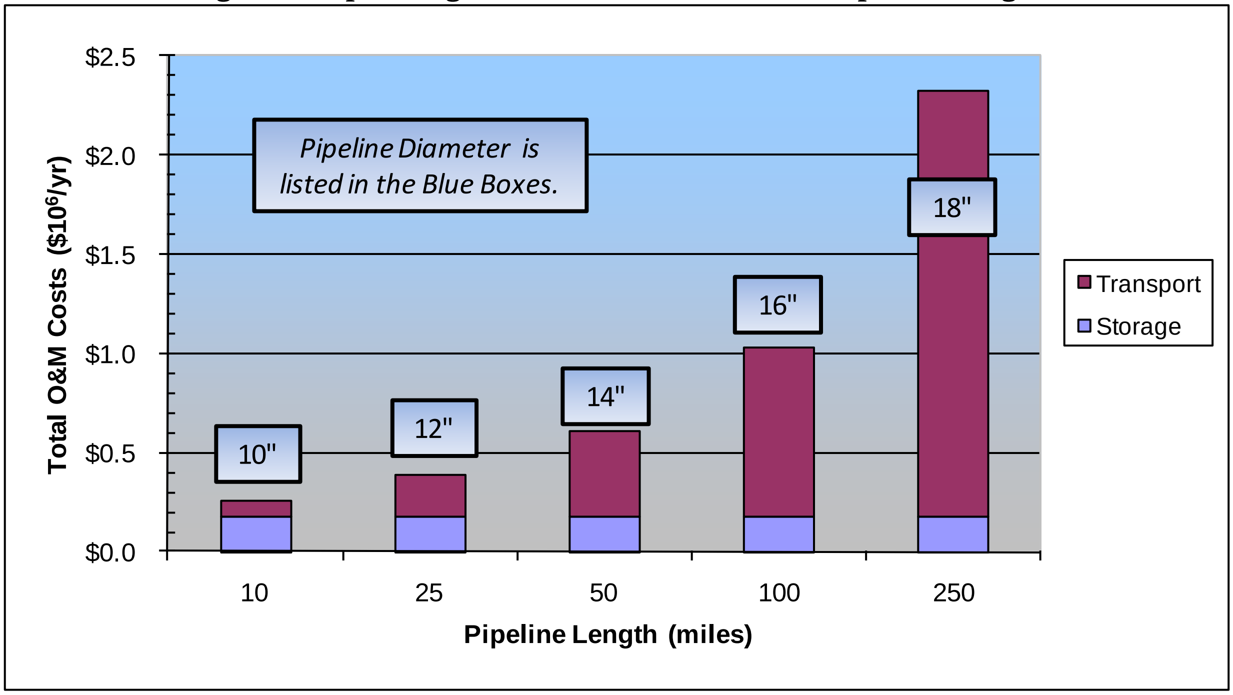


Figure 2: Operating and Maintenance Cost vs. Pipeline Length



utilization factor) and a pressure drop of 700 psi in order to maintain single phase flow in the pipeline (no recompression stages are utilized). Figure 4 is similar except that it describes the minimum pipe diameter as a function of CO_2 flow rate. A sensitivity analysis assessing the use of boost compressors and a smaller pipeline diameter has not yet been completed but may provide the ability to further reduce capital costs for sufficiently long pipelines.

Figure 3: Minimum Pipe Diameter as a function of Pipeline Length

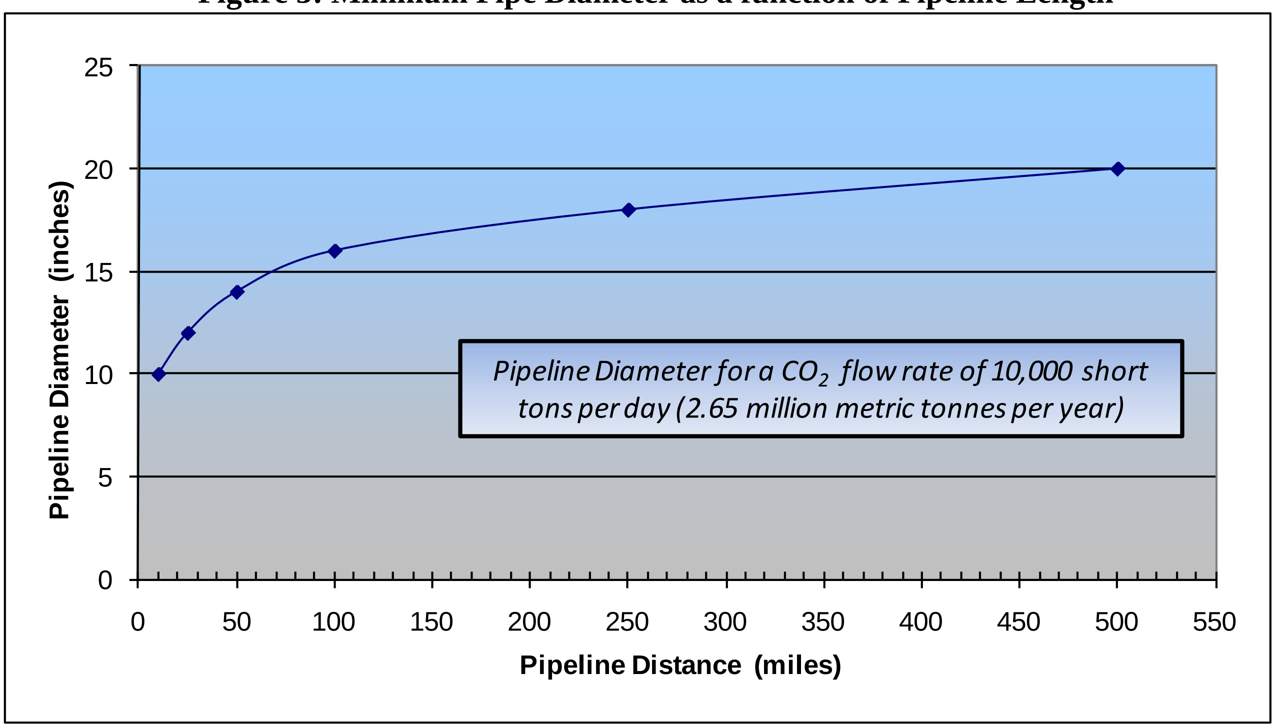
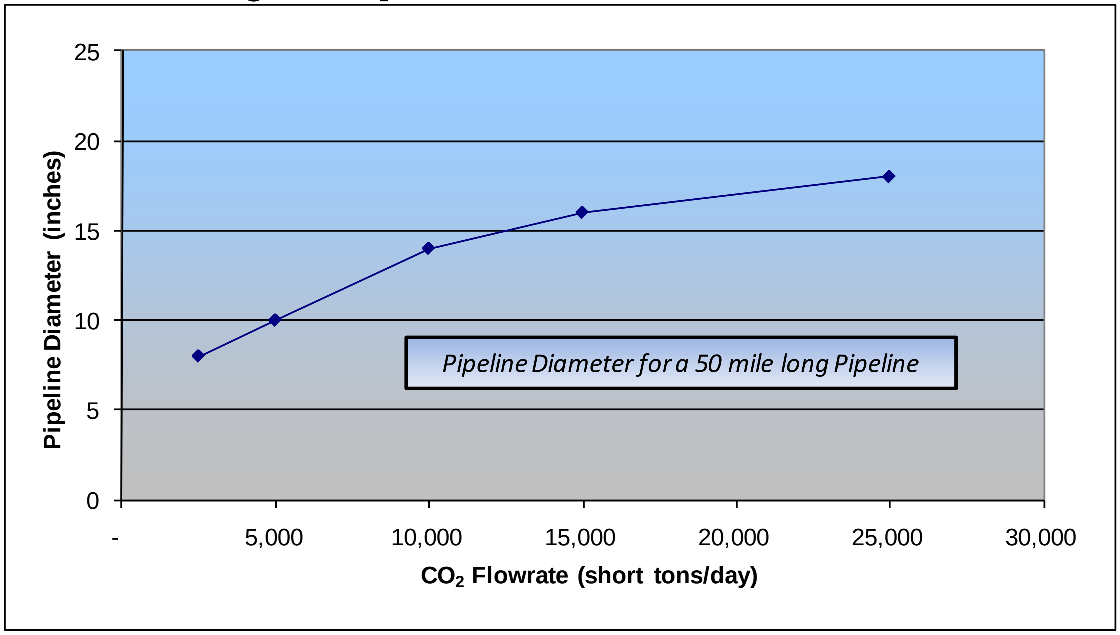


Figure 4: Pipe Diameter as a Function of CO_2 Flow Rate



Figures 5 and 6 describe the relationship of T&S costs to the flow rate of CO_2. The costs are evaluated for a 50 mile pipeline and a 700 psig CO_2 pressure drop over the length of the pipeline. Storage capital costs remain constant up until 10,000 short tons of CO_2 per day, above which a second injection well is needed and the cost increases as shown in Figure 5. A third injection well is needed for flow rates above 21,000 short tons per day and the capital requirement increases again for the 25,000 short tons per day flow rate due to an increase in pipeline diameter. Transport capital costs outweigh storage costs for all cases, as expected based on the results shown in Figure 1.

Unlike storage capital costs, the operating costs for storage constitute a significant portion of the total annual O&M costs – up to 44% at 25,000 short tons of CO_2 per day – as shown in Figure 6. Transport operating costs are constant with flow rate based on a constant pipeline length.

Figure 5: Capital Requirement vs. CO_2 Flow Rate

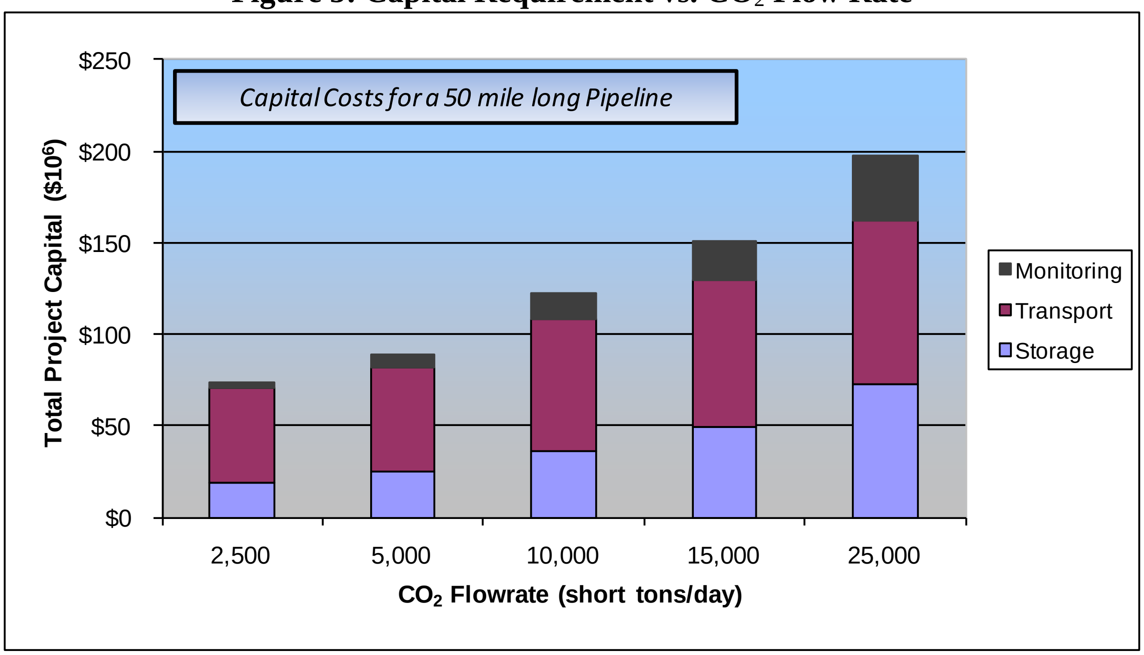
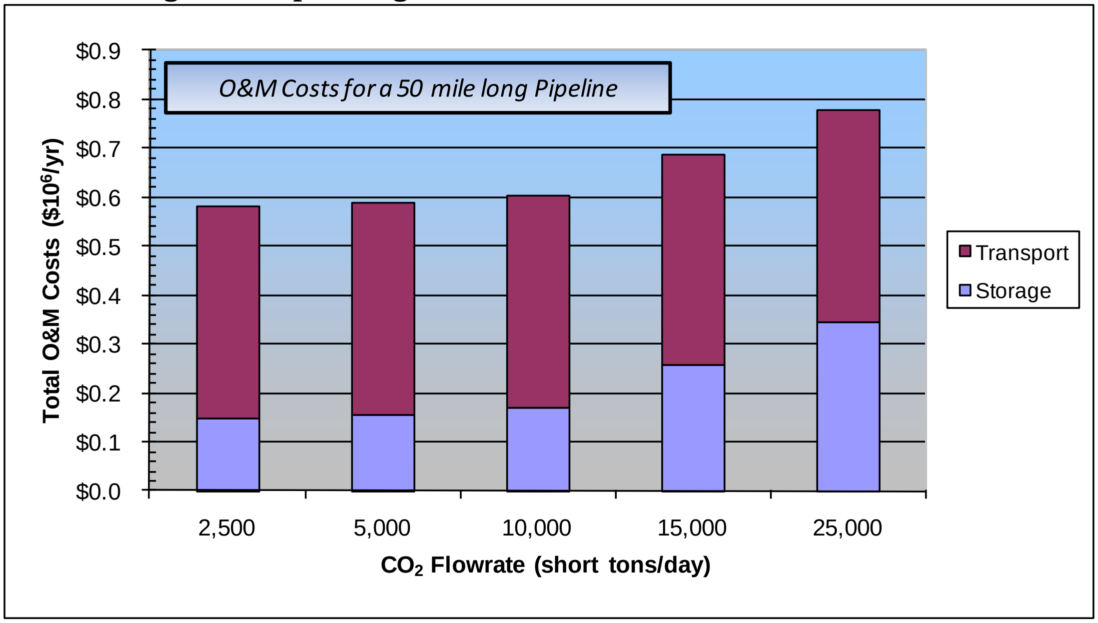
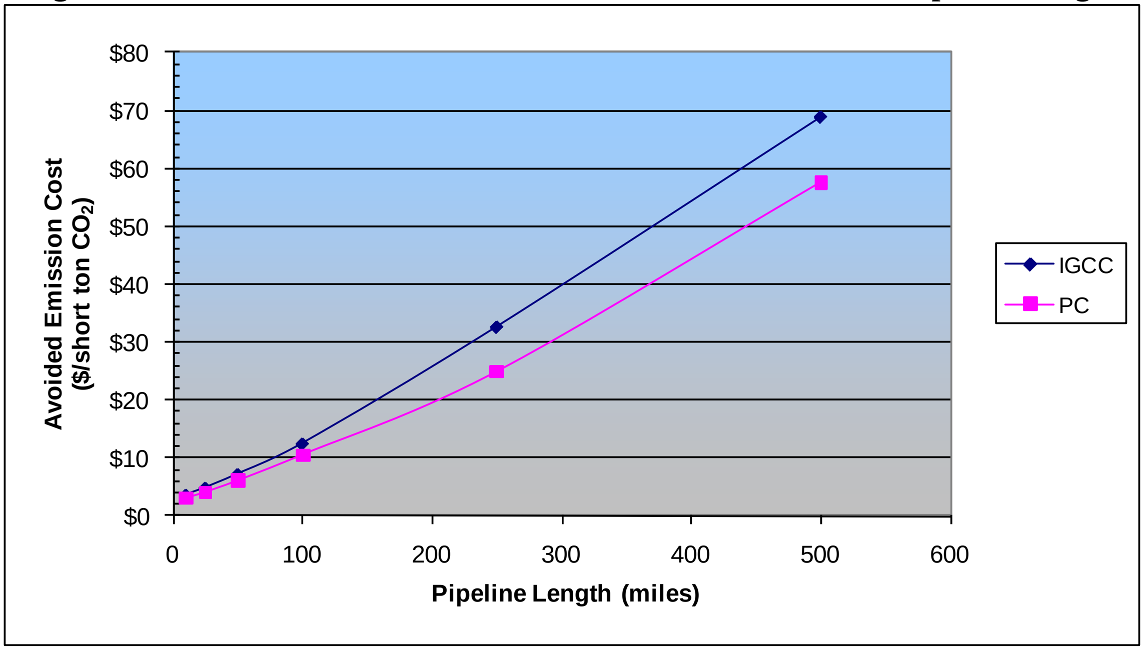


Figure 6: Operating and Maintenance Cost vs. CO_2 Flow Rate



Lastly, CO_2 avoidance and removal costs associated with T&S were determined for PC and IGCC reference plants found in the Baseline Study.[4] Because the CO_2 flow rate is defined by the reference plant, costs were determined as a function of pipeline length. Figure 7 shows that T&S avoided costs increase almost linearly with pipeline length and that there is very little difference between the PC and IGCC cases. This is the result of identical pipelines for each case (same distance, identical diameter) with only a change in capacity factor for each case. Figure 8 is similar to Figure 7 and shows the T&S removed emission cost.

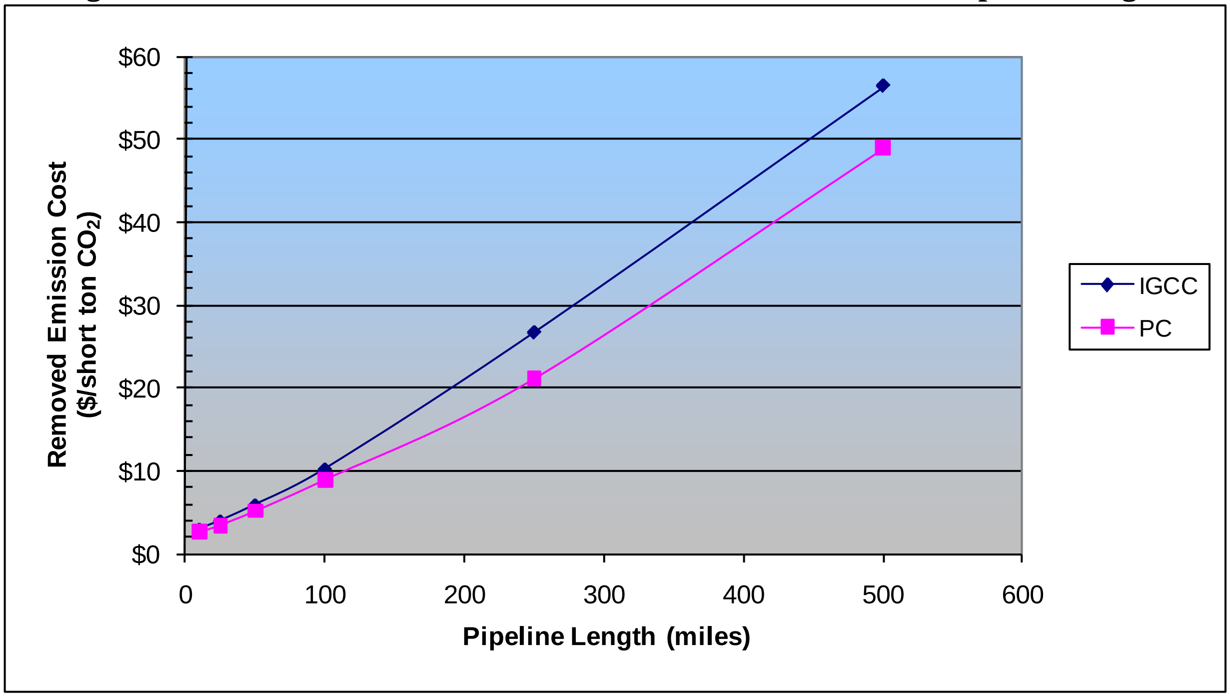
Figure 7: Avoided Emission Costs for 550 MW Power Plants vs. Pipeline Length



[4] Avoided cost calculations are based upon a levelized cost of electricity reported in Volume 1 of NETL's *Cost and Performance Baseline for Fossil Energy Plants* study. Electricity costs are levelized over a 30 year period, utilize a capital charge factor of 0.175, and levelization factors of 1.2022 and 1.1568 for coal costs and general O&M costs, respectively [3].

Addressing our initial topic, we see that our T&S avoided emission cost of $5 to $10 per short ton of CO_2 is associated with a pipeline length of 30 to 75 miles for the reference reservoir and our IGCC reference plant, or 50 to 95 miles for our PC reference plant. The T&S removal cost of $5 to $10 per short ton of CO_2 is associated with a pipeline length of 40 to 100 miles for an IGCC and 40 to 115 for a PC plant. Both of these ranges apply to the reference reservoir found in Table 1.

Figure 8: Removed Emission Costs for 550 MW Power Plants vs. Pipeline Length



Conclusions

- T&S avoided emission cost of $5 to $10 per short ton of CO_2 is associated with a pipeline length of 30 to 75 miles for our reference IGCC plant and the reference reservoir found in Table 1, or pipeline lengths of 50 to 95 miles for the PC plant.

- T&S removed emission cost of $5 to $10 per short ton of CO_2 is associated with a pipeline length of 40 to 100 miles for an IGCC and 40 to 115 for a PC plant. Both of these ranges apply to the reference reservoir found in Table 1.

- Capital costs associated with CO_2 storage become negligible compared to the cost of transport (i.e. pipeline cost) for pipelines of 50 miles or greater in length.

- Transport and storage operating costs are roughly equivalent for a 25 mile pipeline but transport constitutes a much greater portion of operating expenses at longer pipeline lengths.

- Transport capital requirements outweigh storage costs, independent of CO_2 flow rate, at a pipeline length of 50 miles and the reference reservoir.

- Operating expenses associated with storage approach transport operating costs for flow rates of 25,000 short tons of CO_2 per day at a 50 mile pipeline length.

Future Work

This paper has identified a number of areas for investigation in future work. These include:

- Investigation into the apparent wide variability in site characterization and evaluation costs, including a sensitivity analysis to be performed to determine the sensitivity of overall project costs across the reported range of values.
- Continued research into liability costs and requirements.
- Further evaluation and sensitivity analysis into the number of land-owners pore space rights will have to be acquired from for a given sequestration project.

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BACT Cost Analysis

Cost Estimation for Transfer of CO_2 via Pipeline - Flare (Controls Amine Unit and TEG Dehydration Unit)

CO_2 Pipeline and Emissions Data

Parameter	Value	Units
Minimum Length of Pipeline	24.7	miles
Average Diameter of Pipeline	8	inches
CO_2 emissions from Amine Unit and TEG Dehydration Unit	13,054	Short tons/yr
CO_2 Capture Efficiency	90%	
Captured CO_2	11,749	Short tons/yr

CO_2 Transfer Cost Estimation [1]

Cost Type	Units	Cost Equation	Cost ($)
Pipeline Costs			
Materials	$ Diameter (inches), Length (miles)	$64,632 + $1.85 x L x (330.5 x D² + 686.7 x D + 26,920)	$2,514,139.89
Labor	$ Diameter (inches), Length (miles)	$341,627 + $1.85 x L x (343.2 x D2 + 2,074 x D + 170,013)	$9,872,224.01
Miscellaneous	$ Diameter (inches), Length (miles)	$150,166 + $1.58 x L x (8,417 x D + 7,234)	$3,060,334.82
Right of Way	$ Diameter (inches), Length (miles)	$48,037 + $1.20 x L x (577 x D +29,788)	$1,067,771.56
Other Capital			
CO2 Surge Tank	$	$1,150,636	$1,150,636.00
Pipeline Control System	$	$110,632	$110,632.00
O&M			
Fixed O&M	$/mile/yr	$8,632	$213,210.40
		Total Pipeline Cost	**$17,988,948.68**

Amortized Cost Calculation

Equipment Life	10	years
Interest rate	8%	
= $i(1+i)^n/((1+i)n - 1)$	0.15	
Total Pipeline Installation Cost (TCI)	$17,775,738	$ (Pipeline + Other Capital)
Amortized Installation Cost (TCI *CRF)	$2,649,109	$/yr
Amortized Installation + O&M Cost	$2,862,320	$/yr
CO_2 Transferred	11,749	Short tons/yr
Annualized control cost per ton	**244**	**$/ton-yr**

[1] Cost estimation guidelines obtained from "Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs", DOE/NETL-
NOTE: This cost estimation does not include capital and O&M costs associated with the compression equipment or processing equipment.

TCEQ Equipment Tables and Table 2

TABLE 2

MATERIAL BALANCE

This material balance table is used to quantify possible emissions of air contaminants and special emphasis should be placed on potential air contaminants, for example: If feed contains sulfur, show distribution to all products. Please relate each material (or group of materials) listed to its respective location in the process flow diagram by assigning point numbers (taken from the flow diagram) to each material.

LIST EVERY MATERIAL INVOLVED IN EACH OF THE FOLLOWING GROUPS	Point No. from Flow Diagram	Process Rate (lbs/hr or SCFM) standard conditions: 70° F 14.7 PSIA. Check appropriate column at right for each process. [1]	Measurement	Estimation	Calculation
1. Raw Materials - Input					
Raw Liquified Petroleum Gas		100,000 bbl/day		X	
2. Fuels - Input					
Natural Gas		6.99 MMscf/day		X	
3. Products & By-Products - Output					
Ethane		50,000 bbl/day		X	
Propane		25,000 bbl/day		X	
Iso-Butane		5,000 bbl/day		X	
N-Butane		10,000 bbl/day		X	
Natural Gasoline		10,000 bbl/day		X	
4. Solid Wastes - Output					
5. Liquid Wastes - Output					
6. Airborne Waste (Solid) - Output	See Table 1(a)	See Emissions Data section			X
7. Airborne Wastes (Gaseous) - Output	See Table 1(a)	See Emissions Data section			X

[1] Process rates are nominal and will fluctuate based on raw LPG composition.

TABLE 6

BOILERS AND HEATERS

Type of Device: Hot Oil Heaters	Manufacturer:
Number from flow diagram: F5A and F5B	Model Number:

CHARACTERISTICS OF INPUT

Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
Natural Gas	See attached emission calculations for Residue Gas composition		Average	Design Maximum
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units) 1,015 Btu/scf	Average _____ scfm* ___% excess (vol)	Design Maximum ______ scfm * ______% excess (vol)

HEAT TRANSFER MEDIUM

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

OPERATING CHARACTERISTICS

Ave. 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.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp°F	scfm
4'-4" x 3' -1"	122 ft	61.85 ft/sec		410	

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Volume)
	See attached emission calculations

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

Also supply an assembly drawing, dimensioned and to scale, in plan, 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	Manufacturer & Model No. (if available)
EPN FLR-5	

CHARACTERISTICS OF INPUT

Waste Gas Stream	Material	Min. Value Expected	Ave. Value Expected	Design Max.
		(scfm [68°F,14.7 psia])	(scfm [68°F, 14.7 psia])	(scfm [68°F, 14.7 psia])
	1. TEG-2 waste streams	See attached emission calculations for details		
	2. AU-4 waste streams			
	3. Maintenance			
	4. Startup			
	5. Shutdown			
	6.			
	7.			
	8.			
% of time this condition occurs				

	Flow Rate (scfm [68°F, 14.7 psia])		Temp. °F	Pressure (psig)
	Minimum Expected	Design Maximum		
Waste Gas Stream	See attached emission calculations for details			
Fuel Added to Gas Steam				

	Number of Pilots	Type Fuel	Fuel Flow Rate (scfm [70°F & 14.7 psia]) per pilot
	4	Natural Gas	0.833 scfm/pilot

For Stream Injection	Stream Pressure (psig)		Total Stream Flow	Temp. °F	Velocity (ft/sec)
	Min. 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) 185 ft	Flare tip inside diameter (ft) 5.5 ft
Capital Installed Cost $__________	Annual Operating Cost $__________

Supply an assembly drawing, dimensioned and to scale, to show clearly the operation of the flare system. Show interior dimensions and features of the equipment necessary to calculate its performance. Also describe the type of ignition system and its method of operation. Provide an explanation of the control system for steam flow rate and other operating variables.

TCEQ Minor NSR Permit Application

TCEQ AIR QUALITY NEW SOURCE REVIEW INITIAL PERMIT APPLICATION

Targa Midstream Services LLC > Mont Belvieu Plant Train 5

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March 2012

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APPENDIX A. GRI-GLYCALC INPUT AND OUTPUT FILES

APPENDIX B. TCEQ EQUIPMENT TABLES AND TABLE 2

APPENDIX C. GHG PSD PERMIT APPLICATION

Targa Midstream Services LLC (Targa) operates a natural gas liquids (NGL) fractionator called the Mont Belvieu Plant in Mont Belvieu, Chambers County, Texas. The site is designed to fractionate NGLs into specification NGL components (ethane, propane, iso-butane, normal-butane and natural gasoline). A portion of the natural gasoline produced is further processed to remove contained sulfur compounds and to saturate contained benzene. In addition to the fractionation system, gas dehydrating units and hydrotreating systems, other sources of air emissions include flares (process and back-up), fugitives and utility systems (boilers for steam production, fire water pumps, and emergency generator pumps).

The Mont Belvieu Plant is considered an existing major source with respect to the Prevent of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) permitting programs. Targa is proposing to construct a new fractionation train (Train 5) at the facility, which will be operated independent of existing operations at the facility. Installation of the proposed fractionation train will not be a major modification with respect to any criteria pollutants. Targa is submitting this air quality new source review (NSR) permit application to authorize construction of the proposed fractionation train.

The Mont Belvieu Plant operates under Texas Commission on Environmental Quality (TCEQ) Air Quality Account Number CI-0022-A. Targa has been assigned TCEQ Customer Reference Number (CN) 601301559, and the Mont Belvieu Plant has been assigned Regulated Entity Reference Number (RN) 100222900. The existing emission sources at the Mont Belvieu Plant are currently authorized under NSR permits, various Standard Exemptions, Permits by Rule (PBRs), and Standard Permits, as further discussed in Section 1.3 of this permit application.

1.1. PROPOSED PROJECT

With this application, Targa is proposing to build a new fractionation train at the Mont Belvieu Plant. The proposed project will include the following equipment:

- Fractionation train and ancillary equipment
- Amine unit
- Tri-ethylene glycol (TEG) dehydration unit
- Cooling tower
- Hot oil heaters (2)
- Fugitives
- Atmospheric storage tanks

1.2. PERMITTING CONSIDERATIONS

1.2.1. PSD and NNSR Permitting Requirements

The Mont Belvieu Plant is located in Chambers County, which is currently designated as a serious nonattainment area for the eight-hour ozone standard and an attainment/unclassified area for all other pollutants.[1] The site is considered an existing major source under the PSD and NNSR permitting programs. As shown in Section 10 of this application, this proposed permitting action does not constitute a PSD major modification and PSD review is not triggered.

[1] Per 40 CFR §81.344 (Effective October 31, 2008).

NNSR applicability is determined based on the increase in emissions of oxides of nitrogen (NO_x) and volatile organic compounds (VOCs) from the proposed project. The increases in VOC and NO_x emissions from the proposed project, without regard to decreases, are greater than five tons per year (tpy); therefore, netting is required. However, federal NNSR review is not triggered as contemporaneous netting results in less than a 25 tpy increase for each pollutant. The netting analysis is presented in Section 10 of this application.

1.2.2. Greenhouse Gas Permitting Requirements

The Mont Belvieu Plant is an existing major source with respect to greenhouse gas (GHG) emissions under the PSD program because the site currently has a potential to emit greater than 100,000 tpy of carbon dioxide equivalent (CO_2e). The proposed project will be a major modification with respect to GHG emissions and subject to PSD permitting requirements as the U.S. Environmental Protection Agency (EPA) has interpreted them in the GHG Tailoring Rule.[2] In the Tailoring Rule, EPA established a major source threshold of 100,000 tpy CO_2e for new GHG sources and a major modification threshold of 75,000 tpy CO_2e for existing major sources. Targa has determined that the GHG emissions from the proposed project will exceed 75,000 tpy as shown in the GHG PSD application included in Appendix C of this TCEQ application. As a result, Targa has concluded that the proposed project will be a major modification with respect to GHGs.

With a final action published in May 2011, EPA promulgated a Federal Implementation Plan (FIP) to implement the permitting requirements for GHGs in Texas, and EPA assumed the role of permitting authority for Texas GHG permit applications with that action.[3] Therefore, GHG emissions from the proposed project are subject to the jurisdiction of the EPA under authority EPA has asserted in Texas through its FIP for the regulation of GHGs. TCEQ remains the permitting authority for all non-GHG criteria pollutants.

As shown in Section 10 of this permit application, the proposed project will be a minor modification with respect to all non-GHG pollutants. Therefore, all non-GHG emissions from the proposed project are subject to the jurisdiction of the TCEQ for minor source state NSR permitting. Accordingly, Targa is submitting applications to both EPA and TCEQ to obtain the requisite authorizations to construct. The GHG PSD application submitted to EPA is included in Appendix C of this TCEQ NSR permit application for reference.

[2] Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, 75 Fed. Reg. 31,514 (June 3, 2010).

[3] Determinations Concerning Need for Error Correction, Partial Approval and Partial Disapproval, and Federal Implementation Plan Regarding Texas's Prevention of Significant Deterioration Program, 76 Fed. Reg. 25,178 (May 3, 2011).

1.3. CURRENT AUTHORIZATIONS

As noted above, the existing sources located at the Mont Belvieu Plant are authorized via NSR permits, various Standard Exemptions, PBRs, and Standard Permits. The following table outlines the current active permits and registrations that exist at the Mont Belvieu Plant.

Table 1.3-1. Current Authorizations

Program	Permit/Registration Number
Air New Source Permit	5452
Air New Source Permit	56431
Air New Source Permit	56435
Standard Permit for Electric Generating Units	84814
Standard Permit for Pollution Control Projects	85385
Standard Permit for Oil & Gas Production Facilities	91519
Standard Permit for Oil & Gas Production Facilities	94872
Standard Permit for Pollution Control Projects	95200

PBR Registration No. 94786 and Standard Permit No. 98061 are currently shown as active authorizations in TCEQ's Central Registry. These projects were associated with temporary equipment that is no longer in use at the Mont Belvieu Plant. Targa will submit requests to TCEQ for these registrations to be voided.

The proposed Train 5 expansion will operate independently of all existing operations at the Mont Belvieu Plant. It will not rely on nor will it affect any of the existing processes or equipment at the plant.

1.4. PERMIT APPLICATION

This permit application was prepared in accordance with Title 30 of the Texas Administrative Code (30 TAC) Chapter 116, Subchapter B, New Source Review Permits. This application includes a TCEQ Form PI-1, other applicable TCEQ forms, a Best Available Control Technology (BACT) evaluation, emission calculations, process description and flow diagram, and other supporting documentation.

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: Targa Midstream Services LLC		
Texas Secretary of State Charter/Registration Number (*if applicable*):		
B. Company Official Contact Name: Hunter Battle		
Title: Vice President Logistics and Marketing Assets		
Mailing Address: 1000 Louisiana Street, Suite 4300		
City: Houston	State: TX	ZIP Code: 77002
Telephone No.: 713-584-1443	Fax No.:	E-mail Address:
C. Technical Contact Name: Dena Taylor		
Title: Sr. Environmental Specialist		
Company Name: Targa Midstream Services LLC		
Mailing Address: 10319 Highway 146		
City: Mont Belvieu	State: TX	ZIP Code: 77523
Telephone No.: 281-385-3165	Fax No.: 281-385-3187	E-mail Address: dtaylor@targaresources.com
D. Site Name: Mont Belvieu Fractionator		
E. Area Name/Type of Facility: Natural Gas Liquids Extraction and Processing	☒ Permanent ☐ Portable	
F. Principal Company Product or Business: Natural Gas Liquids		
Principal Standard Industrial Classification Code (SIC): 1321		
Principal North American Industry Classification System (NAICS):		
G. Projected Start of Construction Date: 3/1/2013		
Projected Start of Operation Date: 7/1/2013		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: 10319 Highway 146		
City/Town: Mont Belvieu	County: Chambers	ZIP Code: 77523
Latitude (nearest second): 29:50:31	Longitude (nearest second): 94:53:44	

I. Applicant Information (continued)	
I. Account Identification Number (leave blank if new site or facility): CI-0022-A	
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): CN601301559	
L. Regulated Entity Number (RN): RN100222900	
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: 22	
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: Craig Eiland	District No.: 23
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):	
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:____________________	
D. Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c).	☐ YES ☒ NO

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.): O-612	
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 ☐	

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*): **Please see Emission Data Section in Report**	
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):		
Hazardous Air Pollutants (HAPs):		
Other speciated air contaminants **not** listed above:		

Texas Commission on Environmental Quality
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V. Public Notice Information (complete if applicable)		
A. Public Notice Contact Name: Dena Taylor		
Title: Sr. Environmental Specialist		
Mailing Address: 10319 Highway 146		
City: Mont Belvieu	State: TX	ZIP Code: 77523
B. Name of the Public Place: West Chambers Branch Library		
Physical Address (No P.O. Boxes): 10616 Eagle Drive		
City: Mont Belvieu	County: Chambers	ZIP Code: 77680
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:

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? Spanish			
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 ☒			

VII. Technical Information			
B. Are any schools located within 3,000 feet of this facility?			☐ YES ☒ NO
C. Maximum Operating Schedule:			
Hours: 24 hr/day	Day(s): 7 day/wk	Week(s): 52 wk/yr	Year(s): 8,760 hr/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

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: 551474	Fee Amount: $75,000
Company name on check: Targa Resources Partners LP	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

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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: Hunter Battle

Signature: Hunter Battle
Original Signature Required

Date: MARCH 19, 2012

3. PERMIT APPLICATION FEE (TCEQ TABLE 30)

Pursuant to 30 TAC Section (§)116.141, the permit fee for a construction permit application is based on the capital cost of the proposed project. The permit fee is determined as 0.3% of the capital cost of the proposed project with a minimum fee of $900 and a maximum fee of $75,000.

The associated capital costs with this permit application are the construction of the proposed project; therefore, the maximum fee of $75,000 will be paid. TCEQ Table 30 is included at the end of this section. Targa has submitted a check in this amount to the TCEQ Revenue Section under separate cover.

Because the capital cost of the project will be more than $2,000,000, a Professional Engineer (P.E.) review has been conducted on the emission estimates and BACT analysis. The P.E. seal is included in Section 13 of this permit application.

Texas Commission on Environmental Quality
Table 30
Estimated Capital Cost and Fee Verification

Include estimated cost of the equipment and services that would normally be capitalized according to standard and generally accepted corporate financing and accounting procedures. Tables, checklists, and guidance documents pertaining to air quality permits are available from the Texas Commission on Environmental Quality, Air Permits Division Web site at www.tceq.state.tx.us/nav/permits/air_permits.html.

I. **DIRECT COSTS [30 TAC § 116.141(c)(1)]**	**Estimated Capital Cost**
A. A process and control equipment not previously owned by the applicant and not currently authorized under this chapter	$
B. Auxiliary equipment, including exhaust hoods, ducting, fans, pumps, piping, conveyors, stacks, storage tanks, waste disposal facilities, and air pollution control equipment specifically needed to meet permit and regulation requirements	$
C. Freight charges	$
D. Site preparation, including demolition, construction of fences, outdoor lighting, road and parking areas	$
E. Installation, including foundations, erection of supporting structures, enclosures or weather protection, insulation and painting, utilities and connections, process integration, and process control equipment	$
F. Auxiliary buildings, including materials storage, employee facilities, and changes to existing structures	$
G. Ambient air monitoring network	$
II. **INDIRECT COSTS [30 TAC § 116.141(c)(2)]**	**Estimated Capital Cost**
A. Final engineering design and supervision, and administrative overhead	$
B. Construction expense, including construction liaison, securing local building permits, insurance, temporary construction facilities, and construction clean-up	$
C. Contractor's fee and overhead	$
TOTAL ESTIMATED CAPITAL COST	$ > 25,000,000

I certify that the total estimated capital cost of the project as defined in 30 TAC § 116.141 is equal to or less than the above figure. I further state that I have read and understand Texas Water Code § 7.179, which defines CRIMINAL OFFENSES for certain violations, including intentionally or knowingly making, or causing to be made, false material statements or representations.

Company Name: Targa Midstream Services LLC

Company Representative Name (please print): Hunter Battle Title: Vice President Logistics and Marketing Assets

Company Representative Signature: [signature]

Estimated Capital Cost		**Permit Application Fee**	**PSD/Nonattainment Application Fee**
Less than	**$300,000**	**$900 (minimum fee)**	**$3,000 (minimum fee)**
$300,000 to	**$25,000,000**	**0.30% of capital cost**	
$300,000 to	**$7,500,000**		**1.0% of capital cost**
Greater than	**$25,000,000**	**$75,000 (maximum fee)**	
Greater than	**$7,500,000**		**$75,000 (maximum fee)**

PERMIT APPLICATION FEE (from table above) = $75,000 Date: MARCH 19, 2012

WARNING – THIS CHECK IS PROTECTED BY SPECIAL SECURITY GUARD PROGRAM™ FEATURES

Targa Resources Partners LP
1000 Louisiana
Suite 4300
Houston, TX 77002

JPMorgan Chase Bank, N.A.
Chicago, IL

CHECK NO. **551474**
CHECK DATE **03/02/2012**

70-2322/719
709373500

CHECK AMOUNT
$75,000.00

* * * Seventy Five Thousand Dollars Only*************

Pay To The Order Of
TEXAS COMMISSION ON ENVIRONMENTAL
QUALITY
REVENUE SECTION MC214
P O BOX 13088
AUSTIN TX 78711-3088

SECURE FEATURES INCLUDE INVISIBLE FIBERS • MICROPRINTING • VOID FEATURE PANTOGRAPH • ENDORSEMENT BACKER • BROWNSTAIN CHEMICAL REACTANT

⑈000551474⑈ ⑆071923226⑆ 709373500⑈

PAY TO:
TEXAS COMMISSION ON ENVIRONMENTAL
QUALITY
REVENUE SECTION MC214
P O BOX 13088
AUSTIN TX 78711-3088

Targa Resources Partners LP **Page 1 of 1**

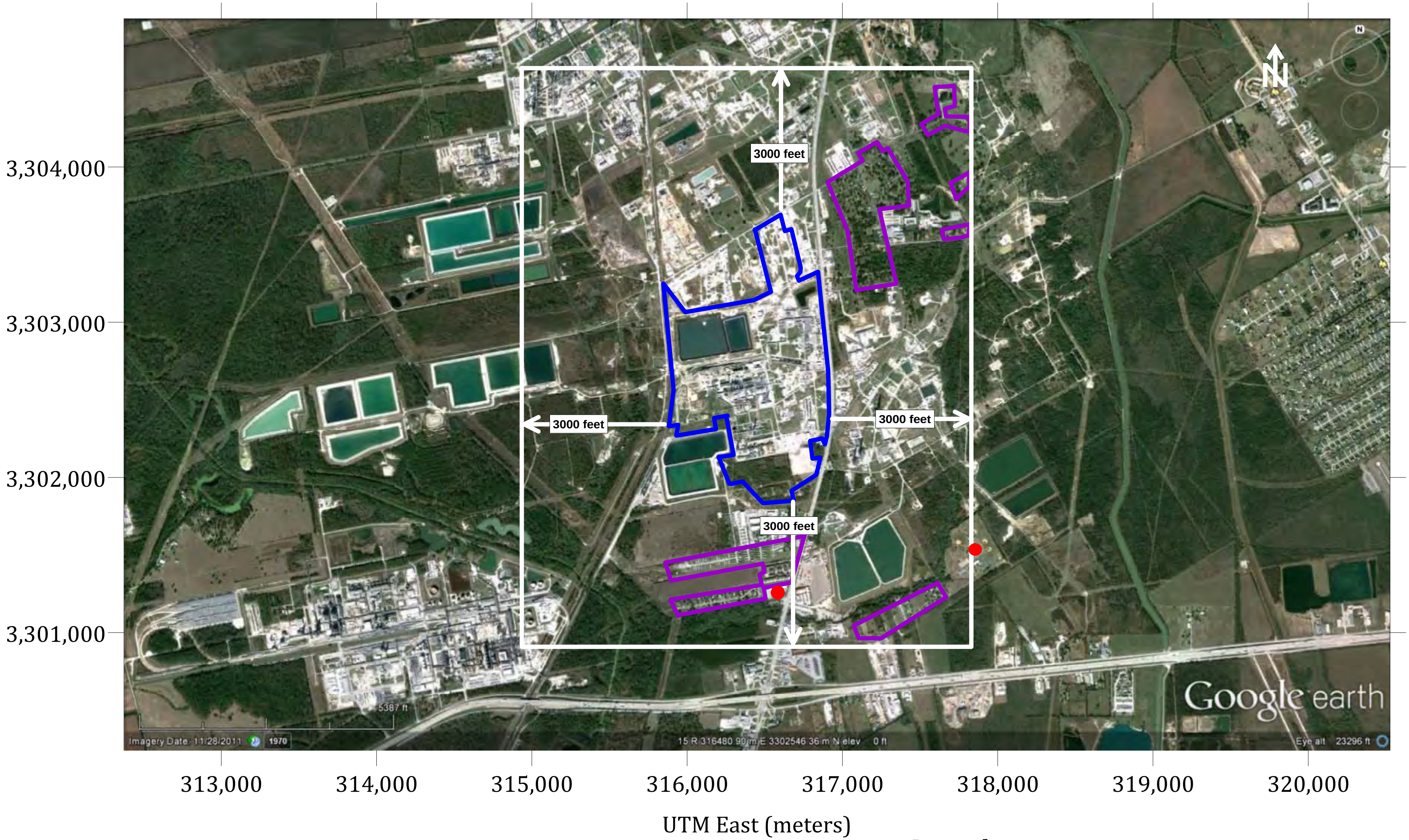
VENDOR NO.	CHECK DATE	CHECK NO	CHECK TOTAL
37856	**3/2/2012**	**551474**	**$75,000.00**

VOUCHER NUMBER	INVOICE NUMBER	INVOICE DATE		AMOUNT PAID
00206636	02292012	20120229	X JO BURNETTE	$ 75,000.00

4. AREA MAP

The Mont Belvieu Plant is located in Chambers County, Texas. An area map is included in this section to graphically depict the location of the facility with respect to the surrounding topography. Figure 4-1 is an area map centered on the Mont Belvieu Plant that extends out at least 3,000 feet from the property line in all directions. The map depicts the fenceline/property line with respect to predominant geographic features (such as highways, roads, streams, and railroads). There are no schools within 3,000 feet of the facility boundary.

Figure 4-1.
Targa Midstream Services LLC
Mont Belvieu Area Map

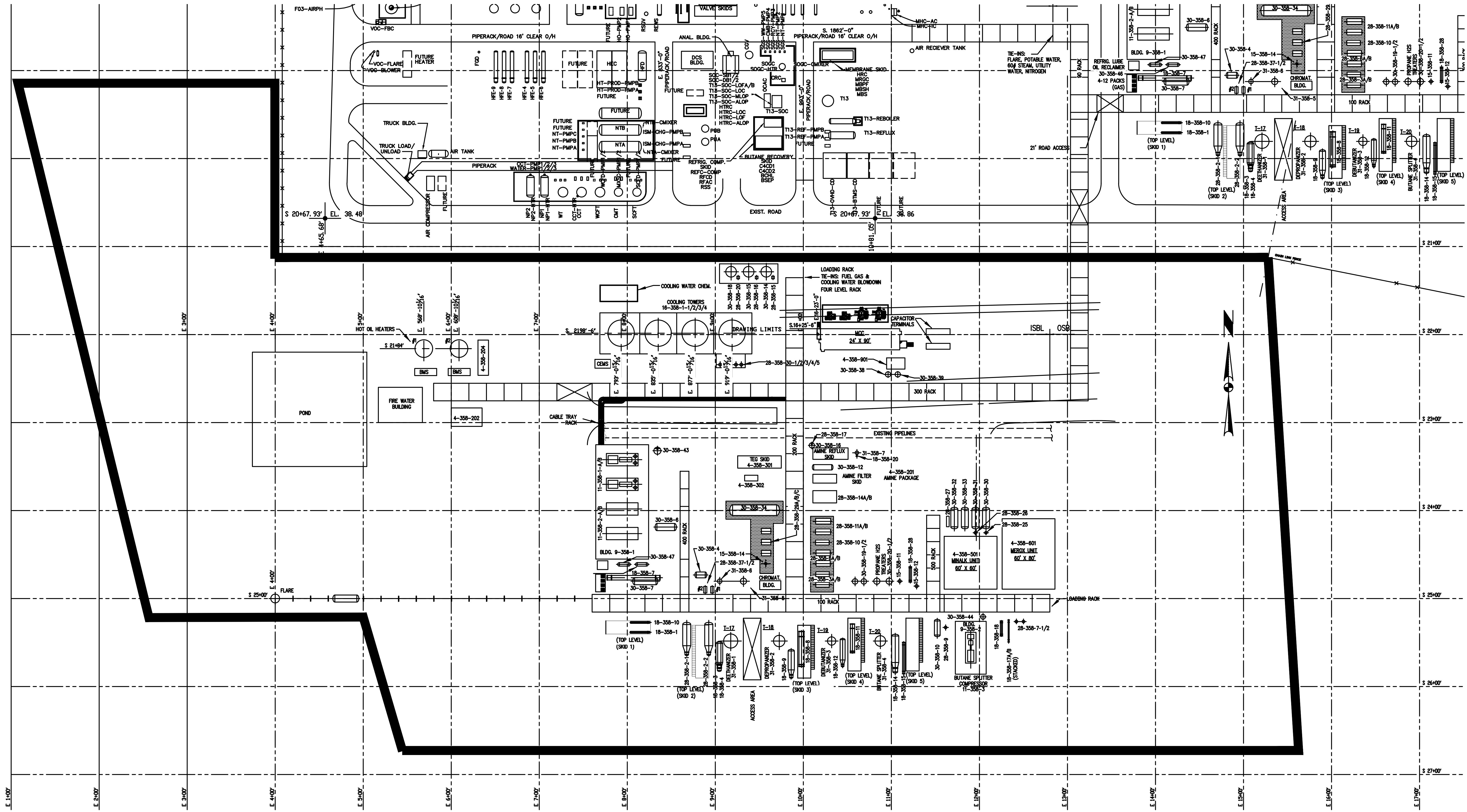


Legend

- Property Line
- Residential Areas
- Sensitive Receptors - Places of Worship

Reference UTM Coordinates are in NAD83.
Map image from Google Earth TM Mapping Service.

The following figure depicts the site plans for the proposed project at the Mont Belvieu Plant.



PIPERACK/ROAD 16' CLEAR O/H
TRUCK BLDG.
TRUCK LOAD/ UNLOAD
AIR TANK
PIPERACK
AIR COMPRESSOR
FUTURE HEATER
DCS BLDG.
ANAL. BLDG.
REFRIG. COMP. SKID
BUTANE RECOVERY
EXIST. ROAD
MEMBRANE SKID
AIR RECIEVER TANK
VALVE SKIDS
TIE-INS: FLARE, POTABLE WATER, 60# STEAM, UTILITY WATER, NITROGEN
REFRIG. LUBE OIL RECLAIMER
21' ROAD ACCESS
COOLING WATER CHEM.
COOLING TOWERS 16-358-1-1/2/3/4
DRAWING LIMITS
LOADING RACK
TIE-INS: FUEL GAS & COOLING WATER BLOWDOWN
FOUR LEVEL RACK
MCC 24' X 90'
CAPACITOR TERMINALS
ISBL
OSBL
HOT OIL HEATERS
POND
FIRE WATER BUILDING
CABLE TRAY RACK
300 RACK
200 RACK
EXISTING PIPELINES
TEG SKID 4-358-301
AMINE REFLUX SKID
AMINE FILTER SKID
AMINE PACKAGE
400 RACK
BLDG. 9-358-1
CHROMAT. BLDG.
100 RACK
500 RACK
MINALK UNIT 60' X 60'
MEROX UNIT 60' X 80'
FLARE
DEETHANIZER
DEPROPANIZER
DEBUTANIZER
BUTANE SPLITTER
BUTANE SPLITTER COMPRESSOR 11-358-3
ACCESS AREA
(TOP LEVEL)

6. PROCESS DESCRIPTION & PROCESS FLOW DIAGRAM

The Mont Belvieu Fractionator, a process unit at Mont Belvieu Plant, is designed to fractionate natural gas liquids into various products. With this project, Targa plans to build a new fractionation train (Train 5). The feed consists of mixed NGLs (which is a mixture of ethane, propane, butane, heavier hydrocarbons, carbon dioxide (CO_2), and small amounts of hydrogen sulfide (H_2S)). The feed is sent to the deethanizer to separate ethane. The overhead off the deethanizer will be treated in the amine unit to remove the non-hydrocarbon gases (CO_2 and H_2S). Then water is removed from the ethane in the TEG dehydration unit. The heavier fraction from the deethanizer is fed to the depropanizer to separate propane product. The heavier fraction of the depropanizer is further fed to the debutanizer to separate the mixed butane product from natural gasoline. The butane product is then sent through the deisobutanizer to separate normal and iso-butane. All the specification NGL products are transported from the fractionation plant by pipelines. Supporting utility operations include the installation of two new hot oil heaters and a cooling tower for heating and cooling of the process, respectively.

The following subsections further describe the processes, equipment, and emission points that are proposed to be constructed as part of the proposed Train 5 project. A process flow diagram showing the new sources is included at the end of this section.

6.1. AMINE UNIT

Amine Unit 4 (Facility Identification Number [FIN] AU-4) includes an absorber, regenerator, and flash drum. In the absorber, an amine solution absorbs CO_2 and H_2S from a fractionated ethane gas stream to produce a treated ethane stream with lower CO_2 content and no H_2S. These non-hydrocarbon contaminants (CO_2 and H_2S) are in solution with the rich amine solution. The rich amine is then routed to a regenerator that separates the non-hydrocarbon contaminants from the amine solution to produce regenerated (lean) amine that can be reused in the absorber. Emissions from the regenerator and flash drum are routed to the flare (Emission Point Number [EPN] FLR-5). Treated gas is sent to a new TEG dehydration unit for removal of moisture/water.

6.2. TEG DEHYDRATION UNIT

The TEG Dehydration Unit (FIN TEG-2) uses TEG to remove water or water vapor present in the ethane gas stream and includes a flash tank. Emissions from the glycol unit regenerator and flash tank are routed to the flare (EPN FLR-5).

6.3. HOT OIL HEATERS

Two new hot oil heaters are required as part of this project. The heaters (EPNs F5A and F5B) are natural gas-fired heaters with a higher heating value (HHV) design capacity of 144.45 million British thermal units per hour (MMBtu/hr) each. The new heaters are equipped with low-NO_x burners and selective catalytic reduction (SCR) systems.

6.4. COOLING TOWER

A new cooling tower is required to provide for the fractionation process cooling. Cooling Tower 9 (EPN FUG-CT-9) is a mechanically induced draft, counterflow cooling tower. The cooling tower is designed to recirculate 44,322 gallons per minute (gpm) water.

6.5. FUGITIVE COMPONENTS

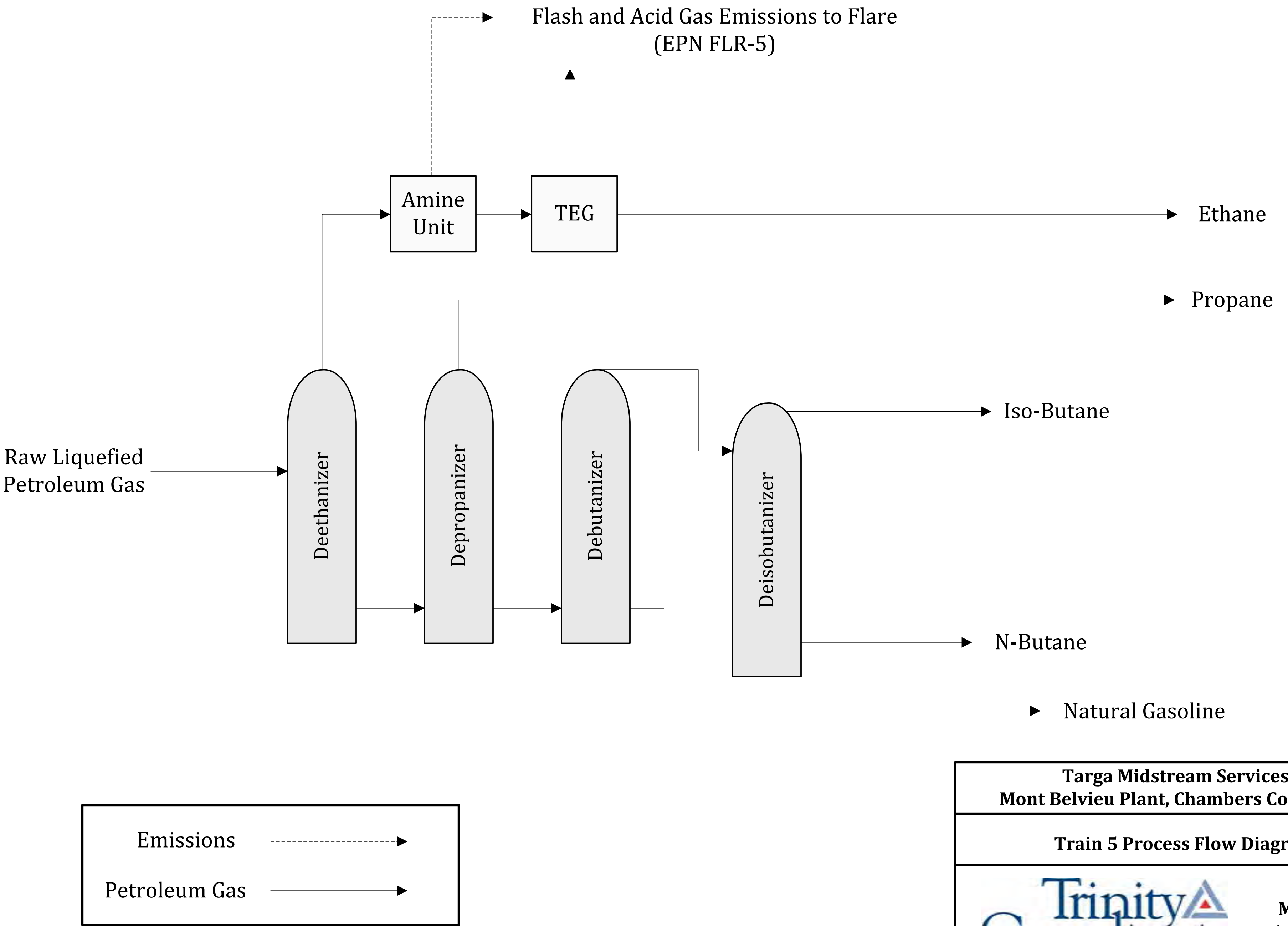
New fugitive emissions (EPN FUG-FRAC5) from piping and equipment associated with the proposed project are accounted for via the number of valves, flanges, and other connections.

6.6. ATMOSPHERIC STORAGE TANKS

Several small atmospheric storage tanks, including Ucarsol (EPN TK-2) and TEG tanks, will be added with this project. At room temperature, TEG has a vapor pressure of less than 0.01 mm Hg. Per TCEQ's 1996 guidance memo, emission calculations are not required for this tank.[4] Additionally, the other atmospheric storage tanks have both a low vapor pressure and low throughput. Therefore, based on engineering judgment, the emissions from these tanks are considered negligible. Emissions from the Ucarsol tank are discussed in Section 7.7 of this application.

[4] Texas Natural Resource Conservation Commission New Source Review Division interoffice memorandum, When should a compound be considered an air containment, dated September 19, 1996.

Figure 6.1 - Train 5 Process Flow Diagram



Targa Midstream Services LLC
Mont Belvieu Plant, Chambers County, Texas

Train 5 Process Flow Diagram

Trinity Consultants

March 2012
114401.0169

This section summarizes the criteria and hazardous air pollutant (HAP) emission calculation methodologies and provides emission calculations for the emission sources for the proposed new Fractionation Train 5. GHG emissions are not addressed in this permit application nor are they quantified in this section.

Detailed emission calculation spreadsheets, including example calculations, are included at the end of this section. These emission estimates reflect the emission limits chosen as BACT in Section 11.

The following emission units are included in the emission calculations provided at the end of this section:

- Amine unit (FIN AU-4, EPN FLR-5);
- TEG dehydration unit (FIN TEG-2, EPN FLR-5);
- Cooling tower (EPN FUG-CT-9);
- Hot oil heaters (EPNs F5A and F5B);
- Ucarsol Storage Tank (EPN TK-2);
- Fugitive emissions from piping components (EPN FUG-FRAC5);
- Maintenance emissions to the flare (FIN Maintenance, EPN FLR-5);
- Startup emissions to the flare (FIN Startup, EPN FLR-5);
- Shutdown emissions to the flare (FIN Shutdown, EPN FLR-5);
- Maintenance emissions to the atmosphere (FIN Maintenance, EPN Maintenance); and
- Shutdown emissions to the atmosphere (FIN Shutdown, EPN Shutdown).

7.1. HEATERS

Two new hot oil heaters are proposed as part of this project. The heaters (EPNs F5A and F5B) are natural gas-fired heaters with a HHV design capacity of 144.45 MMBtu/hr each. The new heaters are equipped with low-NO_x burners and SCR systems.

Emissions factors for the heaters for NO_x, carbon dioxide (CO), particulate matter (PM), particulate matter with aerodynamic diameter less than 10 micrometers (PM_{10}), and particulate matter less than 2.5 micrometers ($PM_{2.5}$) are based on manufacturer guarantees; VOC and sulfur dioxide (SO_2) emission factors are obtained from U.S. EPA AP-42 Section 1.4, Table 1.4-2.[5] Ammonia (NH_3) emissions are estimated based on a manufacturer guaranteed ammonia slip rate of 7 parts per million by volume on a dry basis (ppmvd).

The emission factors for VOC and SO_2 obtained from AP-42 Table 1.4-2 are converted from pounds per million standard cubic feet (lb/MMscf) of natural gas fired to lb/MMBtu heat input by dividing the emission factor by the average natural gas heating value of 1,020 Btu/scf, per AP-42 Table 1.4-2, footnote a. The emission factors also were converted to the site-specific natural gas heating value by multiplying by the ratio of the site-specific heating value to the average heating value of 1,020 Btu/scf. An example conversion calculation follows:

[5] U.S. EPA AP-42 Section 1.4, Natural Gas Combustion from External Combustion Sources (July 1998).

$$\text{Emission Factor}\left(\frac{\text{lb}}{\text{MMBtu}}\right) = \frac{\text{AP-42 Emission Factor}\left(\frac{\text{lb}}{\text{MMscf}}\right)}{1{,}020\ \left(\frac{\text{Btu}}{\text{scf}}\right)} \times \frac{\text{Site-Specific Heating Value}\ \left(\frac{\text{Btu}}{\text{scf}}\right)}{1{,}020\ \left(\frac{\text{Btu}}{\text{scf}}\right)}$$

Hourly emission rates are based on the maximum heat input rating (MMBtu/hr) for each heater. The following is an example calculation for hourly NO_X, CO, VOC, PM/PM_{10}/$PM_{2.5}$, and SO_2 emission rates from the heaters:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Heat Input Rating}\left(\frac{\text{MMBtu}}{\text{hr}}\right) \times \text{Emission Factor}\left(\frac{\text{lb}}{\text{MMBtu}}\right)$$

The following is an example calculation for hourly ammonia emission rates from the heaters:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right)$$
$$= \text{Heat Input Rating}\left(\frac{\text{MMBtu}}{\text{hr}}\right) \times \text{Ammonia Slip Rate(ppmvd)} \times \text{Molecular Weight}\left(\frac{\text{lb}}{\text{lb} - \text{mol}}\right)$$
$$\times \left(\frac{2.69 \times 10^{-9}\ \text{lb} - \text{mol}}{\text{scf}}\right) \times F_d\left(\frac{8{,}710\ \text{dscf}}{\text{MMBtu}}\right) \times \left(\frac{20.9\%}{20.9\% - O_2\%}\right)$$

Annual emission rates are based on maximum operation equivalent to 8,760 hrs/yr using the following equation:

$$\text{Annual Emission Rate (tpy)} = \text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Hours of Operation}\left(\frac{\text{hr}}{\text{yr}}\right) \times \left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right)$$

7.2. AMINE TREATER

Amine Unit 4 (FIN AU-4) includes an absorber, regenerator, and flash drum. In the absorber, an amine solution absorbs CO_2 from a fractionated ethane gas stream to produce a treated ethane stream with lower CO_2 and no H_2S content and a rich amine solution. The rich amine is then routed to a regenerator to produce regenerated (lean) amine that can be reused in the absorber. VOC and H_2S emissions from the regenerator and flash drum will be routed to the flare (EPN FLR-5). Details for the calculation of flare combustion emissions are provided in Section 7.5.

7.3. GLYCOL DEHYDRATOR

Emissions from the proposed TEG dehydration unit (FIN TEG-2) consist of VOCs from the regenerator and flash tank. In order to calculate emissions from the TEG dehydration unit, the GRI-GLYCalc program is used.[6] The TEG dehydration unit is equipped with a flash tank, and no stripping gas is used. The flash tank and the regenerator off gas will be routed to the flare (EPN FLR-5). Details for the calculation of flare combustion emissions are provided in Section 7.5.

[6] GRI-GLYCalc™ Version 4.0.

7.4. MSS ACTIVITITES

The proposed project has a variety of maintenance, startup, and shutdown (MSS) activities. Both maintenance activities and shutdown activities can be vented to the atmosphere or sent to the flare. Startup activities are always routed to the flare. Controlled emissions from MSS activities routed to the flare are discussed in Section 7.5. Uncontrolled emissions from MSS activities vented to atmosphere are calculated using the following equations for gaseous and liquid activities, respectively:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Gas Volume per Event}\left(\frac{\text{scf}}{\text{event}}\right) \times \frac{1}{\text{Event Duration}\left(\frac{\text{hr}}{\text{event}}\right)} \times \text{Component Vapor Mass Fraction} \times \text{Vapor Density}\left(\frac{\text{lb}}{\text{scf}}\right)$$

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Liquid Volume per Event}\left(\frac{\text{scf}}{\text{event}}\right) \times \frac{1}{\text{Event Duration}\left(\frac{\text{hr}}{\text{event}}\right)} \times \text{Component Liquid Mass Fraction} \times \text{Liquid Density}\left(\frac{\text{lb}}{\text{scf}}\right)$$

Annual VOC emission rates from uncontrolled MSS activities are estimated based on hourly emission rates, event frequency, and event duration, using the following equation:

$$\text{Annual Emission Rate (tpy)} = \text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Event Frequency}\left(\frac{\text{event}}{\text{yr}}\right) \times \text{Event Duration}\left(\frac{\text{hr}}{\text{event}}\right) \times \left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right)$$

7.5. FLARE

The flare (EPN FLR-5) will be used to destroy the off-gas produced during emergency situations, amine venting, TEG dehydrator venting, and MSS activities. Emissions from emergency events are not included in this application since they are non-routine.

Emissions of NO_x, CO, VOC, SO_2, H_2S, and HAPs from the flare will result from the combustion of pipeline quality natural gas in the pilot and as supplemental fuel, and the combustion of gas vented to the flare. The supplement fuel will be mixed with amine and dehydrator waste gases to maintain heat content of waste gas greater than 300 Btu/scf as required for compliance with Title 40 of the Code of Federal Regulations (40 CFR) §60.18.

NO_X and CO Hourly Emissions

Emission factors for NO_X and CO are obtained from the TCEQ guidance for flares and vapor oxidizers, Table 4.[7] The emission rates are based on the hourly gas stream heat inputs using the following equation:

$$\text{Hourly Gas Stream Heat Input}\left(\frac{\text{MMBtu}}{\text{hr}}\right) = \text{Hourly Flowrate}\left(\frac{\text{scf}}{\text{hr}}\right) \times \text{Gas Stream Heat Value}\left(\frac{\text{Btu}}{\text{scf}}\right) \times \left(\frac{\text{MMBtu}}{10^6\ \text{Btu}}\right)$$

The following equation is used to estimate hourly NO_X and CO emission rates from the combustion of fuel gas in the pilot, supplemental fuel gas, vent gas routed to the flare from the amine unit and TEG dehydrator, and vent gas routed to the flare during MSS activities:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Flare Emission Factor}\left(\frac{\text{lb}}{\text{MMBtu}}\right) \times \text{Hourly Gas Stream Heat Input}\left(\frac{\text{MMBtu}}{\text{hr}}\right)$$

VOC and HAP Hourly Emissions

VOC and HAP emissions occur from the combustion of fuel gas in the pilot, supplemental fuel gas, vent gas routed to the flare from the amine unit and TEG dehydrator, and vent gas routed to the flare during MSS activities.

Uncontrolled emissions from the fuel gas and supplemental gas are calculated based on the composition of the gas and flowrate to the flare. The following is an example calculation:

$$\text{Uncontrolled Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Maximum Hourly Flowrate}\left(\frac{\text{scf}}{\text{hr}}\right) \times \text{Composition (mol \%)} \times \text{Molecular Weight}\left(\frac{\text{lb}}{\text{lb}-\text{mol}}\right) \times \left(\frac{\text{lb}-\text{mol}}{379.5\ \text{scf}}\right)$$

Uncontrolled emissions from the amine unit are obtained from similar operations at the facility. The following equation is used to estimate uncontrolled hourly VOC and HAP emission rates from the amine unit:

$$\text{Uncontrolled Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Output Stream Data}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Composition (\%)}$$

Uncontrolled emissions from the TEG dehydration unit are obtained from the GRI-GLYCalc output file.[8] The input and output from the GLYCalc run are provided in Appendix A of this application.

$$\text{Uncontrolled Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{GLYCalc Output Data}\left(\frac{\text{lb}}{\text{hr}}\right)$$

Uncontrolled emissions from the MSS activities are calculated as discussed in Section 7.4 of this permit application.

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[7] TCEQ Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers (October 2000).

[8] GRI-GLYCalc™ Version 4.0.

Controlled hourly emission rates of VOC and HAP, as controlled by the flare, are estimated using the inlet to flare as calculated above and the guaranteed Destruction Rate Efficiency (DRE). The following equation is used to estimate hourly VOC and HAP emission rates from the controlled streams:

$$\text{Controlled Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Uncontrolled Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times [1 - \text{DRE }(\%)/100]$$

<u>H_2S Emissions</u>

The inlet stream to the processing train contains small amounts of H_2S. Targa has conservatively estimated that all H_2S at the inlet is removed by the amine treater and vented from the acid gas stream, which is routed to the flare. Uncontrolled H_2S concentration at the inlet is 0.03 ppmw. The hourly H_2S emission rate is conservatively based on 200% of the daily average concentration. The following equation is used to estimate the controlled hourly emissions from the flare:

$$\text{Controlled Hourly } H_2S \text{ Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = 2 \times H_2S\text{ Content(ppmw)} \times \left(\frac{1}{1{,}000{,}000}\right) \times \text{Inlet Volume Flow Rate}\left(\frac{\text{bbl}}{\text{day}}\right) \times \frac{42\text{ gal}}{\text{bbl}} \times \frac{8.34\text{ lb}}{\text{gal}} \times \text{Specific Gravity} \times \frac{1\text{ day}}{24\text{ hr}} \times [1 - \text{DRE }(\%)/100]$$

<u>SO_2 Emissions</u>

SO_2 emissions are based on the conversion of sulfur during the destruction of inlet H_2S using the destruction rate efficiency of the flare, the H_2S concentration, and the ratio of the molecular weights of SO_2 and H_2S. The hourly SO_2 emission rate is conservatively based on 200% of the daily average H_2S concentration. The following equation is used to estimate hourly SO_2 emission rates from the controlled stream:

$$\text{Controlled Hourly } SO_2 \text{ Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = 2 \times \text{DRE }(\%)/100 \times H_2S\text{ Content (ppmw)} \times \left(\frac{1}{1{,}000{,}000}\right) \times \text{Inlet Volume Flow Rate}\left(\frac{\text{bbl}}{\text{day}}\right) \times \frac{42\text{ gal}}{\text{bbl}} \times \frac{8.34\text{ lb}}{\text{gal}} \times \text{Specific Gravity} \times \frac{1\text{ day}}{24\text{ hr}} \times \left(\frac{SO_2\text{ Molecular Weight}}{H_2S\text{ Molecular Weight}}\right)$$

<u>Annual Emissions</u>

Annual emission rates from the combustion of fuel gas in the pilot, supplemental fuel gas, and vent gas from the amine and dehydrator streams are based on the hourly emission factors and the operating hours of the flare, as shown in the following equation:

$$\text{Annual Emissions (tpy)} = \text{Controlled Hourly Emissions}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Hours of Operation}\left(\frac{\text{hrs}}{\text{yr}}\right) \times \left(\frac{\text{ton}}{2{,}000\text{ lb}}\right)$$

Annual H_2S and SO_2 emission rates do not include the conservative safety factor of 200%.

Annual VOC emission rates from all MSS activities are estimated based on hourly emission rates, event frequency, and event duration, using the following equation:

Annual Emission Rate (tpy)

$$= \text{Controlled Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Event Frequency}\left(\frac{\text{event}}{\text{yr}}\right) \times \text{Event Duration}\left(\frac{\text{hr}}{\text{event}}\right) \times \left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right)$$

7.6. COOLING TOWER

Emissions from the cooling tower (EPN FUG-CT-9) consist of PM, $PM_{10}/PM_{2.5}$, and VOC.

Hourly PM emissions are calculated based on the unit's design water circulation rate, drift rate, and the total dissolved solids (TDS) content using the following equation:

Hourly Emission Rate (lb/hr)

$$= \text{Water Circulation Rate}\left(\frac{\text{gal}}{\text{min}}\right) \times \text{Drift Rate (\%)} \times \text{TDS (ppmv)} \times \left(\frac{8.34\ \text{lb}}{\text{gal}}\right) \times \left(\frac{60\ \text{min}}{\text{hr}}\right)$$

$PM_{10}/PM_{2.5}$ emissions are based on a portion of the PM emissions. It is estimated that 30% of PM emissions are $PM_{10}/PM_{2.5}$ emissions based on Reisman and Frisbie's *Calculating Realistic PM_{10} Emissions from Cooling Towers*.[9]

Hourly VOC emissions are based on the unit's total hydrocarbon (THC) leak rate and the water circulation rate using the following equation:

Hourly Emission Rate (lb/hr)

$$= \text{Water Circulation Rate}\left(\frac{\text{gal}}{\text{min}}\right) \times \text{VOC Content (\%)} \times \text{THC (ppmv)} \times \left(\frac{8.34\ \text{lb}}{\text{gal}}\right) \times \left(\frac{60\ \text{min}}{\text{hr}}\right)$$

Annual emissions for PM, $PM_{10}/PM_{2.5}$, and VOC are calculated using the hourly emission rate and the annual operating hours:

$$\text{Annual Emissions (tpy)} = \text{Hourly Emissions}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Hours of Operation}\left(\frac{\text{hrs}}{\text{yr}}\right) \times \left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right)$$

7.7. UCARSOL STORAGE TANK

The Ucarsol tank (EPN TK-2) has both a low vapor pressure (4.6 mm Hg) and low throughput. Based on engineering judgment, the emissions from this tank are considered negligible and represented as less than 0.01 lb/hr and 0.01 tpy in this application.

[9] Joel Reisman and Gordon Frisbie, Greystone Environmental Consultants, Inc., Calculating Realistic PM_{10} Emissions from Cooling Towers, Abstract No. 216.

7.8. EQUIPMENT LEAK FUGITIVES

Process fugitive emissions of VOC and HAP result from leaking components such as valves and flanges (EPN FUG-FRAC5).

Emissions from fugitive equipment leaks are calculated using fugitive component counts for the proposed project, the VOC content of each stream for which component counts are placed in service and emission factors for each component type taken from the TCEQ Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives.[10] Targa has selected the 28 VHP Monitoring Program, and these control efficiencies are applied to the equipment leak fugitive calculations. In addition, Targa will monitor flanges quarterly using an organic vapor analyzer (OVA) at the same leak definition for valves; therefore, the 97% control efficiency is used for flanges.

Hourly emissions of VOC from the fugitive components (i.e., valves and flanges) are estimated using TCEQ emission factors, component counts, and the VOC content of each stream. The following equation is used to estimate hourly VOC emissions:

$$\begin{aligned}&\text{Hourly Emission Rate (lb/hr)}\\&\quad= \text{TCEQ Emission Factor}\left(\frac{\text{lb}}{\text{hr-comp}}\right)\times \text{Number of Components (\# comp)}\\&\quad\times \text{VOC Weight Percent (\% wt)} \times (1 - \text{28 VHP Control Factor(\%)}/100)\end{aligned}$$

Speciated VOC and HAP emissions from the fugitive components are estimated based on the total VOC emissions as estimated above and the speciated gas analysis for each stream. The following equation is used to estimate speciated VOC and HAP emissions for each compound in the stream:

$$\begin{aligned}&\text{Speciated Hourly Emission Rate (lb/hr)}\\&\quad= \text{TCEQ Emission Factor}\left(\frac{\text{lb}}{\text{hr-comp}}\right)\times \text{Number of Components (\# comp)}\\&\quad\times \text{Compound Weight Percent (\% wt)} \times (1 - \text{28 VHP Control Factor(\%)}/100)\end{aligned}$$

Annual emissions are estimated based on hourly emissions rates and maximum operation equivalent to 8,760 hrs/yr, as shown in the following equation:

$$\text{Annual Emission Rate (tpy)} = \text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right)\times \text{Hours of Operation}\left(\frac{\text{hr}}{\text{yr}}\right)\times\left(\frac{\text{ton}}{\text{2,000 lb}}\right)$$

[10] TCEQ, Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000.

Targa Midstream Services LLC - Mont Belvieu Plant Train 5
Summary of Site-Wide Emissions

Summary of Hourly Emissions

	Hourly Emissions (lb/hr)													
Criteria Pollutants	**Controlled TEG-2 Emissions (FLR-5)**	**Controlled AU-4 Emissions (FLR-5)**	**Hot Oil Heater (F5A)**	**Hot Oil Heater (F5B)**	**Fugitives (FUG-FRAC5)**	**Cooling Tower 9 (FUG-CT-9)**	**Ucarsol Storage Tank (TK-2)[1]**	**Flare Pilot & Supplemental Fuel (FLR-5)**	**Controlled Maintenance Emissions (FLR-5) [2]**	**Maintenance Emissions to Atmosphere (Maintenance)**	**Controlled Startup Emissions (FLR-5)**	**Controlled Shutdown Emissions (FLR-5) [3]**	**Shutdown Emissions to Atmosphere (Shutdown)**	**Total [4]**
CO	0.38	1.28	5.34	5.34	-	-	-	3.76	0.47	-	2.45	4.69	-	16.58
NO_x	0.04	0.15	0.72	0.72	-	-	-	0.46	0.23	-	1.23	2.35	-	2.35
VOC	0.04	0.01	0.09	0.09	0.31	1.63	<0.01	0.34	13.96	1.15	48.01	43.68	10.52	48.01
PM	-	-	0.58	0.58	-	0.55	-	-	-	-	-	-	-	1.71
PM_{10}	-	-	0.58	0.58	-	0.17	-	-	-	-	-	-	-	1.32
$PM_{2.5}$	-	-	0.58	0.58	-	0.17	-	-	-	-	-	-	-	1.32
SO_2	-	0.09	0.08	0.08	-	-	-	-	-	-	-	-	-	0.25
HAPs	-	-	-	-	5.04E-03	1.15E-05	0.00E+00	0.13	0.26	9.64E-04	0.21	0.65	0.09	0.65
Speciated Constituents														
Ammonia	-	-	0.46	0.46	-	-	-	-	-	-	-	-	-	0.91
Hydrogen Sulfide	-	9.32E-04	-	-	-	-	-	-	-	-	-	-	-	9.32E-04
Ucarsol AP-810	-	3.04E-05	-	-	-	-	<0.01	-	-	-	-	-	-	0.01
Propane	0.04	0.01	0.09	0.09	0.10	0.87	-	0.06	7.70	0.57	11.75	11.75	1.38	11.75
i-Butane	-	-	-	-	0.07	0.39	-	0.05	6.00	0.49	11.56	11.56	2.02	11.56
n-Butane	-	-	-	-	0.09	0.37	-	0.04	3.86	0.05	15.61	15.51	2.85	15.61
i-Pentane	-	-	-	-	0.02	1.94E-03	-	0.04	1.36	0.02	4.60	3.45	2.12	4.60
n-Pentane	-	-	-	-	0.01	5.04E-05	-	0.02	1.20	0.01	3.03	2.99	1.40	3.03
n-Hexane	-	-	-	-	3.62E-03	1.00E-12	-	0.13	0.26	9.64E-04	0.21	0.65	0.09	0.65
n-Heptane	-	-	-	-	0.02	-	-	-	1.59	6.77E-03	1.24	3.94	0.67	3.94
COS	-	-	-	-	2.41E-06	1.15E-05	-	-	-	-	-	-	-	1.39E-05
Methyl Mercaptan	-	-	-	-	3.70E-05	1.69E-04	-	-	-	-	-	-	-	2.06E-04
Ethyl Mercaptan	-	-	-	-	1.99E-05	4.31E-05	-	-	-	-	-	-	-	6.30E-05
Dimethyl Sulfide	-	-	-	-	3.83E-06	7.26E-06	-	-	-	-	-	-	-	1.11E-05
n-Propyl Mercaptan	-	-	-	-	1.89E-05	2.98E-12	-	-	-	-	-	-	-	1.89E-05
n-Butyl Mercaptan	-	-	-	-	9.35E-07	-	-	-	-	-	-	-	-	9.35E-07
Dimethyl Disulfide	-	-	-	-	8.11E-07	-	-	-	-	-	-	-	-	8.11E-07
Diethyl Disulfide	-	-	-	-	1.14E-06	-	-	-	-	-	-	-	-	1.14E-06
Benzene	-	-	-	-	4.59E-04	2.22E-14	-	-	-	-	-	-	-	4.59E-04
Toluene	-	-	-	-	4.86E-04	-	-	-	-	-	-	-	-	4.86E-04
Ethylbenzene	-	-	-	-	3.17E-04	-	-	-	-	-	-	-	-	3.17E-04
m-Xylene	-	-	-	-	1.54E-04	-	-	-	-	-	-	-	-	1.54E-04

[1] Based on the low vapor pressure and the low throughput of the Ucarsol storage tank, emissions are assumed negligible and represented as less than 0.01 lb/hr. For total emission calculations, emissions are conservatively assumed to be 0.01 lb/hr.

[2] Controlled maintenance of liquid releases and controlled maintenance of vapor releases do not occur at the same time; therefore, the hourly emissions are based on the maximum of either liquid or vapor emissions.

[3] Controlled shutdown of liquid releases and controlled shutdown of vapor releases do not occur at the same time; therefore, the hourly emissions are based on the maximum of either liquid or vapor emissions.

[4] The total hourly emissions are calculated based on the maximum emissions rate between maintenance and normal operations, startup, and shutdown (controlled and to atmosphere). Maintenance emissions occur at the same time as normal operation. Maintenance emissions to the flare do not occur at the same time as maintenance emissions to the atmosphere. Startup emissions do not occur during normal operation or maintenance. Shutdown emissions do not occur during normal operation or maintenance. Startup and shutdown emissions do not occur at the same time. Controlled shutdown of liquid releases, controlled shutdown of vapor releases, and uncontrolled shutdown emissions do not occur at the same time.

Maximum hourly emissions are taken from the following operating scenarios:

(1) TEG-2 to FLR-5, AU-4 to FLR-5, F5A, F5B, Frac5, Cooling Tower 9, Ucarsol Tank, Pilot & Supplemental Fuel to FLR-5, Maintenance to FLR-5
(2) TEG-2 to FLR-5, AU-4 to FLR-5, F5A, F5B, Frac5, Cooling Tower 9, Ucarsol Tank, Pilot & Supplemental Fuel to FLR-5, Maintenance to Atmosphere
(3) Startup to FLR-5
(4) Shutdown to FLR-5
(5) Shutdown to Atmosphere

Summary of Annual Emissions

	Annual Emissions (tpy)													
Criteria Pollutants	**Controlled TEG-2 Emissions (FLR-5)**	**Controlled AU-4 Emissions (FLR-5)**	**Hot Oil Heater (F5A)**	**Hot Oil Heater (F5B)**	**Fugitives (FUG-FRAC5)**	**Cooling Tower 9 (FUG-CT-9)**	**Ucarsol Storage Tank (TK-2)[1]**	**Flare Pilot & Supplemental Fuel (FLR-5)**	**Controlled Maintenance Emissions (FLR-5)**	**Maintenance Emissions to Atmosphere (Maintenance)**	**Controlled Startup Emissions (FLR-5)**	**Controlled Shutdown Emissions (FLR-5)**	**Shutdown Emissions to Atmosphere (Shutdown)**	**Total[2]**
CO	1.68	5.59	23.41	23.41	-	-	-	16.49	0.01	-	0.05	0.05	-	70.69
NO_x	0.20	0.65	3.16	3.16	-	-	-	2.02	6.80E-03	-	0.03	0.03	-	9.25
VOC	0.17	0.06	0.38	0.38	1.38	7.13	<0.01	1.49	0.63	0.01	0.51	0.99	0.07	13.20
PM	-	-	2.53	2.53	-	2.43	-	-	-	-	-	-	-	7.49
PM_{10}	-	-	2.53	2.53	-	0.73	-	-	-	-	-	-	-	5.79
$PM_{2.5}$	-	-	2.53	2.53	-	0.73	-	-	-	-	-	-	-	5.79
SO_2	-	0.19	0.37	0.37	-	-	-	-	-	-	-	-	-	0.93
HAPs	-	-	-	-	0.02	5.05E-05	0.00E+00	0.58	9.53E-03	5.39E-05	1.26E-03	0.01	5.38E-04	0.63
Speciated Constituents														
Ammonia	-	-	1.99	1.99	-	-	-	-	-	-	-	-	-	3.99
Hydrogen Sulfide	-	2.04E-03	-	-	-	-	-	-	-	-	-	-	-	2.04E-03
Ucarsol AP-810	-	1.33E-04	-	-	-	-	<0.01	-	-	-	-	-	-	0.01
Propane	0.17	0.06	0.38	0.38	0.43	3.82	-	0.25	0.18	3.94E-03	0.20	0.27	0.01	6.14
i-Butane	-	-	-	-	0.32	1.69	-	0.21	0.09	1.86E-03	0.13	0.24	0.02	2.69
n-Butane	-	-	-	-	0.37	1.61	-	0.19	0.20	3.08E-03	0.14	0.29	0.02	2.83
i-Pentane	-	-	-	-	0.08	0.01	-	0.17	0.05	1.18E-03	0.02	0.07	0.01	0.41
n-Pentane	-	-	-	-	0.07	2.21E-04	-	0.09	0.04	7.77E-04	0.02	0.05	0.01	0.27
n-Hexane	-	-	-	-	0.02	4.38E-12	-	0.58	0.01	5.39E-05	1.26E-03	0.01	5.38E-04	0.62
n-Heptane	-	-	-	-	0.09	-	-	-	0.06	3.78E-04	0.01	0.06	3.78E-03	0.22
COS	-	-	-	-	1.06E-05	5.05E-05	-	-	-	-	-	-	-	6.10E-05
Methyl Mercaptan	-	-	-	-	1.62E-04	7.38E-04	-	-	-	-	-	-	-	9.00E-04
Ethyl Mercaptan	-	-	-	-	8.72E-05	1.89E-04	-	-	-	-	-	-	-	2.76E-04
Dimethyl Sulfide	-	-	-	-	1.68E-05	3.18E-05	-	-	-	-	-	-	-	4.86E-05
n-Propyl Mercaptan	-	-	-	-	8.29E-05	1.30E-11	-	-	-	-	-	-	-	8.29E-05
n-Butyl Mercaptan	-	-	-	-	4.10E-06	-	-	-	-	-	-	-	-	4.10E-06
Dimethyl Disulfide	-	-	-	-	3.55E-06	-	-	-	-	-	-	-	-	3.55E-06
Diethyl Disulfide	-	-	-	-	5.00E-06	-	-	-	-	-	-	-	-	5.00E-06
Benzene	-	-	-	-	2.01E-03	9.72E-14	-	-	-	-	-	-	-	2.01E-03
Toluene	-	-	-	-	2.13E-03	-	-	-	-	-	-	-	-	2.13E-03
Ethylbenzene	-	-	-	-	1.39E-03	-	-	-	-	-	-	-	-	1.39E-03
m-Xylene	-	-	-	-	6.75E-04	-	-	-	-	-	-	-	-	6.75E-04

[1] Based on the low vapor pressure and the low throughput of the Ucarsol storage tank, emissions are assumed negligible and represented as less than 0.01 tpy. For total emission calculations, emissions are conservatively assumed to be 0.01

[2] The total annual emissions is calculated based on the emissions rate of annual maintenance and normal operations, startup, and shutdown (controlled and to atmosphere). Startup emissions and shutdown emissions occur once annually.

Total Annual Emissions (tpy) = Annual Emissions of Maintenance and Normal Operations + Annual Emissions of Startup Controlled to FLR-5 + Annual Emissions of Shutdown Controlled Emissions to FLR-5 + Shutdown Uncontrolled Emissions to Atmosphere

Targa Midstream Services LLC - Mont Belvieu Plant
TEG Dehydration Unit Emissions

FLR-5 Emission Factors [1]

Units	CO	NO_x
lb/MMBtu	0.5496	0.0641
ppmw	-	-

[1] Flare Emissions factors are from TCEQ Air Permits Division, *Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers,* RG-109 (Draft), October 2000, Table 4 (other, low Btu).

Controlled Hydrocarbon Regenerator Emissions [1, 2]

Component	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
Methane	0.0004	0.0015
Ethane	0.2819	1.2346
Propane	0.0140	0.0612
Total VOC Emissions	0.0140	0.0612

[1] Emissions from GRI-GLYCalc 4.0.
[2] Emissions are routed to FLR-5 with a control efficiency of 99% for compounds with up to three carbon atoms, per TCEQ flare guidance.

Controlled Flash Gas Hydrocarbon Emissions [1, 2]

Component	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
Methane	0.0052	0.0227
Ethane	1.1306	4.9520
Propane	0.0239	0.1046
Total VOC Emissions	0.0239	0.1046

[1] Emissions from GRI-GLYCalc 4.0.
2 Emissions are routed to FLR-5 with a control efficiency of 99% for compounds with up to three carbon atoms, per TCEQ flare guidance.

Targa Midstream Services LLC - Mont Belvieu Plant
TEG Dehydration Unit Emissions

Speciated Gas Heating Rate

Speciated Gas	Higher Heating Value (Btu/lb)	Speciated Gas Percentage (%)[1] Regenerator Overheads	Speciated Gas Percentage (%)[1] Flash Gas	Gas Heating Rate (MMBtu/hr)[2] Uncontrolled Regenerator Overheads	Gas Heating Rate (MMBtu/hr)[2] Uncontrolled Flash Gas
Methane	23,900	7.44E-03	0.84	9.56E-04	0.01
Ethane	22,400	3.17	97.50	0.63	0.01
Propane	21,700	0.11	1.40	0.03	0.01
			Total	0.66	0.04

[1] Speciation for streams routed to the flare obtained from GRI-GLYCalc 4.0.
[2] Speciated Uncontrolled Gas Heating Rate (MMBtu/hr) = Controlled Gas Mass Flow Rate (lb/hr) / (1-Flare Control Efficiency (%)) x Higher Heating Value (Btu/lb) x 1 MMBtu / 1,000,000 Btu

Design Specifications

Parameter	Units	Regenerator Overheads	Flash Gas Emissions
Annual Hours of Operation	hr/yr	8,760	8,760
Flare Destruction Efficiency for C1-C3[2]	%	99	99

[1] Obtained from GRI-GLYCalc 4.0.
[2] Per TCEQ Air Permits Division, *Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers*, RG-109 (Draft), October 2000.

FLR-5 Combustion Emissions from TEG-2

FIN	EPN	Gas Stream	Gas Volume Flow[1] scf/hr	Dry Volume Flow[2,3,4] dscf/hr	Hourly Emissions[5] (lb/hr) NO_x	Hourly Emissions[5] (lb/hr) CO	Hourly Emissions[5] (lb/hr) VOC[6]	Annual Emissions[7] (tpy) NO_x	Annual Emissions[7] (tpy) CO	Annual Emissions[7] (tpy) VOC[6]
TEG-2	FLR-5	Regenerator Overheads	11,300	372.90	0.04	0.36	0.01	0.19	1.60	0.06
		Flash Gas	1,460	1,457.78	2.27E-03	0.02	0.02	9.93E-03	0.09	0.10
		Total			0.04	0.38	0.04	0.20	1.68	0.17

[1] Gas flow rate for streams routed to flare obtained from GRI-GLYCalc 4.0
[2] Water content in the flash gas emissions stream is 0.152 Vol %.
[3] Water content in the regenerator overheads stream is 96.7 Vol %.
[4] Dry Gas Volume Flow (dscf/hr) = Gas Volume Flow (scf/hr) - [Gas Volume Flow (scf/hr) x (Water Content (Vol %) / 100)]

Flash Tank Dry Gas Volume Flow (dscf/hr) = 1460 scf/hr - (1460 scf/hr x 0.152 /100) = 1,457.78 dscf/hr

[5] Hourly Emissions of NO_x or CO (lb/hr) = Emission Factor (lb/MMBtu) x Gas Heating Rate (MMBtu/hr)

$$\text{Flash Tank Hourly Emissions of } NO_x \text{ (lb/hr)} = \frac{0.064 \text{ lb}}{\text{MMBtu}} \times \frac{3.54\text{E-02 MMBtu}}{\text{hr}} = 2.27\text{E-03 lb/hr}$$

[6] Emissions from GRI-GLYCalc 4.0.
[7] Annual Emissions (tpy) = Hourly Emissions (lb/hr) x 8,760 (hr/yr) x 1 ton / 2,000 lb

$$\text{Flash Tank Annual Emissions of } NO_x \text{ (tpy)} = \frac{2.27\text{E-03 lb}}{\text{hr}} \times \frac{8760 \text{ hr}}{\text{yr}} \times \frac{1 \text{ ton}}{2{,}000 \text{ lb}} = 0.01 \text{ tpy}$$

Targa Midstream Services LLC - Mont Belvieu Plant
Amine Unit Emissions Calculations

FLR-5 Emission Factors [1]

Units	CO	NO_x	H_2S
lb/MMBtu	0.5496	0.0641	--
ppmw	--	--	0.03

[1] Flare NO_x and CO emissions factors are from TCEQ Air Permits Division, *Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers,* RG-109 (Draft), October 2000, Table 4 (other, low Btu).

Speciated Gas Heating Rate

Speciated Gas	Higher Heating Value (Btu/lb)	Speciated Gas Percentage [1] (%)		Gas Heating Rate (MMBtu/hr)	
		Flash Gas	Acid Gas	Flash Gas [2]	Acid Gas [2]
Methane	23,900	0.97	5.37E-03	0.02	3.30E-03
Ethane	22,400	97.15	0.96	1.72	0.55
Propane	21,700	1.25	0.01	0.02	7.14E-03
				1.76	0.56

[1] Based on similar operations at the facility.
[2] Speciated Gas Heating Rate (MMBtu/hr) = Gas Mass Flow Rate (lb/hr) x Component Content (%) / 100 x Higher Heating Value (Btu/lb) x 1 MMBtu / 1,000,000 Btu

Gas Heating Rate of Methane in the Flash Gas (MMBtu/hr) = $\frac{79.1\text{ lb}}{\text{hr}} \times \frac{0.97\%}{100} \times \frac{23{,}900\text{ Btu}}{\text{lb}} \times \frac{1\text{ MMBtu}}{1{,}000{,}000\text{ Btu}}$ = 0.02 MMBtu/hr

Parameter	Units	Flash Gas	Acid Gas
Gas Volume Flow Rate [1]	MMscf/day	0.02	0.55
Gas Mass Flow Rate [1]	lb/hr	79.10	2,571.91
Annual Hours of Operation	hr/yr	8,760	8,760
Flare Destruction Efficiency for C1-C3 [2]	%	99	99
Flare Destruction Efficiency for C4+ [2]	%	98	98

[1] Based on similar operations at the facility.
[2] Per TCEQ Air Permits Division, *Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers*, RG-109 (Draft), October 2000.

Amine Unit Outlet Streams

Speciated Gas	Speciated Gas Percentage (%)	
	Flash Gas [1]	Acid Gas [1]
Carbon Dioxide	0.21	96.52
Methane	0.97	5.37E-03
Ethane	97.15	0.96
Propane	1.25	0.01
Ucarsol AP-810	8.41E-05	5.65E-05
Total VOC Content (%)	1.25	0.01

[1] Based on similar operations at the facility.

Targa Midstream Services LLC - Mont Belvieu Plant
Amine Unit Emissions Calculations

Controlled Flash Gas Emissions [1, 2]

Component	Inlet to Flare (lb/hr)	Destruction Efficiency (%)	Controlled Hourly Emissions (lb/hr)	Controlled Annual Emissions (tpy)
Carbon Dioxide	0.17	0%	0.17	0.72
Methane	0.77	99%	7.71E-03	0.03
Ethane	76.85	99%	0.77	3.37
Propane	0.99	99%	9.90E-03	0.04
Ucarsol AP-810	6.65E-05	98%	1.33E-06	5.83E-06
Total VOC Emissions			9.91E-03	0.04

[1] Emissions based on similar operations at the facility.
[2] Hourly Emissions of VOC (lb/hr) = (100 - (Flare Efficiency (%))/100 x Gas Mass Flow Rate (lb/hr) x VOC Component Content (%)/100

Hourly Emissions of Propane (lb/hr) = $\frac{100\text{-}99\%}{100} \times \frac{79.10 \text{ lb}}{\text{hr}} \times \frac{1.25\%}{100}$ = 9.90E-03 lb/hr

Controlled Acid Gas Emissions [1, 2]

Component	Inlet to Flare (lb/hr)	Destruction Efficiency (%)	Controlled Hourly Emissions (lb/hr)	Controlled Annual Emissions (tpy)
Carbon Dioxide	2482.41	0%	2,482.41	10,872.95
Methane	0.14	99%	1.38E-03	6.05E-03
Ethane	24.65	99%	0.25	1.08
Propane	0.33	99%	3.29E-03	0.01
Ucarsol AP-810	1.45E-03	98%	2.90E-05	1.27E-04
Total VOC Emissions			3.32E-03	0.01

[1] Emissions based on similar operations at the facility.
[2] Hourly Emissions of VOC (lb/hr) = (100 - (Flare Efficiency (%))/100 x Gas Mass Flow Rate (lb/hr) x VOC Component Content (%)/100

Hourly Emissions of Propane (lb/hr) = $\frac{100\text{-}99\%}{100 \text{ hr}} \times \frac{2{,}571.91 \text{ lb}}{\text{hr}} \times \frac{1.25\%}{100}$ = 3.29E-03 lb/hr

Targa Midstream Services LLC - Mont Belvieu Plant
Amine Unit Emissions Calculations

FLR-5 Combustion Emissions from AU-4

				Hourly Emissions (lb/hr)					Annual Emissions (tpy)				
FIN	EPN	Source Name	Gas Stream	NO_x [1]	CO [1]	VOC [2]	SO_2 [3,4,7,8]	H_2S [3,4,5,6]	NO_x [9]	CO [9]	VOC [2]	SO_2 [10,11]	H_2S [10,11]
AU-4	FLR-5	Amine Unit	Flash Gas	0.11	0.97	9.91E-03	--	--	0.49	4.24	0.04	--	--
			Acid Gas	0.04	0.31	3.32E-03	0.09	9.32E-04	0.16	1.35	0.01	0.19	2.04E-03
			Total	0.15	1.28	0.01	0.09	9.32E-04	0.65	5.59	0.06	0.19	2.04E-03

[1] Hourly Emissions of NO_x or CO (lb/hr) = Emission Factor (lb/MMBtu) x Gas Heating Rate (MMBtu/hr)

Flash Gas Hourly Emissions of NO_x (lb/hr) =	0.064 lb / MMBtu	1.76 MMBtu / hr	=	0.11 lb/hr

[2] VOC emissions estimated above.

[3] The hourly emission rates for H_2S and SO_2 are 200% the daily average for conservative purposes.

[4] The inlet volume flow rate containing H_2S is 110,000 barrels/day

[5] The specific gravity of the stream containing H_2S is 0.484

[6] Hourly Emissions of H_2S (lb/hr) = 2 * (1-(Flare Destruction Efficiency (%) / 100)) * (H_2S Emission Factor (ppmw) / 1,000,000) * Volume Flow Rate (barrels/day) * 42 (gal/barrel) * 8.34 (lb/gal) * Specific Gravity * 1 / 24 (day/hr)

Hourly Emissions of H_2S (lb/hr) =	2	1-(98%/100)	0.03 parts H2S / 1,000,000	110,000 barrels / day	42 gal / barrel	8.34 lb / gal	0.484	1 day / 24 hr	=	9.32E-04 lb/hr

[7] The molecular weight ratio of SO_2/H_2S is 1.88

[8] Hourly Emissions of SO_2 (lb/hr) = 2 * (Flare Destruction Efficiency (%) / 100) * (H_2S Emission Factor (ppmw) / 1,000,000) * Volume Flow Rate (barrels/day) * 42 (gal/barrel) * Specific Gravity * Molecular Weight Ratio of SO_2/H_2S * 1 / 24 (day/hr)

Hourly Emissions of SO_2 (lb/hr) =	2	98% / 100	0.03 parts H2S / 1,000,000	110,000 barrels / day	42 gal / barrel	8.34 lb / gal	0.48	1.88	1 day / 24 hr	=	0.09 lb/hr

[9] Annual Emissions of NO_x or CO (tpy) = Hourly Emissions (lb/hr) x 8,760 (hr/yr) x 1 ton / 2,000 lb

Flash Gas Annual Emissions of NO_x (tpy) =	0.11 lb / hr	8760 hr / yr	1 ton / 2,000 lb	=	0.49 tpy

[10] H_2S and SO_2 annual emissions rates do not include the conservative safety factor of 200%.

[11] H_2S and SO_2 Annual Emissions (tpy) = Hourly Emissions (lb/hr) * 8,760 (hr/yr) * 1 / 2,000 (ton/lb) * 1 / 2

Annual Emissions of H_2S (tpy) =	0.09 lb / hr	8,760 hr / yr	1 ton / 2,000 lb	1 / 2	=	0.19 tpy

Targa Midstream Services LLC - Mont Belvieu Plant
Combustion Emissions

Natural Gas Combustion Emission Factors

Units	CO [1]	NO_x [2]	$PM/PM_{10}/PM_{2.5}$ [1]	SO_2 [3, 5]	VOC [4, 5]	NH_3 [6, 7, 8, 9, 10]
lb/MMscf	--	--	--	0.6	0.62	--
lb/MMBtu	0.037	0.005	0.0040	0.0006	0.0006	0.003
ppmvd	--	--	--	--	--	7

[1] Per manufacturer guarantee.
[2] Both heaters will be equipped with low NO_x burners and a selective catalyst reduction (SCR) system.
[3] Emissions factors are from U.S. EPA, AP-42, Section 1.4, July 1998, Table 1.4-2.
[4] VOC emission factor for boilers > 100 MMBtu/hr
[5] Per AP-42 Table 1.4-2, footnote 'a': emission factors converted to the facility heating value by multiplying by the ratio of the fuel specific higher heating value to the average heating value (1,015/1,020).
Emission factors converted from MMscf to MMBtu, based on the facility heating value of 1,015 MMBtu/MMscf.
[6] Estimated ammonia slip rate.
[7] Emissions factor converted from ppmvd to lb/MMBtu, based on U.S. EPA Modified Method 19 and a NH_3 molecular 17.03 lb/lb-mol.
[8] The F_d factor 8,710 dscf/MMBtu for natural gas is from U.S. EPA, Method 19, Table 19-2.
[9] Per the ideal gas law at standard conditions, [14.7 (psia) / (10.73 (scf x psia / lb-mol x R) x (68 (°F) + 459.67 R) x 1(2.60E-09 lb-mol/dscf.
[10] NH_3 Emission Factor (lb/MMBTU) = ppmvd x Molecular Weight (lb/lb-mol) x (2.60 lb-mol/dscf) * F_d x [20.9/(20.9 - %O_2)]

NH_3 Emission Factor (lb/MMBtu) = 7 ppmvd | 17.03 lb / lb-mol | 2.60E-09 lb-mol / dscf | 8,710 dscf / MMBtu | 20.9 / 20.9 - 3% = 0.003 lb/MMBtu

Proposed Hourly and Annual Combustion Emissions for Heaters

FIN	EPN	Source Name	Maximum Design Capacity [1] (MMBtu/hr)	Annual Hours of Operation (hr/yr)	Hourly Emissions (lb/hr) [2] CO	NO_x	$PM/PM_{10}/PM_{2.5}$	SO_2	VOC	NH_3	Annual Emissions (tpy) [3] CO	NO_x	$PM/PM_{10}/PM_{2.5}$	SO_2	VOC	NH_3
F5A	F5A	Hot Oil Heater	144.45	8,760	5.34	0.72	0.58	0.08	0.09	0.46	23.41	3.16	2.53	0.37	0.38	1.99
F5B	F5B	Hot Oil Heater	144.45	8,760	5.34	0.72	0.58	0.08	0.09	0.46	23.41	3.16	2.53	0.37	0.38	1.99

[1] Per manufacturer guarantee
[2] Hourly Emissions (lb/hr) = Emissions Factor (lb/MMBtu) x Maximum Design Capacity (MMBtu/hr)

CO Hourly Emissions (lb/hr) = 0.037 lb CO / MMBtu | 144.45 MMBtu / hr = 5.34 lb/hr

[3] Annual Emission (tpy) = Hourly Emissions (lb/hr) x Annual Operating Hours (hrs/yr) * 1/2,000 (ton/lb)

CO Annual Emissions (tpy) = 5.34 lb CO / hr | 8,760 hrs / yr | 1 ton / 2,000 lb = 23.41 tpy

Targa Midstream Services LLC - Mont Belvieu Plant
Fugitives Emissions Calculations

Product Stream Fugitive Component Counts and VOC Contents

Product Stream	Number of Valves Gas/Vapor	Number of Valves Liquid	Number of Flanges Gas/vapor	Number of Flanges Liquid	VOC Content (%)
YGRD	0	136	31	279	55.73
DC2T	53	479	121	1085	1.41
DC2B	7	61	16	142	98.44
DC3T	66	375	102	917	96.06
DC3B	6	50	13	118	100.00
DC4T	14	124	31	277	100.00
DC4B	23	211	52	471	100.00
C4ST	29	261	66	592	100.00
C4SB	27	246	64	576	100.00
FUELGAS	71	0	220	0	1.80

Oil and Gas Production Operations Emission Factors

Equipment	Units	Gas [1]	Liquid [1]
Valves	(lb/hr)/component	0.00992	0.0055
Flanges	(lb/hr)/component	0.00086	0.000243

[1] Oil and Gas Production emission factors obtained from TCEQ guidance:
http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/fac_specific.pdf, Accessed February 2012.

TCEQ LDAR Control Efficiencies

LDAR Program	Units	Gas [1]	Liquid [1]
Valves	%	97	97
Flanges	%	97	97

[1] Control efficiencies for 28VHP LDAR program obtained from TCEQ guidance:
http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/control_eff.pdf, Accessed February 2012. Targa will monitor flanges using quarterly OVA monitoring at the same leak definition for valves; therefore, the 97% control efficiency may be used for flanges.

Targa Midstream Services LLC - Mont Belvieu Plant
Fugitives Emissions Calculations

Proposed Hourly and Annual Emissions from Fugitive Components

			Hourly Emissions (lb/hr) [1]					Annual Emissions (tpy) [2]				
			Valves		Flanges			Valves		Flanges		
FIN	**EPN**	**Product Stream**	**Gas**	**Liquid**	**Gas**	**Liquid**	**Total**	**Gas**	**Liquid**	**Gas**	**Liquid**	**Total**
FUG-FRAC5	FUG-FRAC5	YGRD	-	0.01	4.46E-04	1.13E-03	0.01	-	0.05	1.95E-03	4.96E-03	0.06
FUG-FRAC5	FUG-FRAC5	DC2T	2.22E-04	1.11E-03	4.40E-05	1.11E-04	1.49E-03	9.74E-04	4.88E-03	1.93E-04	4.88E-04	6.53E-03
FUG-FRAC5	FUG-FRAC5	DC2B	2.05E-03	9.91E-03	4.06E-04	1.02E-03	0.01	8.98E-03	0.04	1.78E-03	4.46E-03	0.06
FUG-FRAC5	FUG-FRAC5	DC3T	0.02	0.06	2.53E-03	6.42E-03	0.09	0.08	0.26	0.01	0.03	0.38
FUG-FRAC5	FUG-FRAC5	DC3B	1.79E-03	8.25E-03	3.35E-04	8.60E-04	0.01	7.82E-03	0.04	1.47E-03	3.77E-03	0.05
FUG-FRAC5	FUG-FRAC5	DC4T	4.17E-03	0.02	8.00E-04	2.02E-03	0.03	0.02	0.09	3.50E-03	8.84E-03	0.12
FUG-FRAC5	FUG-FRAC5	DC4B	6.84E-03	0.03	1.34E-03	3.43E-03	0.05	0.03	0.15	5.88E-03	0.02	0.20
FUG-FRAC5	FUG-FRAC5	C4ST	8.63E-03	0.04	1.70E-03	4.32E-03	0.06	0.04	0.19	7.46E-03	0.02	0.25
FUG-FRAC5	FUG-FRAC5	C4SB	8.04E-03	0.04	1.65E-03	4.20E-03	0.05	0.04	0.18	7.23E-03	0.02	0.24
FUG-FRAC5	FUG-FRAC5	FUELGAS	3.80E-04	-	1.02E-04	-	4.82E-04	1.66E-03	-	4.47E-04	-	2.11E-03
		Total	0.05	0.23	9.36E-03	0.02	0.31	0.22	1.01	0.04	0.10	1.38

[1] Hourly Emissions (lb/hr) = Component Count x Emission Factor [(lb/hr)/ component] x VOC Content (%) / 100 x (1 - (28 VHP Control (%)) / 100)

Hourly Emissions from Product Stream DC2T (lb/hr) = 53.00 | 0.00992 lb / hr-component | 1.41 / 100 | 1-(97/100) = 2.22E-04 lb/hr

[2] Annual Emissions (tpy) = Hourly Emissions (lb/hr) x 8,760 (hr/yr) x 1 ton /2,000 lb

Annual Emissions for Product Stream DC2T (tpy) = 2.22E-04 lb / hr | 8,760 hr / yr | 1 ton / 2,000 lb = 9.74E-04 tpy

VOC Speciation

	Product Stream Weight Percent (%)									
Component	**FUELGAS**	**YGRD**	**DC2T**	**DC2B**	**DC3T**	**DC3B**	**DC4T**	**DC4B**	**C4ST**	**C4SB**
Propane	0.71	21.32	1.41	36.98	93.31	0.15	0.26	2.97E-09	0.96	-
i-Butane	0.23	6.03	3.96E-08	10.76	2.59	16.11	29.25	0.01	97.11	3.13
n-Butane	0.21	13.37	1.66E-09	23.88	0.16	39.40	69.18	2.90	1.88	96.32
i-Pentane	0.15	4.43	-	7.91	1.50E-06	13.09	1.23	27.61	-	0.52
n-Pentane	0.08	3.86	-	6.89	1.25E-07	11.40	0.05	25.32	-	0.01
n-Hexane	0.43	0.90	-	1.61	-	2.67	2.17E-10	5.94	-	2.68E-10
n-Heptane	-	5.44	-	9.72	-	16.07	-	35.77	-	-
COS	-	5.88E-04	3.45E-04	7.79E-04	1.97E-03	1.32E-07	2.40E-07	-	8.78E-07	-
Methyl Mercaptan	-	3.73E-03	3.47E-09	6.66E-03	3.79E-03	8.53E-03	0.02	7.20E-05	0.04	4.10E-03
Ethyl Mercaptan	-	4.21E-03	-	7.52E-03	1.12E-06	0.01	9.18E-03	0.02	8.30E-12	0.01
Dimethyl Sulfide	-	8.52E-04	-	1.52E-03	7.08E-08	2.52E-03	1.80E-03	3.39E-03	8.09E-12	1.94E-03
n-Propyl Mercaptan	-	4.88E-03	-	8.71E-03	1.50E-13	0.01	3.79E-09	0.03	-	7.96E-10
n-Butyl Mercaptan	-	2.41E-04	-	4.30E-04	-	7.12E-04	-	1.58E-03	-	-
Dimethyl Disulfide	-	2.09E-04	-	3.73E-04	-	6.17E-04	-	1.37E-03	-	-
Diethyl Disulfide	-	2.94E-04	-	5.25E-04	-	8.69E-04	-	1.93E-03	-	-
Benzene	-	0.12	-	0.21	-	0.35	2.66E-11	0.78	-	5.94E-12
Toluene	-	0.13	-	0.22	-	0.37	-	0.82	-	-
Ethylbenzene	-	0.08	-	0.15	-	0.24	-	0.54	-	-
m-Xylene	-	0.04	-	0.07	-	0.12	-	0.26	-	-
Total	1.80	55.73	1.41	98.44	96.06	100.00	100.00	100.00	100.00	100.00

[1] Based on similar operations at the facility.

Targa Midstream Services LLC - Mont Belvieu Plant
Fugitives Emissions Calculations

Speciated Hourly Emissions from Fugitive Components

Component	FUELGAS	YGRD	DC2T	DC2B	DC3T	DC3B	DC4T	DC4B	C4ST	C4SB	Total
					Hourly Emissions (lb/hr) [1]						
Propane	1.90E-04	5.39E-03	1.49E-03	5.03E-03	0.08	1.63E-05	7.24E-05	1.38E-12	5.55E-04	-	0.10
i-Butane	6.08E-05	1.52E-03	4.19E-11	1.46E-03	2.35E-03	1.81E-03	8.03E-03	5.48E-06	0.06	1.70E-03	0.07
n-Butane	5.54E-05	3.38E-03	1.76E-12	3.25E-03	1.41E-04	4.43E-03	0.02	1.34E-03	1.09E-03	0.05	0.09
i-Pentane	4.06E-05	1.12E-03	-	1.08E-03	1.36E-09	1.47E-03	3.38E-04	0.01	-	2.83E-04	0.02
n-Pentane	2.03E-05	9.75E-04	-	9.37E-04	1.13E-10	1.28E-03	1.27E-05	0.01	-	7.34E-06	0.01
n-Hexane	1.14E-04	2.28E-04	-	2.19E-04	-	3.00E-04	5.95E-14	2.76E-03	-	1.46E-13	3.62E-03
n-Heptane	-	1.37E-03	-	1.32E-03	-	1.80E-03	-	0.02	-	-	0.02
COS	-	1.49E-07	3.65E-07	1.06E-07	1.79E-06	1.49E-11	6.60E-11	-	5.07E-10	-	2.41E-06
Methyl Mercaptan	-	9.42E-07	3.67E-12	9.05E-07	3.44E-06	9.59E-07	4.24E-06	3.34E-08	2.42E-05	2.23E-06	3.70E-05
Ethyl Mercaptan	-	1.06E-06	-	1.02E-06	1.02E-09	1.40E-06	2.52E-06	7.63E-06	4.79E-15	6.28E-06	1.99E-05
Dimethyl Sulfide	-	2.15E-07	-	2.07E-07	6.43E-11	2.83E-07	4.94E-07	1.58E-06	4.67E-15	1.06E-06	3.83E-06
n-Propyl Mercaptan	-	1.23E-06	-	1.18E-06	1.36E-16	1.62E-06	1.04E-12	1.49E-05	-	4.34E-13	1.89E-05
n-Butyl Mercaptan	-	6.09E-08	-	5.85E-08	-	8.00E-08	-	7.36E-07	-	-	9.35E-07
Dimethyl Disulfide	-	5.28E-08	-	5.07E-08	-	6.93E-08	-	6.38E-07	-	-	8.11E-07
Diethyl Disulfide	-	7.43E-08	-	7.14E-08	-	9.76E-08	-	8.98E-07	-	-	1.14E-06
Benzene	-	2.99E-05	-	2.87E-05	-	3.92E-05	7.30E-15	3.61E-04	-	3.23E-15	4.59E-04
Toluene	-	3.16E-05	-	3.04E-05	-	4.15E-05	-	3.82E-04	-	-	4.86E-04
Ethylbenzene	-	2.07E-05	-	1.99E-05	-	2.71E-05	-	2.50E-04	-	-	3.17E-04
m-Xylene	-	1.00E-05	-	9.64E-06	-	1.32E-05	-	1.21E-04	-	-	1.54E-04

[1] Speciated Hourly Emissions (lb/hr) = Total Hourly Emissions per Product Stream (lb/hr) x (Component Weight Percent (%) /100) / VOC Content (%) / 100

Propane Speciated Hourly Emissions for Product Stream FUELGAS (lb/hr) = 4.82E-04 lb / hr | 0.71 % / 100 | 100 / 1.80 % = 1.90E-04 lb/hr

Speciated Annual Emissions from Fugitive Components

Component	FUELGAS	YGRD	DC2T	DC2B	DC3T	DC3B	DC4T	DC4B	C4ST	C4SB	Total
					Annual Emissions (tpy) [1]						
Propane	8.33E-04	0.02	6.53E-03	0.02	0.37	7.14E-05	3.17E-04	6.04E-12	2.43E-03	-	0.43
i-Butane	2.66E-04	6.67E-03	1.83E-10	6.41E-03	0.01	7.93E-03	0.04	2.40E-05	0.25	7.47E-03	0.32
n-Butane	2.43E-04	0.01	7.70E-12	0.01	6.18E-04	0.02	0.08	5.89E-03	4.75E-03	0.23	0.37
i-Pentane	1.78E-04	4.90E-03	-	4.71E-03	5.97E-09	6.44E-03	1.48E-03	0.06	-	1.24E-03	0.08
n-Pentane	8.89E-05	4.27E-03	-	4.11E-03	4.96E-10	5.61E-03	5.58E-05	0.05	-	3.21E-05	0.07
n-Hexane	5.01E-04	1.00E-03	-	9.61E-04	-	1.31E-03	2.61E-13	0.01	-	6.39E-13	0.02
n-Heptane	-	6.02E-03	-	5.79E-03	-	7.91E-03	-	0.07	-	-	0.09
COS	-	6.51E-07	1.60E-06	4.64E-07	7.84E-06	6.51E-11	2.89E-10	-	2.22E-09	-	1.06E-05
Methyl Mercaptan	-	4.13E-06	1.61E-11	3.96E-06	1.51E-05	4.20E-06	1.86E-05	1.46E-07	1.06E-04	9.78E-06	1.62E-04
Ethyl Mercaptan	-	4.66E-06	-	4.48E-06	4.45E-09	6.12E-06	1.10E-05	3.34E-05	2.10E-14	2.75E-05	8.72E-05
Dimethyl Sulfide	-	9.43E-07	-	9.06E-07	2.82E-10	1.24E-06	2.16E-06	6.90E-06	2.05E-14	4.63E-06	1.68E-05
n-Propyl Mercaptan	-	5.40E-06	-	5.19E-06	5.96E-16	7.09E-06	4.55E-12	6.52E-05	-	1.90E-12	8.29E-05
n-Butyl Mercaptan	-	2.67E-07	-	2.56E-07	-	3.50E-07	-	3.22E-06	-	-	4.10E-06
Dimethyl Disulfide	-	2.31E-07	-	2.22E-07	-	3.04E-07	-	2.79E-06	-	-	3.55E-06
Diethyl Disulfide	-	3.26E-07	-	3.13E-07	-	4.27E-07	-	3.93E-06	-	-	5.00E-06
Benzene	-	1.31E-04	-	1.26E-04	-	1.72E-04	3.20E-14	1.58E-03	-	1.42E-14	2.01E-03
Toluene	-	1.39E-04	-	1.33E-04	-	1.82E-04	-	1.67E-03	-	-	2.13E-03
Ethylbenzene	-	9.06E-05	-	8.70E-05	-	1.19E-04	-	1.09E-03	-	-	1.39E-03
m-Xylene	-	4.40E-05	-	4.22E-05	-	5.77E-05	-	5.31E-04	-	-	6.75E-04

[1] Speciated Annual Emissions (tpy) = Hourly Emissions (lb/hr) x 8,760 (hr/yr) x 1 ton /2,000 lb

Propane Speciated Annual Emissions for Product Stream FUELGAS (tpy) = 1.90E-04 lb / hr | 8,760 hr / yr | 1 ton / 2,000 lb = 8.33E-04 tpy

Targa Midstream Services LLC - Mont Belvieu Plant
Cooling Tower Emissions

Design Specifications

Parameter	Units	Value
Water Circulation Rate [1]	gpm	44,322
Operating Hours [2]	hrs/yr	8,760
Drift Rate [3]	%	0.0005
TDS [3]	ppmw	5,000
THC Leak Factor [3,4]	ppmw	0.08
VOC Content [3]	%	91.70

[1] Per Industrial Cooling Solutions, New Cooling Tower Proposal No. N10111R0, dated November 18, 2010.
[2] Assumed the annual hours of operations to be 8,760 hrs/yr.
[3] Based on similar operations at the facility.
[4] The THC Leak Factor is based on a total hydrocarbon content (THC).

Proposed Hourly and Annual Emissions from Cooling Tower

FIN	EPN	Source Name	$PM_{10}/PM_{2.5}$ Portion of PM (%) [1, 6]	Hourly Emissions (lb/hr) [2, 3, 4] PM	$PM_{10}/PM_{2.5}$ [6]	VOC	Annual Emissions (tpy) [5] PM	$PM_{10}/PM_{2.5}$ [6]	VOC
FUG-CT-9	FUG-CT-9	Cooling Tower 9	30	0.55	0.17	1.63	2.43	0.73	7.13

[1] Joel Reisman and Gordon Frisbie, Greystone Environmental Consultants, Inc., *Calculating Realistic PM $_{10}$ Emissions from Cooling Tower,* Abstract No. 216, Figure 1 (30% for TDS of 5,000 ppmw).

[2] Hourly Emissions of PM (lb/hr) = Water Circulation Rate (gpm) x Drift Rate (%) / 100 x TDS (ppmw) x 8.34 (lb water/gal) x 60 (min/hr)

$$\text{Hourly Emissions of PM (lb/hr)} = \frac{44{,}322 \text{ gal}}{\text{min}} \left| \frac{0.0005\ \%}{100} \right| \frac{5{,}000 \text{ parts solids}}{1{,}000{,}000 \text{ parts water}} \left| \frac{8.34 \text{ lb water}}{\text{gal}} \right| \frac{60 \text{ min}}{\text{hr}} = 0.55 \text{ lb/hr}$$

[3] Hourly Emissions of $PM_{10}/PM_{2.5}$ (lb/hr) = Hourly Emissions of PM (lb/hr) x $PM_{10}/PM_{2.5}$ Portion of PM (%) / 100

$$\text{Hourly Emissions of } PM_{10}/PM_{2.5} \text{ (lb/hr)} = \frac{0.55 \text{ lb}}{\text{hr}} \left| \frac{30\ \%}{100} \right. = 0.17 \text{ lb/hr}$$

[4] Hourly Emissions of VOC (lb/hr) = Water Circulation Rate (gpm) x 8.34 (lb water/gal) x 60 (min/hr) x THC Leak Factor (ppmw) x VOC Content (%) / 100

$$\text{Hourly Emissions of VOC (lb/hr)} = \frac{44{,}322 \text{ gal}}{\text{min}} \left| \frac{8.34 \text{ lb water}}{\text{gal}} \right| \frac{60 \text{ min}}{\text{hr}} \left| \frac{0.08 \text{ parts THC}}{1{,}000{,}000 \text{ parts water}} \right| \frac{91.70\ \%\ \text{VOC}}{100} = 1.63 \text{ lb/hr}$$

[5] Annual Emissions (tpy) = Hourly Emissions x 8,760 (hr/yr) x 1 ton/2,000 lb

$$\text{Annual Emissions of PM (tpy)} = \frac{0.55 \text{ lb}}{\text{hr}} \left| \frac{8{,}760 \text{ hr}}{\text{yr}} \right| \frac{1 \text{ ton}}{2{,}000 \text{ lb}} = 2.43 \text{ tpy}$$

[6] $PM_{2.5}$ is conservatively assumed to equal PM_{10}.

Cooling Tower Speciated Emissions

Speciated VOC	VOC Weight Percent (%)	Hourly Emissions [1] (lb/hr)	Annual Emissions [2] (tpy)
Propane	53.62	0.87	3.82
i-Butane	23.72	0.39	1.69
n-Butane	22.52	0.37	1.61
i-Pentane	0.12	1.94E-03	8.50E-03
n-Pentane	3.10E-03	5.04E-05	2.21E-04
n-Hexane	6.15E-11	1.00E-12	4.38E-12
COS	7.08E-04	1.15E-05	5.05E-05
Methyl Mercaptan	1.04E-02	1.69E-04	7.38E-04
Ethyl Mercaptan	2.65E-03	4.31E-05	1.89E-04
Dimethyl Sulfide	4.46E-04	7.26E-06	3.18E-05
n-Propyl Mercaptan	1.83E-10	2.98E-12	1.30E-11
Benzene	1.36E-12	2.22E-14	9.72E-14

[1] Hourly Speciated Emissions (lb/hr) = Hourly Emissions of VOC (lb/hr) x VOC Weight Percent (%) / 100

Hourly Speciated Emissions of VOC Propane (lb/hr) = $\frac{1.63\ \text{lb}}{\text{hr}} \Big| \frac{53.62\ \%}{100}$ = 0.87 lb/hr

[2] Annual Speciated Emissions of VOC (tpy) = Annual Emissions of VOC (tpy) x VOC Weight Percent (%) / 100

Annual Speciated Emissions of VOC Propane (tpy) = $\frac{7.13\ \text{lb}}{\text{hr}} \Big| \frac{53.62\ \%}{100}$ = 3.82 tpy

FLR-5 Emission Factors [1]

Units	CO	NO_x
lb/MMBtu	0.2755	0.138
ppmw	-	-

[1] Flare Emissions factors are from TCEQ Air Permits Division, *Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers,* RG-109 (Draft), October 2000, Table 4 (other, high Btu).

Maintenance Emissions Summary

FIN	EPN	Source Name	Hourly Emissions (lb/hr) VOC [1]	NO_x [2]	CO [2]	Annual Emissions (tpy) VOC [1]	NO_x [3]	CO [3]
Maintenance	FLR-5	Emissions to FLR-5	13.96	0.23	0.47	0.63	6.80E-03	0.01
Maintenance	Maintenance	Emissions to Atmosphere	1.15	-	-	0.01	-	-

[1] VOC emissions calculated below and based on the maximum hourly emissions among all vapor events and all liquid events.
[2] Hourly emissions of NO_x and CO based on the maximum hourly heating rate among all vapor events and liquid events.
Hourly Emissions of NO_x or CO (lb/hr) = Emission Factor (lb/MMBtu) x Gas Heating Rate (MMBtu/hr)

Hourly Emissions of NO_x (lb/hr) = 0.138 lb / MMBtu | 1.69 MMBtu / hr = 0.23 lb/hr

[3] Annual Emissions (tpy) = Emission Factor (lb/MMBtu) x Σ (Hours per Event [hr/event] x Frequency per Year [event/yr] x Gas Heating Rate [MMBtu/hr])

Gas Heating Rates [1]

Speciated Gas	Higher Heating Value (Btu/ft^3)
C1	912
C2	1,699
C3	2,385
iC4	3,105
C4	3,123
iC5	3,705
C5	3,714
C6	4,415
C7	4,415

[1] Per Table 5-7 of *Combined Heating, Cooling & Power Handbook: Technologies & Applications,* by Neil Petchers (2003)

Component Molecular Weights

Component	MW (lb/lb-mol)
C1	16.04
C2	30.07
C3	44.10
iC4	58.12
C4	58.12
iC5	72.15
C5	72.15
C6	86.18
C7	100.21

Targa Midstream Services LLC - Mont Belvieu Plant
Maintenance Emissions Calculations

Vapor Parameters

Unit ID	Description	Hours Per Event (hr/event)	Frequency per Year (event/yr)	ID (ft)	Height (ft)	Total Volume [1] (ft^3/event)	Total Volume Rate [2] (ft^3/hr)	Vapor Density (lb/ft^3)	Vapor Mass Fraction [3] C1	C2	C3	iC4	C4	iC5	C5	C6	C7	Gas Heating Rate [4] (MMBtu/hr)
Filters/Coalescers																		
15-358-1A/B	Plant inlet feed filters	4	104	3	7.25	51	13	3.35	0.0323	0.7766	0.1329	0.0269	0.0199	0.0053	0.0033	0.0004	0.0025	0.0238
15-358-2A/B	Plant feed inlet coalescers	4	104	5	5.25	103	26	3.35	0.0323	0.7766	0.1329	0.0269	0.0199	0.0053	0.0033	0.0004	0.0025	0.0478
15-358-401	Treated Propane Filter Coalescer	4	104	3	5.25	37	9	1.50	0.0000	0.1297	0.8584	0.0109	0.0010	0.0000	0.0000	0.0000	0.0000	0.0214
15-358-501	Treated gasoline coalescer	4	104	2	5.25	22	6	0.12	0.0000	0.0000	0.0000	0.0003	0.0230	0.4936	0.3272	0.0221	0.1338	0.0214
15-358-601	n-butane product coalescer	4	104	3	5.25	37	9	0.40	0.0000	0.0000	0.0000	0.0401	0.9576	0.0021	0.0001	0.0000	0.0000	0.0290
Compressors																		
11-358-1A/B	Ethane	2	6	-	-	2,000	1,000	7.72	0.0203	0.9699	0.0098	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	1.6897
11-358-2A/B	Refrigeration	2	2	-	-	1,200	600	1.50	0.0000	0.1297	0.8584	0.0109	0.0010	0.0000	0.0000	0.0000	0.0000	1.3828
11-358-3	C4 Splitter	2	2	-	-	1,000	500	0.59	0.0000	0.0000	0.0225	0.9647	0.0128	0.0000	0.0000	0.0000	0.0000	1.5445

[1] Total Volume (ft^3/event) = Pi * (ID (ft) / 2)^2 x Height (ft)

Filters/Coalescer 15-358-1A/B Total Volume (ft^3/event) = π | (3 ft / 2)^2 | 7.25 ft = 51 ft^3/event

[2] Total Volume Rate (ft^3/hr) = Total Volume (ft^3/event) / Hours Per Event (hr/event)

Filters/Coalescer 15-358-1A/B Total Volume (ft^3/hr) = 51 ft^3 / event | event / 4 hr = 13 ft^3/hr

[3] The mass fraction ratio of n-hexane to n-hexane and higher is 14.2 %

[4] Speciated Gas Heating Rate (MMBtu/hr) = Gas Volume Flow Rate (ft^3/hr) x Component Mass Fraction x Higher Heating Value (Btu/ft^3) x 1 MMBtu / 1,000,000 Btu

Vapor Emissions to FLR-5[1]

Unit ID	Description	Controlled Weight Per Hour (lb/hr) [2] C1	C2	C3	iC4	C4	iC5	C5	C6	C7
Filters/Coalescers										
15-358-1A/B	Plant inlet feed filters	0.0138	0.3328	0.0570	0.0231	0.0170	0.0045	0.0028	0.0004	0.0022
15-358-2A/B	Plant feed inlet coalescers	0.0278	0.6694	0.1146	0.0465	0.0342	0.0091	0.0056	0.0007	0.0043
15-358-401	Treated Propane Filter Coalescer	0.0000	0.0180	0.1191	0.0030	0.0003	0.0000	0.0000	0.0000	0.0000
15-358-501	Treated gasoline coalescer	0.0000	0.0000	0.0000	0.0000	0.0003	0.0066	0.0044	0.0003	0.0018
15-358-601	n-butane product coalescer	0.0000	0.0000	0.0000	0.0030	0.0718	0.0002	0.0000	0.0000	0.0000
Compressors										
11-358-1A/B	Ethane	1.5689	74.8634	0.7577	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
11-358-2A/B	Refrigeration	0.0000	1.1632	7.7001	0.1954	0.0180	0.0000	0.0000	0.0000	0.0000
11-358-3	C4 Splitter	0.0000	0.0000	0.0668	5.7284	0.0760	0.0000	0.0000	0.0000	0.0000
Emissions [4]		1.57	74.86	7.70	6.00	0.22	0.02	0.01	0.00	0.01

Unit ID	Description	Controlled Weight Per Year (lb/yr) [3] C1	C2	C3	iC4	C4	iC5	C5	C6	C7
Filters/Coalescers										
15-358-1A/B	Plant inlet feed filters	5.7559	138.4448	23.6923	9.6090	7.0795	1.8753	1.1631	0.1483	0.8961
15-358-2A/B	Plant feed inlet coalescers	11.5780	278.4810	47.6569	19.3284	14.2404	3.7722	2.3395	0.2983	1.8025
15-358-401	Treated Propane Filter Coalescer	0.0000	7.4824	49.5299	1.2571	0.1155	0.0000	0.0000	0.0000	0.0000
15-358-501	Treated gasoline coalescer	0.0000	0.0000	0.0000	0.0015	0.1272	2.7360	1.8138	0.1227	0.7415
15-358-601	n-butane product coalescer	0.0000	0.0000	0.0000	1.2505	29.8621	0.0655	0.0031	0.0000	0.0000
Compressors										
11-358-1A/B	Ethane	18.8264	898.3614	9.0920	0.0005	0.0000	0.0000	0.0000	0.0000	0.0000
11-358-2A/B	Refrigeration	0.0000	4.6530	30.8003	0.7817	0.0719	0.0000	0.0000	0.0000	0.0000
11-358-3	C4 Splitter	0.0000	0.0000	0.2672	22.9136	0.3040	0.0000	0.0000	0.0000	0.0000
Emissions [4]		36.16	1,327.42	161.04	55.14	51.80	8.45	5.32	0.57	3.44

[1] C1, C2, and C3 emissions are routed to FLR-5 with a control efficiency of 99% per TCEQ flare guidance.
All other emissions are routed to FLR-5 with a control efficiency of 98% per TCEQ flare guidance.

[2] Controlled Weight Per Hour (lb/hr) = Total Volume Rate (ft^3/hr) x Vapor Density (lb/ft^3) x VOC Component Vapor Mass Fraction x (100-Flare Control Efficiency (%))/100

Filters/Coalescer 15-358-1A/B Controlled C3 Weight Per Hour (lb/hr) = 13 ft^3 / hr | 3.35 lb / ft^3 | 0.13 | 100-99% / 100 = 0.06 lb/hr

[3] Controlled Weight Per Year (lb/yr) = Total Volume (ft^3) x Vapor Density (lb/ft^3) x VOC Component Vapor Mass Fraction x Frequency/Year x (100-Flare Control Efficiency (%))/100

Filters/Coalescer 15-358-1A/B Controlled C3 Weight Per Year (lb/yr) = 51 ft^3 / event | 3.35 lb / ft^3 | 0.13 | 104 events / yr | 100-99% / 100 = 23.69 lb/yr

[4] Hourly emissions are based on the maximum emissions of each of the filters/coalescers and compressors. The annual emissions (lb/yr) are the sum of the speciated emissions of all units.

Liquid Parameters

Unit ID	Description	Hours Per Event (hr/event)	Frequency per Year (event/yr)	ID (ft)	Height (ft)	Total Volume [1] (ft^3/event)	Total Volume Rate [2] (ft^3/hr)	Heel (ft)	Heel Volume [3] (ft^3/event)	Heel Volume Rate (ft^3/hr)	Liquid Density (lb/ft^3)	Component Liquid Mass Fraction[4] C1	C2	C3	iC4	C4	iC5	C5	C6	C7	Gas Heating Rate [5] (MMBtu/hr)
Filters/Coalescers																					
15-358-1A/B	Plant inlet feed filters	2	104	3	7.25	51	26	0.5	4	2	27.23	0.0064	0.5068	0.2101	0.0803	0.0750	0.0374	0.0281	0.0079	0.0479	0.0041
15-358-2A/B	Plant feed inlet coalescers	2	104	5	5.25	103	52	0.5	10	5	27.23	0.0064	0.5068	0.2101	0.0803	0.0750	0.0374	0.0281	0.0079	0.0479	0.0115
15-358-401	Treated Propane Filter Coalescer	2	104	3	5.25	37	19	0.5	4	2	30.27	0.0000	0.0471	0.9241	0.0256	0.0031	0.0000	0.0000	0.0000	0.0000	0.0042
15-358-501	Treated gasoline coalescer	2	104	2.33	5.25	22	11	0.5	2	1	39.49	0.0000	0.0000	0.0000	0.0000	0.0056	0.3064	0.2712	0.0592	0.3576	0.0043
15-358-601	n-butane product coalescer	2	104	3	5.25	37	19	0.5	4	2	35.62	0.0000	0.0000	0.0000	0.0289	0.9656	0.0052	0.0002	0.0000	0.0000	0.0055
Pumps																					
28-358-1A/B	DC2 Reflux Pumps	2	2	-	-	11.24	6	-	-	-	17.03	0.0125	0.9733	0.0142	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0095
28-358-2A/B	DC3 Reflux Pumps	2	2	-	-	11.24	6	-	-	-	30.27	0.0000	0.0471	0.9241	0.0256	0.0031	0.0000	0.0000	0.0000	0.0000	0.0133
28-358-3A/B	C3 Inject pumps	2	2	-	-	11.24	6	-	-	-	30.27	0.0000	0.0471	0.9241	0.0256	0.0031	0.0000	0.0000	0.0000	0.0000	0.0133
28-358-4A/B	DC4 Reflux pumps	2	2	-	-	11.24	6	-	-	-	35.24	0.0000	0.0000	0.0026	0.2901	0.7033	0.0038	0.0002	0.0000	0.0000	0.0175
28-358-5A/B	Gasoline booster pumps	2	2	-	-	11.24	6	-	-	-	39.49	0.0000	0.0000	0.0000	0.0000	0.0056	0.3064	0.2712	0.0592	0.3576	0.0225
28-358-6A/B	Gasoline injection pumps	2	2	-	-	11.24	6	-	-	-	39.49	0.0000	0.0000	0.0000	0.0000	0.0056	0.3064	0.2712	0.0592	0.3576	0.0225
28-358-7A/B	C4 split bottoms pumps	2	2	-	-	11.24	6	-	-	-	34.22	0.0000	0.0000	0.0095	0.9729	0.0176	0.0000	0.0000	0.0000	0.0000	0.0174
28-358-8A/B	C4 split reflux pumps	2	2	-	-	11.24	6	-	-	-	35.62	0.0000	0.0000	0.0000	0.0289	0.9656	0.0052	0.0002	0.0000	0.0000	0.0176
28-358-9A/B	C4 Split comp K.O. drum pumps	2	2	-	-	11.24	6	-	-	-	34.22	0.0000	0.0000	0.0095	0.9729	0.0176	0.0000	0.0000	0.0000	0.0000	0.0174
28-358-10A/B	iC4 injection pumps	2	2	-	-	11.24	6	-	-	-	34.22	0.0000	0.0000	0.0095	0.9729	0.0176	0.0000	0.0000	0.0000	0.0000	0.0174
28-358-11A/B	nC4 injection pumps	2	2	-	-	11.24	6	-	-	-	35.62	0.0000	0.0000	0.0000	0.0289	0.9656	0.0052	0.0002	0.0000	0.0000	0.0176

[1] Total Volume (ft^3/event) = Pi * (ID (ft) / 2)^2 x Height (ft)

Filters/Coalescer 15-358-1A/B Total Volume (ft^3/event) = π | (3 ft / 2)^2 | 7.25 ft = 51 ft^3/event

[2] Total Volume Rate or Heel Volume Rate (ft^3/hr) = Total Volume or Heel Volume (ft^3/event) / Hours Per Event (hr/event)

Filters/Coalescers 15-358-1A/B Total Volume Rate (ft^3/hr) = 51 ft^3 / event | event / 2 hr = 26 ft^3/hr

[3] Heel Volume (ft^3/event) = Pi * (ID (ft)/2)^2 x Heel (ft)

Filters/Coalescers 15-358-1A/B Heel Volume (ft^3/event) = π | (3 ft / 2)^2 | 0.5 ft = 4 ft^3/event

[4] The mass fraction ratio of n-hexane to n-hexane and higher is 14.2 %

[5] Speciated Gas Heating Rate (MMBtu/hr) = Total Volume or Heel Volume Flow Rate (ft^3/hr) x Component Mass Fraction x Higher Heating Value (Btu/ft^3) x 1 MMBtu / 1,000,000 Btu

Liquid Emissions to FLR-5[1]

Unit ID	Description	Controlled Weight Per Hour (lb/hr) [1,2,3] C1	C2	C3	iC4	C4	iC5	C5	C6	C7	Controlled Weight Per Year (lb/yr) [4,5] C1	C2	C3	iC4	C4	iC5	C5	C6	C7
Filters/Coalescers																			
15-358-1A/B	Plant inlet feed filters	0.0031	0.2439	0.1011	0.0773	0.0722	0.0360	0.0271	0.0076	0.0461	0.6406	50.7247	21.0285	16.0742	15.0132	7.4816	5.6325	1.5878	9.5938
15-358-2A/B	Plant feed inlet coalescers	0.0086	0.6774	0.2808	0.2147	0.2005	0.0999	0.0752	0.0212	0.1281	1.7793	140.9020	58.4126	44.6505	41.7034	20.7821	15.6458	4.4105	26.6494
15-358-401	Treated Propane Filter Coalescer	0.0000	0.0252	0.4943	0.0274	0.0034	0.0000	0.0000	0.0000	0.0000	0.0000	5.2408	102.8228	5.6981	0.6991	0.0000	0.0000	0.0000	0.0000
15-358-501	Treated gasoline coalescer	0.0000	0.0000	0.0000	0.0000	0.0048	0.2587	0.2289	0.0500	0.3019	0.0000	0.0000	0.0000	0.0081	0.9911	53.8109	47.6200	10.3924	62.7934
15-358-601	n-butane product coalescer	0.0000	0.0000	0.0000	0.0364	1.2156	0.0066	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	7.5753	252.8498	1.3695	0.0594	0.0000	0.0000
Pumps																			
28-358-1A/B	DC2 Reflux Pumps	0.0119	0.9312	0.0136	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0478	3.7248	0.0544	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
28-358-2A/B	DC3 Reflux Pumps	0.0000	0.0801	1.5716	0.0871	0.0107	0.0000	0.0000	0.0000	0.0000	0.0000	0.3204	6.2863	0.3484	0.0427	0.0000	0.0000	0.0000	0.0000
28-358-3A/B	C3 Inject pumps	0.0000	0.0801	1.5716	0.0871	0.0107	0.0000	0.0000	0.0000	0.0000	0.0000	0.3204	6.2863	0.3484	0.0427	0.0000	0.0000	0.0000	0.0000
28-358-4A/B	DC4 Reflux pumps	0.0000	0.0000	0.0052	1.1488	2.7848	0.0150	0.0006	0.0000	0.0000	0.0000	0.0000	0.0207	4.5950	11.1393	0.0599	0.0026	0.0000	0.0000
28-358-5A/B	Gasoline booster pumps	0.0000	0.0000	0.0000	0.0002	0.0250	1.3596	1.2032	0.2626	1.5865	0.0000	0.0000	0.0000	0.0008	0.1002	5.4383	4.8127	1.0503	6.3461
28-358-6A/B	Gasoline injection pumps	0.0000	0.0000	0.0000	0.0002	0.0250	1.3596	1.2032	0.2626	1.5865	0.0000	0.0000	0.0000	0.0008	0.1002	5.4383	4.8127	1.0503	6.3461
28-358-7A/B	C4 split bottoms pumps	0.0000	0.0000	0.0182	3.7408	0.0678	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0727	14.9632	0.2712	0.0000	0.0000	0.0000	0.0000
28-358-8A/B	C4 split reflux pumps	0.0000	0.0000	0.0000	0.1158	3.8646	0.0209	0.0009	0.0000	0.0000	0.0000	0.0000	0.0000	0.4631	15.4586	0.0837	0.0036	0.0000	0.0000
28-358-9A/B	C4 Split comp K.O. drum pumps	0.0000	0.0000	0.0182	3.7408	0.0678	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0727	14.9632	0.2712	0.0000	0.0000	0.0000	0.0000
28-358-10A/B	iC4 injection pumps	0.0000	0.0000	0.0182	3.7408	0.0678	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0727	14.9632	0.2712	0.0000	0.0000	0.0000	0.0000
28-358-11A/B	nC4 injection pumps	0.0000	0.0000	0.0000	0.1158	3.8646	0.0209	0.0009	0.0000	0.0000	0.0000	0.0000	0.0000	0.4631	15.4586	0.0837	0.0036	0.0000	0.0000
Emissions[6]		0.01	0.93	1.57	3.74	3.86	1.36	1.20	0.26	1.59	2.47	201.23	195.13	125.12	354.41	94.55	78.59	18.49	111.73

[1] Liquids from maintenance activities will be routed to flare tanks, where resultant vapors will be combusted in the flare.
C1, C2, and C3 emissions are routed to FLR-5 with a control efficiency of 99% per TCEQ flare guidance.
All other emissions are routed to FLR-5 with a control efficiency of 98% per TCEQ flare guidance.

[2] Filters and Coalescers Controlled Weight Per Hour (lb/hr) = Heel Volume Rate (ft^3) x Liquid Density (lb/ft^3) x Component Liquid Mass Fraction x (100-Flare Control Efficiency (%))/100

Filters/Coalescer 15-358-1A/B Controlled C3 Weight Per Hour (lb/hr) =	2 ft3 / hr	27.23 lb / ft^3	0.21	100-99% / 100	=	0.1 lb/hr

[3] Pumps Controlled Weight Per Hour (lb/hr) = Total Volume Rate (ft^3/hr) x Liquid Density (lb/ft^3) x Component Liquid Mass Fraction x (100-Flare Control Efficiency (%))/100

Pump 28-358-1A/B C3 Weight Per Hour (lb/hr) =	6 ft3 / hr	17.03 lb / ft^3	0.01	1-99%	=	0.01 lb/hr

[4] Filters and Coalescers Controlled Weight Per Year (lb/yr) = Heel Volume (ft^3/event) x Liquid Density (lb/ft^3) x Component Liquid Mass Fraction * Frequency Per Year (event/yr) x (100-Flare Control Efficiency (%))/100

Filters/Coalescers 15-358-1A/B Controlled C3 Weight Per Year (lb/yr) =	4 ft3 / event	27.23 lb / ft^3	0.21	104 events / yr	100-99% / 100	=	21.03 lb/yr

[5] Pumps Controlled Weight Per Year (lb/yr) = Total Volume (ft^3) x Liquid Density (lb/ft^3) x Component Liquid Mass Fraction x Frequency/Year x (100-Flare Control Efficiency (%))/100

Pump 28-358-1A/B C3 Weight Per Year (lb/yr) =	11.24 ft3 / event	17.03 lb / ft^3	0.01	2 events / yr	100-99% / 100	=	0.05 lb/yr

[6] Hourly emissions are based on the maximum emissions of each of the filters/coalescers and compressors. The annual emissions (lb/yr) are the sum of the speciated emissions of all units.

Uncontrolled Emissions Sent to Atmosphere Parameters

Unit ID [1]	Description [1]	Hours Per Event (hr/event)	Frequency per Year (event/yr)	ID (ft)	Height (ft)	Total Volume [1] (ft^3/event)	Total Volume Rate [2] (ft^3/hr)	Molar VOC Content [3,4] (lb-mol/yr)	Vapor Mass Fraction [5] C1	C2	C3	iC4	C4	iC5	C5	C6	C7
Filters/Coalescers																	
15-358-1A/B	Plant inlet feed filters	1	104	3	7.25	51	51	0.14	0.0633	0.8119	0.0947	0.0146	0.0107	0.0023	0.0014	0.0002	0.0009
15-358-2A/B	Plant feed inlet coalescers	1	104	5	5.25	103	103	0.28	0.0633	0.8119	0.0947	0.0146	0.0107	0.0023	0.0014	0.0002	0.0009
15-358-401	Treated Propane Filter Coalescer	1	104	3	5.25	37	37	0.10	0.0000	0.1798	0.8117	0.0078	0.0007	0.0000	0.0000	0.0000	0.0000
15-358-501	Treated gasoline coalescer	1	104	2.33	5.25	22	22	0.06	0.0000	0.0000	0.0000	0.0003	0.0291	0.5036	0.3338	0.0189	0.1143
15-358-601	n-butane product coalescer	1	104	3	5.25	37	37	0.10	0.0000	0.0000	0.0000	0.0401	0.9581	0.0017	0.0001	0.0000	0.0000
Pumps																	
28-358-1A/B	DC2 Reflux Pumps	1	2	-	-	11.24	11	0.00	0.0375	0.9559	0.0066	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
28-358-2A/B	DC3 Reflux Pumps	1	2	-	-	11.24	11	0.00	0.0000	0.1798	0.8117	0.0078	0.0007	0.0000	0.0000	0.0000	0.0000
28-358-3A/B	C3 Inject pumps	1	2	-	-	11.24	11	0.00	0.0000	0.1798	0.8117	0.0078	0.0007	0.0000	0.0000	0.0000	0.0000
28-358-4A/B	DC4 Reflux pumps	1	2	-	-	11.24	11	0.00	0.0000	0.0000	0.0104	0.3604	0.6281	0.0011	0.0000	0.0000	0.0000
28-358-5A/B	Gasoline booster pumps	1	2	-	-	11.24	11	0.00	0.0000	0.0000	0.0000	0.0003	0.0291	0.5036	0.3338	0.0189	0.1143
28-358-6A/B	Gasoline injection pumps	1	2	-	-	11.24	11	0.00	0.0000	0.0000	0.0000	0.0003	0.0291	0.5036	0.3338	0.0189	0.1143
28-358-7A/B	C4 split bottoms pumps	1	2	-	-	11.24	11	0.00	0.0000	0.0000	0.0294	0.9578	0.0127	0.0000	0.0000	0.0000	0.0000
28-358-8A/B	C4 split reflux pumps	1	2	-	-	11.24	11	0.00	0.0000	0.0000	0.0000	0.0401	0.9581	0.0017	0.0001	0.0000	0.0000
28-358-9A/B	C4 Split comp K.O. drum pumps	1	2	-	-	11.24	11	0.00	0.0000	0.0000	0.0294	0.9578	0.0127	0.0000	0.0000	0.0000	0.0000
28-358-10A/B	iC4 injection pumps	1	2	-	-	11.24	11	0.00	0.0000	0.0000	0.0294	0.9578	0.0127	0.0000	0.0000	0.0000	0.0000
28-358-11A/B	nC4 injection pumps	1	2	-	-	11.24	11	0.00	0.0000	0.0000	0.0000	0.0401	0.9581	0.0017	0.0001	0.0000	0.0000
Compressors																	
11-358-1A/B	Ethane	1	6	-	-	2,000	2,000	0.32	0.0375	0.9559	0.0066	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
11-358-2A/B	Refrigeration	2	2	-	-	1,200	600	0.06	0.0000	0.1798	0.8117	0.0078	0.0007	0.0000	0.0000	0.0000	0.0000
11-358-3	C4 Splitter	3	2	-	-	1,000	333	0.05	0.0000	0.0000	0.0294	0.9578	0.0127	0.0000	0.0000	0.0000	0.0000

[1] Total Volume (ft^3/event) = Pi * (ID (ft) / 2)^2 x Height (ft)

Filters/Coalescer 15-358-1A/B Total Volume (ft^3/event) = π | (3 ft / 2)^2 | 7.25 ft = 51 ft^3/event

[2] Total Volume Rate or Heel Volume Rate (ft^3/hr) = Total Volume or Heel Volume (ft^3/event) / Hours Per Event (hr/event)

Filters/Coalescers 15-358-1A/B Total Volume Rate (ft^3/hr) = 51 ft^3 / event | event / 1 hr = 51 ft^3/hr

[3] Emission calculations are based on a VOC content of 10,000 ppmv

[4] Molar VOC Content (lb-mol/yr) = (Frequency/Year) / (379.5 scf/lb-mol) x Total Volume (ft^3/event) x VOC Concentration (ppmv) / 1,000,000

Filter/Coalescers 15-358-1A/B Molar VOC Content(lb-mol/yr) = 104 / yr | lb-mol / 379.5 scf | 51 ft3 / event | 10,000 ppmv / 1,000,000 = 0.14 lb-mol/yr

[5] The mass fraction ratio of n-hexane to n-hexane and higher is 14.2 %

Targa Midstream Services LLC - Mont Belvieu Plant
Maintenance Emissions Calculations

Uncontrolled Emissions Sent to Atmosphere

Uncontrolled Weight Per Hour (lb/hr) [1,2]

Unit ID	Description	C1	C2	C3	iC4	C4	iC5	C5	C6	C7
Filters/Coalescers										
15-358-1A/B	Plant inlet feed filters	0.1371	3.2967	0.0056	0.0011	0.0008	0.0002	0.0001	0.0000	0.0001
15-358-2A/B	Plant feed inlet coalescers	0.2757	6.6312	0.0113	0.0023	0.0017	0.0004	0.0003	0.0000	0.0002
15-358-401	Treated Propane Filter Coalescer	0.0000	0.5287	0.0350	0.0004	0.0000	0.0000	0.0000	0.0000	0.0000
15-358-501	Treated gasoline coalescer	0.0000	0.0000	0.0000	0.0000	0.0010	0.0215	0.0142	0.0010	0.0068
15-358-601	n-butane product coalescer	0.0000	0.0000	0.0000	0.0023	0.0545	0.0001	0.0000	0.0000	0.0000
Pumps		0.0000	0.0000							
28-358-1A/B	DC2 Reflux Pumps	0.0178	0.8510	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
28-358-2A/B	DC3 Reflux Pumps	0.0000	0.1601	0.0106	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000
28-358-3A/B	C3 Inject pumps	0.0000	0.1601	0.0106	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000
28-358-4A/B	DC4 Reflux pumps	0.0000	0.0000	0.0001	0.0062	0.0108	0.0000	0.0000	0.0000	0.0000
28-358-5A/B	Gasoline booster pumps	0.0000	0.0000	0.0000	0.0000	0.0005	0.0108	0.0071	0.0005	0.0034
28-358-6A/B	Gasoline injection pumps	0.0000	0.0000	0.0000	0.0000	0.0005	0.0108	0.0071	0.0005	0.0034
28-358-7A/B	C4 split bottoms pumps	0.0000	0.0000	0.0004	0.0165	0.0002	0.0000	0.0000	0.0000	0.0000
28-358-8A/B	C4 split reflux pumps	0.0000	0.0000	0.0000	0.0007	0.0165	0.0000	0.0000	0.0000	0.0000
28-358-9A/B	C4 Split comp K.O. drum pumps	0.0000	0.0000	0.0004	0.0165	0.0002	0.0000	0.0000	0.0000	0.0000
28-358-10A/B	iC4 injection pumps	0.0000	0.0000	0.0004	0.0165	0.0002	0.0000	0.0000	0.0000	0.0000
28-358-11A/B	nC4 injection pumps	0.0000	0.0000	0.0000	0.0007	0.0165	0.0000	0.0000	0.0000	0.0000
Compressors		0.0000	0.0000							
11-358-1A/B	Ethane	3.1744	151.4714	0.0153	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
11-358-2A/B	Refrigeration	0.0000	8.5483	0.5659	0.0072	0.0007	0.0000	0.0000	0.0000	0.0000
11-358-3	C4 Splitter	0.0000	0.0000	0.0114	0.4890	0.0065	0.0000	0.0000	0.0000	0.0000
Emissions [4]		3.1744	151.4714	0.5659	0.4890	0.0545	0.0215	0.0142	0.0010	0.0068

Uncontrolled Weight Per Year (lb/yr) [3]

Unit ID	Description	C1	C2	C3	iC4	C4	iC5	C5	C6	C7
Filters/Coalescers										
15-358-1A/B	Plant inlet feed filters	14.2548	342.8530	0.5868	0.1190	0.0877	0.0232	0.0144	0.0018	0.0129
15-358-2A/B	Plant feed inlet coalescers	28.6734	689.6469	1.1803	0.2393	0.1763	0.0467	0.0290	0.0037	0.0260
15-358-401	Treated Propane Filter Coalescer	0.0000	54.9862	3.6402	0.0462	0.0042	0.0000	0.0000	0.0000	0.0000
15-358-501	Treated gasoline coalescer	0.0000	0.0000	0.0000	0.0012	0.1039	2.2353	1.4818	0.1003	0.7044
15-358-601	n-butane product coalescer	0.0000	0.0000	0.0000	0.2371	5.6631	0.0124	0.0006	0.0000	0.0000
Pumps		0.0000	0.0000							
28-358-1A/B	DC2 Reflux Pumps	0.0357	1.7019	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
28-358-2A/B	DC3 Reflux Pumps	0.0000	0.3202	0.0212	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000
28-358-3A/B	C3 Inject pumps	0.0000	0.3202	0.0212	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000
28-358-4A/B	DC4 Reflux pumps	0.0000	0.0000	0.0003	0.0124	0.0216	0.0000	0.0000	0.0000	0.0000
28-358-5A/B	Gasoline booster pumps	0.0000	0.0000	0.0000	0.0000	0.0010	0.0215	0.0143	0.0010	0.0068
28-358-6A/B	Gasoline injection pumps	0.0000	0.0000	0.0000	0.0000	0.0010	0.0215	0.0143	0.0010	0.0068
28-358-7A/B	C4 split bottoms pumps	0.0000	0.0000	0.0008	0.0330	0.0004	0.0000	0.0000	0.0000	0.0000
28-358-8A/B	C4 split reflux pumps	0.0000	0.0000	0.0000	0.0014	0.0330	0.0001	0.0000	0.0000	0.0000
28-358-9A/B	C4 Split comp K.O. drum pumps	0.0000	0.0000	0.0008	0.0330	0.0004	0.0000	0.0000	0.0000	0.0000
28-358-10A/B	iC4 injection pumps	0.0000	0.0000	0.0008	0.0330	0.0004	0.0000	0.0000	0.0000	0.0000
28-358-11A/B	nC4 injection pumps	0.0000	0.0000	0.0000	0.0014	0.0330	0.0001	0.0000	0.0000	0.0000
Compressors		0.0000	0.0000							
11-358-1A/B	Ethane	19.0464	908.8282	0.0920	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
11-358-2A/B	Refrigeration	0.0000	34.1932	2.2636	0.0287	0.0026	0.0000	0.0000	0.0000	0.0000
11-358-3	C4 Splitter	0.0000	0.0000	0.0684	2.9339	0.0389	0.0000	0.0000	0.0000	0.0000
Emissions [4]		62.0102	2,032.8498	7.8765	3.7200	6.1677	2.3608	1.5543	0.1077	0.7569

[1] Emission calculations for C3 through C7 are based on a VOC content of 10,000 ppmv

[2] Uncontrolled Weight Per Hour for C1 and C2 (lb/hr) = Total Volume Rate (ft^3/hr) / 379.5 (scf/lb-mol) x Vapor Mass Fraction x Component Molecular Weight (lb/lb-mol)

Filter/Coalescers 15-358-1A/B C1 Weight Per Hour (lb/hr) = $\frac{51\ ft^3}{hr} \times \frac{lb\text{-}mol}{379.5\ scf} \times 0.063 \times \frac{16.043\ lb}{lb\text{-}mol}$ = 0.1371 lb/hr

Uncontrolled Weight Per Hour for C3 through C7 (lb/hr) = Total Volume Rate (ft^3/hr) / 379.5 (scf/lb-mol) x VOC Vapor Mass Fraction x Component Molecular Weight (lb/lb-mol) x VOC Concentration (ppmv) / 1,000,000

Filter/Coalescers 15-358-1A/B C3 Weight Per Hour (lb/hr) = $\frac{22\ ft^3}{hr} \times \frac{lb\text{-}mol}{379.5\ scf} \times 0.09 \times \frac{44.1\ lb}{lb\text{-}mol} \times \frac{10{,}000\ ppmv}{1{,}000{,}000}$ = 0.0056 lb/hr

[3] Uncontrolled Weight Per Year for C1 and C2 (lb/yr) = Uncontrolled Weight Per Hour (lb/hr) x Hours Per Event {hr/event) x Frequency per Year (event/yr)

Filter/Coalescers 15-358-1A/Bs C3 Weight Per Year (lb/yr) = $\frac{0.1371\ lb}{hr} \times \frac{1\ hr}{event} \times \frac{104\ event}{yr}$ = 14.25 lb/yr

Uncontrolled Weight Per Year (lb/yr) = Component Molecular Weight (lb/lb-mol) x Molar VOC Content (lb-mol/yr) x Vapor Mass Fraction

Filter/Coalescers 15-358-1A/Bs C3 Weight Per Year (lb/yr) = $\frac{44.1\ lb}{lb\text{-}mol} \times \frac{0.14\ lb\text{-}mol}{yr} \times 0.09$ = 0.59 lb/yr

[4] Hourly emissions are based on the maximum emissions of each of the filters/coalescers and compressors. The annual emissions (lb/yr) are the sum of the speciated emissions of all units.

FLR-5 Emission Factors [1]

Units	CO	NO_x	C1, C2, and C3 Flare Destruction Efficiency	C4+ Flare Destruction Efficiency
lb/MMBtu	0.2755	0.138	-	-
%	-	-	99%	98%

[1] Flare Emissions factors are from TCEQ Air Permits Division, *Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers,* RG-109 (Draft), October 2000, Table 4 (other, high Btu).

Start-up Emissions Summary

FIN	EPN	Source Name	Hourly Emissions (lb/hr) VOC [1]	Hourly Emissions (lb/hr) NO_x [2]	Hourly Emissions (lb/hr) CO [2]	Annual Emissions (tpy) VOC [1]	Annual Emissions (tpy) NO_x [3]	Annual Emissions (tpy) CO [3]
Startup	FLR-5	Startup Emissions to FLR-5	48.01	1.23	2.45	0.51	0.03	0.05

[1] VOC emissions calculated below.

[2] Hourly emissions of NO_x and CO based on the maximum hourly heating rate among all events.

Hourly Emissions of NO_x or CO (lb/hr) = Emission Factor (lb/MMBtu) x Gas Heating Rate (MMBtu/hr)

$$\text{Hourly Emissions of } NO_x \text{ (lb/hr)} = \frac{0.138 \text{ lb}}{\text{MMBtu}} \times \frac{4.42 \text{ MMBtu}}{\text{hr}} = 1.23 \text{ lb/hr}$$

[3] Annual Emissions (tpy) = Emission Factor (lb/MMBtu) x Σ (Hours per Event [hr/event] x Frequency per Year [event/yr] x Gas Heating Rate [MMBtu/hr])

Gas Heating Rates [1]

Speciated Gas	Higher Heating Value (Btu/ft^3)
C1	912
C2	1,699
C3	2,385
iC4	3105
C4	3,123
iC5	3,705
C5	3,714
C6	4,415
C7	4,415

[1] Per Table 5-7 of *Combined Heating, Cooling & Power Handbook: Technologies & Applications,* by Neil Petchers (2003)

Startup Parameters for Emissions to FLR-5

Unit ID	Description	Hours Per Event (hr/event)	Frequency per Year (event/yr)	ID (ft)	Height (ft)	Total Volume[1] (ft^3/event)	Total Volume Rate[2] (ft^3/hr)	Vapor Density (lb/ft^3)	Vapor Mass Fraction[3] C1	C2	C3	iC4	C4	iC5	C5	C6	C7+	Gas Heating Rate[4] (MMBtu/hr)
Pressure Vessels																		
31-358-1 Deeth	DC2	12	1	16	126	28,551	2,379	3.35	0.0323	0.7766	0.1329	0.0269	0.0199	0.0053	0.0033	0.0004	0.0025	4.42
30-358-1	DC2 Reflux Accum	12	1	10	50	4,712	393	7.72	0.0203	0.9699	0.0098	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.66
30-358-4	C2 Comp suct scrub	6	1	7	10	548	91	7.72	0.0203	0.9699	0.0098	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.15
30-358-6	Refrig comp suct scrub	6	1	8	10	905	151	1.50	0.0000	0.1297	0.8584	0.0109	0.0010	0.0000	0.0000	0.0000	0.0000	0.35
30-358-7	Refrig Accumulator	12	1	8	24	1,608	134	1.50	0.0000	0.1297	0.8584	0.0109	0.0010	0.0000	0.0000	0.0000	0.0000	0.31
31-358-4	DC3	12	1	13	114	16,857	1,405	0.83	0.0000	0.1079	0.6462	0.0800	0.1290	0.0183	0.0122	0.0009	0.0055	3.54
30-358-9	DC3 Reflux Accum	12	1	10	40	3,927	327	1.50	0.0000	0.1297	0.8584	0.0109	0.0010	0.0000	0.0000	0.0000	0.0000	0.75
30-358-401A/B	C3 COS Reactors	6	1	6	30	1,018	170	1.50	0.0000	0.1297	0.8584	0.0109	0.0010	0.0000	0.0000	0.0000	0.0000	0.39
30-358-402A/B	C3 H2S Reactors	6	1	7	34	1,578	263	1.50	0.0000	0.1297	0.8584	0.0109	0.0010	0.0000	0.0000	0.0000	0.0000	0.61
31-358-5	DC4	12	1	10	98	7,620	635	0.33	0.0000	0.0000	0.0069	0.3097	0.5389	0.0728	0.0480	0.0034	0.0203	2.04
30-358-10	DC4 Reflux accum	12	1	9	30	2,185	182	0.46	0.0000	0.0000	0.0079	0.3612	0.6294	0.0014	0.0000	0.0000	0.0000	0.57
31-358-6	C4 Splitter	12	1	12	212	25,334	2,111	0.46	0.0000	0.0000	0.0079	0.3612	0.6294	0.0014	0.0000	0.0000	0.0000	6.57
30-358-11	C4 Splitter comp K.O.	12	1	7	16	747	62	0.59	0.0000	0.0000	0.0225	0.9647	0.0128	0.0000	0.0000	0.0000	0.0000	0.19
30-358-12	C4 Splitter Reflux accum	12	1	9	40	2,752	229	0.46	0.0000	0.0000	0.0225	0.9647	0.0128	0.0000	0.0000	0.0000	0.0000	0.71
30-358-501A/B/C	Gasoline treaters	6	1	8	16	3,619	603	0.12	0.0000	0.0000	0.0000	0.0003	0.0230	0.4936	0.3272	0.0221	0.1338	2.30
30-358-502A/B/C	Caustic separators	6	1	6	20	2,205	368	0.12	0.0000	0.0000	0.0000	0.0003	0.0230	0.4936	0.3272	0.0221	0.1338	1.40
30-358-601A/B	Caustic Contactors	6	1	12	50	14,024	2,337	0.12	0.0000	0.0000	0.0000	0.0003	0.0230	0.4936	0.3272	0.0221	0.1338	8.89
30-358-602A/B	Caustic Settlers	6	1	6	30	2,036	339	0.12	0.0000	0.0000	0.0000	0.0003	0.0230	0.4936	0.3272	0.0221	0.1338	1.29
Pipelines																		
	RP	6	1	1	3,800	2,487	415	3.35	0.0323	0.7766	0.1329	0.0269	0.0199	0.0053	0.0033	0.0004	0.0025	0.77
	C2	6	1	1	3,800	2,487	415	7.72	0.0203	0.9699	0.0098	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.70
	C3	6	1	1	3,800	1,990	332	1.50	0.0000	0.1297	0.8584	0.0109	0.0010	0.0000	0.0000	0.0000	0.0000	0.76
	iC4	6	1	1	3,800	1,492	249	0.59	0.0000	0.0000	0.0225	0.9647	0.0128	0.0000	0.0000	0.0000	0.0000	0.77
	nC4	6	1	1	3,800	1,492	249	0.40	0.0000	0.0000	0.0000	0.0401	0.9576	0.0021	0.0001	0.0000	0.0000	0.78
	C5+	6	1	1	3,800	1,492	249	0.12	0.0000	0.0000	0.0000	0.0003	0.0230	0.4936	0.3272	0.0221	0.1338	0.95
Compressors																		
11-358-1A/B	Ethane	1	1	-	-	2,000	2,000	7.72	0.0203	0.9699	0.0098	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	3.38
11-358-2A/B	Refrigeration	2	1	-	-	1,200	600	1.50	0.0000	0.1297	0.8584	0.0109	0.0010	0.0000	0.0000	0.0000	0.0000	1.38
11-358-3	C4 Splitter	2	1	-	-	1,000	500	0.59	0.0000	0.0000	0.0225	0.9647	0.0128	0.0000	0.0000	0.0000	0.0000	1.54

[1] Total Volume (ft^3/event) = Pi * (ID (ft) / 2)^2 x Height (ft)

Pressure Vessel 31-358-1 Deeth C3 Total Volume (ft^3/event) = π | (16 ft / 2)^2 | 126 ft = 28,551 ft^3/event

[2] Total Volume Rate (ft^3/hr) = Total Volume (ft^3/event) / Hours Per Event (hr/event)

Pressure Vessel 31-358-1 Deeth C3 Total Volume Rate (ft^3/hr) = (28,551 ft3 / event) | (event / 12 hr) = 2,379 ft3/hr

[3] The mass fraction ratio of n-hexane to n-hexane and higher is 14.2 %

[4] Speciated Gas Heating Rate (MMBtu/hr) = Gas Volume Flow Rate (ft^3/hr) x Component Mass Fraction x Higher Heating Value (Btu/ft^3) x 1 MMBtu / 1,000,000 Btu

Startup Emissions to FLR-5

			Controlled Weight Per Hour (lb/hr) [1]									Controlled Weight Per Year (lb/yr) [2]								
Unit ID	**Description**	**Emission Groups**	**C1**	**C2**	**C3**	**iC4**	**C4**	**iC5**	**C5**	**C6**	**C7**	**C1**	**C2**	**C3**	**iC4**	**C4**	**iC5**	**C5**	**C6**	**C7**
Pressure Vessels																				
31-358-1 Deeth	DC2	A	2.57	61.80	10.58	4.29	3.16	0.84	0.52	0.07	0.40	30.83	741.64	126.92	51.47	37.92	10.05	6.23	0.79	4.80
30-358-1	DC2 Reflux Accum	A	0.62	29.40	0.30	1.60E-05	3.68E-07	3.68E-07	3.68E-07	5.22E-08	3.16E-07	7.39	352.79	3.57	1.92E-04	4.41E-06	4.41E-06	4.41E-06	6.27E-07	3.79E-06
30-358-4	C2 Comp suct scrub	A	0.14	6.83	0.07	3.71E-06	8.55E-08	8.55E-08	8.55E-08	1.21E-08	7.33E-08	0.86	40.99	0.41	2.23E-05	5.13E-07	5.13E-07	5.13E-07	7.28E-08	4.40E-07
30-358-6	Refrig comp suct scrub	B	1.61E-08	0.29	1.94	0.05	4.51E-03	7.45E-08	7.45E-08	1.06E-08	6.40E-08	9.65E-08	1.75	11.61	0.29	0.03	4.47E-07	4.47E-07	6.35E-08	3.84E-07
30-358-7	Refrig Accumulator	B	1.43E-08	0.26	1.72	0.04	4.01E-03	6.63E-08	6.63E-08	9.41E-09	5.68E-08	1.72E-07	3.12	20.64	0.52	0.05	7.95E-07	7.95E-07	1.13E-07	6.82E-07
31-358-4	DC3	C	7.97E-08	1.26	7.55	1.87	3.02	0.43	0.29	0.02	0.13	9.57E-07	15.13	90.65	22.44	36.20	5.12	3.43	0.26	1.55
30-358-9	DC3 Reflux Accum	C	3.49E-08	0.63	4.20	0.11	9.80E-03	1.62E-07	1.62E-07	2.30E-08	1.39E-07	4.19E-07	7.61	50.40	1.28	0.12	1.94E-06	1.94E-06	2.76E-07	1.67E-06
30-358-401A/B	C3 COS Reactors	D	1.81E-08	0.33	2.18	0.06	5.08E-03	8.39E-08	8.39E-08	1.19E-08	7.19E-08	1.09E-07	1.97	13.06	0.33	0.03	5.03E-07	5.03E-07	7.14E-08	4.32E-07
30-358-402A/B	C3 H2S Reactors	D	2.80E-08	0.51	3.37	0.09	7.87E-03	1.30E-07	1.30E-07	1.85E-08	1.12E-07	1.68E-07	3.06	20.25	0.51	0.05	7.80E-07	7.80E-07	1.11E-07	6.69E-07
31-358-5	DC4	E	6.94E-25	1.62E-09	0.01	1.28	2.23	0.30	0.20	0.01	0.08	8.33E-24	1.95E-08	0.17	15.34	26.70	3.61	2.38	0.17	1.00
30-358-10	DC4 Reflux accum	E	3.02E-25	3.02E-25	6.56E-03	0.60	1.04	2.32E-03	7.66E-05	5.84E-12	3.53E-11	3.62E-24	3.62E-24	0.08	7.19	12.53	0.03	9.19E-04	7.00E-11	4.23E-10
31-358-6	C4 Splitter	E	3.50E-24	3.50E-24	0.08	6.95	12.11	0.03	8.88E-04	6.77E-11	4.09E-10	4.20E-23	4.20E-23	0.91	83.38	145.30	0.32	0.01	8.12E-10	4.91E-09
30-358-11	C4 Splitter comp K.O.	E	1.35E-25	1.35E-25	8.31E-03	0.71	9.46E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.61E-24	1.61E-24	0.10	8.55	0.11	0.00E+00	0.00E+00	0.00E+00	0.00E+00
30-358-12	C4 Splitter Reflux accum	E	3.81E-25	3.81E-25	0.02	2.02	0.03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.57E-24	4.57E-24	0.28	24.19	0.32	0.00E+00	0.00E+00	0.00E+00	0.00E+00
30-358-501A/B/C	Gasoline treaters	E	0.00E+00	1.98E-24	6.14E-11	3.78E-04	0.03	0.71	0.47	0.03	0.19	0.00E+00	1.19E-23	3.68E-10	2.27E-03	0.20	4.24	2.81	0.19	1.15
30-358-502A/B/C	Caustic separators	E	0.00E+00	1.21E-24	3.74E-11	2.30E-04	0.02	0.43	0.29	0.02	0.12	0.00E+00	7.24E-24	2.24E-10	1.38E-03	0.12	2.58	1.71	0.12	0.70
30-358-601A/B	Caustic Contactors	E	0.00E+00	7.68E-24	2.38E-10	1.46E-03	0.13	2.74	1.82	0.12	0.74	0.00E+00	4.61E-23	1.43E-09	8.79E-03	0.76	16.43	10.89	0.74	4.45
30-358-602A/B	Caustic Settlers	E	0.00E+00	1.11E-24	3.45E-11	2.13E-04	0.02	0.40	0.26	0.02	0.11	0.00E+00	6.69E-24	2.07E-10	1.28E-03	0.11	2.39	1.58	0.11	0.65
Pipelines																				
	RP	-	0.45	10.77	1.84	0.75	0.55	0.15	0.09	0.01	0.07	2.69	64.60	11.06	4.48	3.30	0.88	0.54	0.07	0.42
	C2	-	0.65	31.03	0.31	1.69E-05	3.88E-07	3.88E-07	3.88E-07	5.51E-08	3.33E-07	3.90	186.19	1.88	1.01E-04	2.33E-06	2.33E-06	2.33E-06	3.31E-07	2.00E-06
	C3	-	3.54E-08	0.64	4.26	0.11	9.93E-03	1.64E-07	1.64E-07	2.33E-08	1.41E-07	2.12E-07	3.86	25.53	0.65	0.06	9.83E-07	9.83E-07	1.40E-07	8.44E-07
	iC4	-	5.38E-25	5.38E-25	0.03	2.85	0.04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.23E-24	3.23E-24	0.20	17.10	0.23	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	nC4	-	0.00E+00	0.00E+00	0.00E+00	0.08	1.92	4.22E-03	2.01E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.48	11.55	0.03	1.21E-03	0.00E+00	0.00E+00
	C5+	-	0.00E+00	8.17E-25	2.53E-11	1.56E-04	0.01	0.29	0.19	0.01	0.08	0.00E+00	4.90E-24	1.52E-10	9.35E-04	0.08	1.75	1.16	0.08	0.47
Compressors																				
11-358-1A/B	Ethane	-	3.14	149.73	1.52	8.14E-05	1.87E-06	1.87E-06	1.87E-06	2.66E-07	1.61E-06	3.14	149.73	1.52	8.14E-05	1.87E-06	1.87E-06	1.87E-06	2.66E-07	1.61E-06
11-358-2A/B	Refrigeration	-	6.40E-08	1.16	7.70	0.20	0.02	2.97E-07	2.97E-07	4.21E-08	2.54E-07	1.28E-07	2.33	15.40	0.39	0.04	5.93E-07	5.93E-07	8.42E-08	5.09E-07
11-358-3	C4 Splitter	-	1.08E-24	1.08E-24	0.07	5.73	0.08	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.16E-24	2.16E-24	0.13	11.46	0.15	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Emissions [3]			3.33	149.73	11.75	11.56	15.61	4.60	3.03	0.21	1.24	48.81	1,574.77	394.78	250.10	275.96	47.42	30.75	2.51	15.19

[1] Controlled Weight Per Hour (lb/hr) = Total Volume Rate (ft3/hr) x Vapor Density (lb/ft3) x Component Vapor Mass Fraction x (100-(Flare Destruction Factor (%))/100

Pressure Vessel 31-358-1 Deeth C3 Weight Per Hour (lb/hr) = $\frac{2,379\ ft3}{hr} \times \frac{3.35\ lb}{ft^3} \times 0.13 \times \frac{100-99\%}{100}$ = 10.58 lb/hr

[2] Controlled Weight Per Year (lb/yr) = Total Volume (ft3) x Vapor Density (lb/ft3) x Component Vapor Mass Fraction x Frequency/Year x (100-(Flare Destruction Factor (%))/100

Pressure Vessel 31-358-1 Deeth C3 Weight Per Year (lb/yr) = $28,551\ ft3 \times \frac{3.35\ lb}{ft^3} \times 0.13 \times \frac{1\ event}{yr} \times \frac{100-99\%}{100}$ = 126.92 lb/yr

[3] Each of the pipelines, compressors, and pressure vessels groups occur at separate instances. Therefore, hourly emissions are based on the maximum emissions for the sum of the emissions of Group A, B, C, D, E and each of the remaining units. The annual emissions (lb/yr) are the sum of the speciated emissions of all units.

Targa Midstream Services LLC - Mont Belvieu Plant
Shutdown Emissions Sent to FLR-5

FLR-5 Emission Factors [1]

Units	CO	NO_x	C1, C2, and C3 Flare Destruction Efficiency	C4+ Flare Destruction Efficiency
lb/MMBtu	0.2755	0.138	-	-
%	-	-	99%	98%

[1] Flare Emissions factors are from TCEQ Air Permits Division, *Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers,* RG-109 (Draft), October 2000, Table 4 (other, high Btu).

Shutdown FLR-5 Emissions Summary

FIN	EPN	Source Name	Hourly Emissions (lb/hr) VOC [1]	NO_x [2]	CO [2]	Annual Emissions (tpy) VOC [1]	NO_x [3]	CO [3]
Shutdown	FLR-5	Shutdown Emissions to FLR-5	43.68	2.35	4.69	0.99	0.03	0.05

[1] VOC missions calculated below.
[2] Hourly emissions of NO_x and CO based on the maximum heating rate among the sum of the heating rates for Group F, G, H, I, J, K, L, and each of the remaining units.
Hourly Emissions of NO_x or CO (lb/hr) = Emission Factor (lb/MMBtu) x Gas Heating Rate (MMBtu/hr)

Hourly Emissions of NO_x (lb/hr) = 0.138 lb / MMBtu | 6.57 MMBtu / hr = 2.35 lb/hr

[3] NO_x and CO Annual Emissions (tpy) =Flare Emissions Factor (lb/dscf) x Sum of the Product (Total Volume of Emissions (ft^3/event) x Total Frequency (1/yr)) Per Each Equipment x 1 ton / 2,000 lb

Gas Heating Rate [1]

Speciated Gas	Higher Heating Value (Btu/ft^3)
C1	912
C2	1,699
C3	2,385
iC4	3105
C4	3,123
iC5	3,705
C5	3,714
C6	4,415
C7	4,415

[1] Per Table 5-7 of *Combined Heating, Cooling & Power Handbook: Technologies & Applications,* by Neil Petchers (2003)

Targa Midstream Services LLC - Mont Belvieu Plant
Shutdown Emissions Sent to FLR-5

Shutdown Liquid Parameters Sent to FLR-5

Unit ID	Description	Hours Per Event (hr/event)	Frequency per Year (event/yr)	ID (ft)	Height (ft)	Total Volume [1] (ft^3/event)	Total Volume Rate [2] (ft^3/hr)	Heel (ft)	Heel Volume [3] (ft^3/event)	Heel Volume Rate [2] (ft^3/hr)	Liquid Density (lb/ft^3)	Component Liquid Mass Fraction [4] C1	C2	C3	iC4	C4	iC5	C5	C6	C7	Gas Heating Rate [4] (MMBtu/hr)
Pressure Vessels																					
31-358-1 Deeth	DC2	12	1	16	126	28,551	2,379	2	402	34	27.23	6.40E-03	0.51	0.21	0.08	0.08	0.04	0.03	7.93E-03	0.05	0.0785
30-358-1	DC2 Reflux Accum	12	1	10	50	4,712	393	0.5	39	3	17.03	0.01	0.97	0.01	4.98E-07	1.26E-08	3.56E-13	1.35E-14	1.81E-20	1.09E-19	0.0056
30-358-4	C2 Comp suct scrub	12	1	6.5	10	548	46	0.5	17	1	17.03	0.01	0.97	0.01	4.98E-07	1.26E-08	3.56E-13	1.35E-14	1.81E-20	1.09E-19	0.0023
30-358-6	Refrig comp suct scrub	12	1	8	10	905	75	0.5	25	2	30.27	6.01E-10	0.05	0.92	0.03	3.14E-03	1.13E-07	1.13E-07	1.60E-08	9.69E-08	0.0050
30-358-7	Refrig Accumulator	12	1	8	24	1,608	134	0.5	25	2	30.27	6.01E-10	0.05	0.92	0.03	3.14E-03	1.13E-07	1.13E-07	1.60E-08	9.69E-08	0.0050
31-358-4	DC3	12	1	13	114	16,857	1,405	2	265	22	34.32	2.43E-10	0.02	0.37	0.11	0.24	0.08	0.07	0.02	0.09	0.0673
30-358-9	DC3 Reflux Accum	12	1	10	40	3,927	327	0.5	39	3	30.27	6.01E-10	0.05	0.92	0.03	3.14E-03	1.13E-07	1.13E-07	1.60E-08	9.69E-08	0.0078
30-358-401A/B	C3 COS Reactors	6	1	6	30	1,018	170	0.5	14	2	30.27	6.01E-10	0.05	0.92	0.03	3.14E-03	1.13E-07	1.13E-07	1.60E-08	9.69E-08	0.0056
30-358-402A/B	C3 H2S Reactors	6	1	7	34	1,578	263	0.5	19	3	30.27	6.01E-10	0.05	0.92	0.03	3.14E-03	1.13E-07	1.13E-07	1.60E-08	9.69E-08	0.0076
31-358-5	DC4	12	1	9.5	98	7,620	635	2	142	12	37.05	3.82E-27	4.82E-11	1.49E-03	0.17	0.40	0.13	0.12	0.03	0.15	0.0413
30-358-10	DC4 Reflux accum	12	1	8.5	30	2,185	182	0.5	28	2	35.24	6.71E-27	8.47E-11	2.62E-03	0.29	0.70	3.78E-03	1.64E-04	3.81E-11	2.30E-10	0.0074
31-358-6	C4 Splitter	12	1	12	212	25,334	2,111	2	226	19	35.24	6.71E-27	8.47E-11	2.62E-03	0.29	0.70	3.78E-03	1.64E-04	3.81E-11	2.30E-10	0.0588
30-358-11	C4 Splitter comp K.O.	12	1	6.5	16	747	62	0.5	17	1	34.22	2.43E-26	3.06E-10	9.46E-03	0.97	0.02	8.82E-17	1.29E-21	1.76E-31	1.06E-30	0.0043
30-358-12	C4 Splitter Reflux accum.	12	1	8.5	40	2,752	229	0.5	28	2	34.22	2.43E-26	3.06E-10	9.46E-03	0.97	0.02	8.82E-17	1.29E-21	1.76E-31	1.06E-30	0.0073
30-358-501A/B/C	Gasoline treaters	12	1	8	16	3,619	302	0.5	25	2	39.49	2.08E-31	5.24E-26	5.88E-12	4.59E-05	5.64E-03	0.31	0.27	0.06	0.36	0.0084
30-358-502A/B/C	Caustic separators	12	1	6	20	2,205	184	0.5	14	1	39.49	2.08E-31	5.24E-26	5.88E-12	4.59E-05	5.64E-03	0.31	0.27	0.06	0.36	0.0047
30-358-601A/B	Caustic Contactors	12	1	12	50	14,024	1,169	0.5	57	5	39.49	2.08E-31	5.24E-26	5.88E-12	4.59E-05	5.64E-03	0.31	0.27	0.06	0.36	0.0188
30-358-602A/B	Caustic Settlers	12	1	6	30	2,036	170	0.5	14	1	39.49	2.08E-31	5.24E-26	5.88E-12	4.59E-05	5.64E-03	0.31	0.27	0.06	0.36	0.0047
Pipelines																					
	RP	12	1	0.83	3,800	2,487	207	0.05	124	10	27.23	6.40E-03	0.51	0.21	0.08	0.08	0.04	0.03	7.93E-03	0.05	0.0243
	C2	12	1	0.83	3,800	2,487	207	0.05	124	10	17.03	0.01	0.97	0.01	4.98E-07	1.26E-08	3.56E-13	1.35E-14	1.81E-20	1.09E-19	0.0176
	C3	12	1	0.67	3,800	1,990	166	0.05	99	8	30.27	6.01E-10	0.05	0.92	0.03	3.14E-03	1.13E-07	1.13E-07	1.60E-08	9.69E-08	0.0197
	iC4	12	1	0.5	3,800	1,492	124	0.05	75	6	34.22	2.43E-26	3.06E-10	9.46E-03	0.97	0.02	8.82E-17	1.29E-21	1.76E-31	1.06E-30	0.0193
	nC4	12	1	0.5	3,800	1,492	124	0.05	75	6	35.62	2.76E-31	5.17E-31	1.27E-19	0.03	0.97	5.23E-03	2.27E-04	5.26E-11	3.18E-10	0.0194
	C5+	12	1	0.5	3,800	1,492	124	0.05	75	6	39.49	2.08E-31	5.24E-26	5.88E-12	4.59E-05	5.64E-03	0.31	0.27	0.06	0.36	0.0249
Filters/Coalescers																					
15-358-1A/B	Plant inlet feed filters	2	1	3	7.25	51	26	0.5	4	2	27.23	6.40E-03	0.51	0.21	0.08	0.08	0.04	0.03	7.93E-03	0.05	0.0041
15-358-2A/B	Plant feed inlet coalescers	2	1	5	5.25	103	52	0.5	10	5	27.23	6.40E-03	0.51	0.21	0.08	0.08	0.04	0.03	7.93E-03	0.05	0.0115
15-358-401	Treated Propane Filter Coalescer	2	1	3	5.25	37	19	0.5	4	2	30.27	6.01E-10	0.05	0.92	0.03	3.14E-03	1.13E-07	1.13E-07	1.60E-08	9.69E-08	0.0042
15-358-501	Treated gasoline coalescer	2	1	2.33	5.25	22	11	0.5	2	1	39.49	2.08E-31	5.24E-26	5.88E-12	4.59E-05	5.64E-03	0.31	0.27	0.06	0.36	0.0043
15-358-601	n-butane product coalescer	2	1	3	5.25	37	19	0.5	4	2	35.62	2.76E-31	5.17E-31	1.27E-19	0.03	0.97	5.23E-03	2.27E-04	5.26E-11	3.18E-10	0.0055
Pumps																					
28-358-1A/B	DC2 Reflux Pumps	2	1	-	-	11.24	6	-	-	-	17.03	0.01	0.97	0.01	4.98E-07	1.26E-08	3.56E-13	1.35E-14	1.81E-20	1.09E-19	0.0095
28-358-2A/B	DC3 Reflux Pumps	2	1	-	-	11.24	6	-	-	-	30.27	6.01E-10	0.05	0.92	0.03	3.14E-03	1.13E-07	1.13E-07	1.60E-08	9.69E-08	0.0133
28-358-3A/B	C3 Inject pumps	2	1	-	-	11.24	6	-	-	-	30.27	6.01E-10	0.05	0.92	0.03	3.14E-03	1.13E-07	1.13E-07	1.60E-08	9.69E-08	0.0133
28-358-4A/B	DC4 Reflux pumps	2	1	-	-	11.24	6	-	-	-	35.24	6.71E-27	8.47E-11	2.62E-03	0.29	0.70	3.78E-03	1.64E-04	3.81E-11	2.30E-10	0.0175
28-358-5A/B	Gasoline booster pumps	2	1	-	-	11.24	6	-	-	-	39.49	2.08E-31	5.24E-26	5.88E-12	4.59E-05	5.64E-03	0.31	0.27	0.06	0.36	0.0225
28-358-6A/B	Gasoline injection pumps	2	1	-	-	11.24	6	-	-	-	39.49	2.08E-31	5.24E-26	5.88E-12	4.59E-05	5.64E-03	0.31	0.27	0.06	0.36	0.0225
28-358-7A/B	C4 split bottoms pumps	2	1	-	-	11.24	6	-	-	-	34.22	2.43E-26	3.06E-10	9.46E-03	0.97	0.02	8.82E-17	1.29E-21	1.76E-31	1.06E-30	0.0174
28-358-8A/B	C4 split reflux pumps	2	1	-	-	11.24	6	-	-	-	35.62	2.76E-31	5.17E-31	1.27E-19	0.03	0.97	5.23E-03	2.27E-04	5.26E-11	3.18E-10	0.0176
28-358-9A/B	C4 Split comp K.O. drum pumps	2	1	-	-	11.24	6	-	-	-	34.22	2.43E-26	3.06E-10	9.46E-03	0.97	0.02	8.82E-17	1.29E-21	1.76E-31	1.06E-30	0.0174
28-358-10A/B	iC4 injection pumps	2	1	-	-	11.24	6	-	-	-	34.22	2.43E-26	3.06E-10	9.46E-03	0.97	0.02	8.82E-17	1.29E-21	1.76E-31	1.06E-30	0.0174
28-358-11A/B	nC4 injection pumps	2	1	-	-	11.24	6	-	-	-	35.62	2.76E-31	5.17E-31	1.27E-19	0.03	0.97	5.23E-03	2.27E-04	5.26E-11	3.18E-10	0.0176

[1] Total Volume (ft^3/event) = Pi x (ID (ft) / 2)^2 x Height (ft)

Pressure Vessel 31-358-1 Deeth C3 Total Volume (ft^3/event) = π | (16 ft / 2)^2 | 126 ft = 28,551 ft3/event

[2] Total Volume Rate or Heel Volume Rate (ft^3/hr) = Total Volume or Heel Volume (ft^3/event) / Hours Per Event (hr/event)

Pressure Vessel 31-358-1 Deeth C3 Total Volume Rate (ft^3/hr) = 28,551 ft3 / event | event / 12 hr = 2,379 ft3/hr

[3] Heel Volume (ft^3/event) = Pi x (ID (ft)/2)^2 x Heel (ft)

Pressure Vessel 31-358-1 Deeth C3 Heel Volume (ft^3/event) = π | (16 ft / 2)^2 | 2 ft = 3,927 ft3/event

[4] The mass fraction ratio of n-hexane to n-hexane and higher is 14.2 %

Shutdown Liquid Emissions Sent to FLR-5

Unit ID	Description	Emission Groups	Weight Per Hour (lb/hr) [1] C1	C2	C3	iC4	C4	iC5	C5	C6	C7
Pressure Vessels											
31-358-1 Deeth	DC2	F	0.06	4.62	1.92	1.47	1.37	0.68	0.51	0.14	0.87
30-358-1	DC2 Reflux Accum	F	6.96E-03	0.54	7.92E-03	5.55E-07	1.40E-08	3.97E-13	1.51E-14	2.02E-20	1.22E-19
30-358-4	C2 Comp suct scrub	F	2.94E-03	0.23	3.35E-03	2.34E-07	5.93E-09	1.68E-13	6.38E-15	8.52E-21	5.15E-20
30-358-6	Refrig comp suct scrub	F	3.81E-10	0.03	0.59	0.03	3.98E-03	1.43E-07	1.43E-07	2.03E-08	1.23E-07
30-358-7	Refrig Accumulator	F	3.81E-10	0.03	0.59	0.03	3.98E-03	1.43E-07	1.43E-07	2.03E-08	1.23E-07
31-358-4	DC3	F	1.84E-09	0.14	2.84	1.65	3.67	1.21	1.06	0.23	1.39
30-358-9	DC3 Reflux Accum	F	5.96E-10	0.05	0.92	0.05	6.22E-03	2.24E-07	2.24E-07	3.18E-08	1.92E-07
30-358-401A/B	C3 COS Reactors	F	4.29E-10	0.03	0.66	0.04	4.48E-03	1.61E-07	1.61E-07	2.29E-08	1.38E-07
30-358-402A/B	C3 H2S Reactors	F	5.84E-10	0.05	0.90	0.05	6.10E-03	2.19E-07	2.19E-07	3.11E-08	1.88E-07
31-358-5	DC4	G	1.67E-26	2.11E-10	6.52E-03	1.45	3.53	1.17	1.02	0.22	1.35
30-358-10	DC4 Reflux accum	G	5.59E-27	7.06E-11	2.18E-03	0.48	1.17	6.30E-03	2.73E-04	6.34E-11	3.83E-10
31-358-6	C4 Splitter	G	4.46E-26	5.63E-10	0.02	3.85	9.34	0.05	2.18E-03	5.06E-10	3.06E-09
30-358-11	C4 Splitter comp K.O.	G	1.15E-26	1.45E-10	4.47E-03	0.92	0.02	8.34E-17	1.22E-21	1.66E-31	1.00E-30
30-358-12	C4 Splitter Reflux accum.	G	1.96E-26	2.48E-10	7.65E-03	1.57	0.03	1.43E-16	2.09E-21	2.84E-31	1.72E-30
30-358-501A/B/C	Gasoline treaters	G	1.72E-31	4.33E-26	4.86E-12	7.59E-05	9.34E-03	0.51	0.45	0.10	0.59
30-358-502A/B/C	Caustic separators	G	9.66E-32	2.44E-26	2.73E-12	4.27E-05	5.25E-03	0.29	0.25	0.06	0.33
30-358-601A/B	Caustic Contactors	G	3.86E-31	9.75E-26	1.09E-11	1.71E-04	0.02	1.14	1.01	0.22	1.33
30-358-602A/B	Caustic Settlers	G	9.66E-32	2.44E-26	2.73E-12	4.27E-05	5.25E-03	0.29	0.25	0.06	0.33
Pipelines											
	RP	-	0.02	1.43	0.59	0.45	0.42	0.21	0.16	0.04	0.27
	C2	-	0.02	1.72	0.03	1.76E-06	4.45E-08	1.26E-12	4.78E-14	6.39E-20	3.86E-19
	C3	-	1.51E-09	0.12	2.32	0.13	0.02	5.67E-07	5.67E-07	8.05E-08	4.87E-07
	iC4	-	5.16E-26	6.51E-10	0.02	4.14	0.08	3.75E-16	5.50E-21	7.47E-31	4.51E-30
	nC4	-	6.10E-31	1.14E-30	2.82E-19	0.13	4.28	0.02	1.00E-03	2.33E-10	1.41E-09
	C5+	-	5.10E-31	1.29E-25	1.44E-11	2.25E-04	0.03	1.50	1.33	0.29	1.76
Filters/Coalescers											
15-358-1A/B	Plant inlet feed filters	-	3.08E-03	0.24	0.10	0.08	0.07	0.04	0.03	7.63E-03	0.05
15-358-2A/B	Plant feed inlet coalescers	-	8.55E-03	0.68	0.28	0.21	0.20	0.10	0.08	0.02	0.13
15-358-401	Treated Propane Filter Coalescer	-	3.22E-10	0.03	0.49	0.03	3.36E-03	1.21E-07	1.21E-07	1.72E-08	1.04E-07
15-358-501	Treated gasoline coalescer	-	8.76E-32	2.21E-26	2.48E-12	3.87E-05	4.76E-03	0.26	0.23	0.05	0.30
15-358-601	n-butane product coalescer	-	1.73E-31	3.25E-31	8.00E-20	0.04	1.22	6.58E-03	2.86E-04	6.63E-11	4.00E-10
Pumps											
28-358-1A/B	DC2 Reflux Pumps	-	0.01	0.93	0.01	9.53E-07	2.41E-08	6.82E-13	2.59E-14	3.46E-20	2.09E-19
28-358-2A/B	DC3 Reflux Pumps	-	1.02E-09	0.08	1.57	0.09	0.01	3.84E-07	3.84E-07	5.46E-08	3.30E-07
28-358-3A/B	C3 Inject pumps	-	1.02E-09	0.08	1.57	0.09	0.01	3.84E-07	3.84E-07	5.46E-08	3.30E-07
28-358-4A/B	DC4 Reflux pumps	-	1.33E-26	1.68E-10	5.18E-03	1.15	2.78	0.01	6.50E-04	1.51E-10	9.11E-10
28-358-5A/B	Gasoline booster pumps	-	4.61E-31	1.16E-25	1.30E-11	2.04E-04	0.03	1.36	1.20	0.26	1.59
28-358-6A/B	Gasoline injection pumps	-	4.61E-31	1.16E-25	1.30E-11	2.04E-04	0.03	1.36	1.20	0.26	1.59
28-358-7A/B	C4 split bottoms pumps	-	4.66E-26	5.88E-10	0.02	3.74	0.07	3.39E-16	4.97E-21	6.75E-31	4.08E-30
28-358-8A/B	C4 split reflux pumps	-	5.52E-31	1.03E-30	2.54E-19	0.12	3.86	0.02	9.08E-04	2.11E-10	1.27E-09
28-358-9A/B	C4 Split comp K.O. drum pumps	-	4.66E-26	5.88E-10	0.02	3.74	0.07	3.39E-16	4.97E-21	6.75E-31	4.08E-30
28-358-10A/B	iC4 injection pumps	-	4.66E-26	5.88E-10	0.02	3.74	0.07	3.39E-16	4.97E-21	6.75E-31	4.08E-30
28-358-11A/B	nC4 injection pumps	-	5.52E-31	1.03E-30	2.54E-19	0.12	3.86	0.02	9.08E-04	2.11E-10	1.27E-09
Emissions [3]			0.07	5.73	8.41	8.28	14.13	3.45	2.99	0.65	3.94

Unit ID	Description	Emission Groups	Weight Per Year (lb/yr) [2] C1	C2	C3	iC4	C4	iC5	C5	C6	C7
Pressure Vessels											
31-358-1 Deeth	DC2	F	0.70	55.49	23.01	17.59	16.42	8.18	6.16	1.74	10.50
30-358-1	DC2 Reflux Accum	F	0.08	6.51	0.10	6.66E-06	1.69E-07	4.77E-12	1.81E-13	2.42E-19	1.46E-18
30-358-4	C2 Comp suct scrub	F	0.04	2.75	0.04	2.81E-06	7.12E-08	2.01E-12	7.65E-14	1.02E-19	6.18E-19
30-358-6	Refrig comp suct scrub	F	4.58E-09	0.36	7.03	0.39	0.05	1.72E-06	1.72E-06	2.44E-07	1.47E-06
30-358-7	Refrig Accumulator	F	4.58E-09	0.36	7.03	0.39	0.05	1.72E-06	1.72E-06	2.44E-07	1.47E-06
31-358-4	DC3	F	2.21E-08	1.73	34.07	19.83	44.00	14.57	12.70	2.77	16.73
30-358-9	DC3 Reflux Accum	F	7.15E-09	0.56	10.99	0.61	0.07	2.69E-06	2.69E-06	3.81E-07	2.30E-06
30-358-401A/B	C3 COS Reactors	F	2.57E-09	0.20	3.95	0.22	0.03	9.67E-07	9.67E-07	1.37E-07	8.30E-07
30-358-402A/B	C3 H2S Reactors	F	3.50E-09	0.27	5.38	0.30	0.04	1.32E-06	1.32E-06	1.87E-07	1.13E-06
31-358-5	DC4	G	2.01E-25	2.53E-09	0.08	17.35	42.31	14.09	12.28	2.68	16.18
30-358-10	DC4 Reflux accum	G	6.71E-26	8.47E-10	0.03	5.80	14.06	0.08	3.28E-03	7.61E-10	4.60E-09
31-358-6	C4 Splitter	G	5.35E-25	6.75E-09	0.21	46.25	112.12	0.60	0.03	6.07E-09	3.67E-08
30-358-11	C4 Splitter comp K.O.	G	1.38E-25	1.74E-09	0.05	11.05	0.20	1.00E-15	1.47E-20	1.99E-30	1.20E-29
30-358-12	C4 Splitter Reflux accum.	G	2.35E-25	2.97E-09	0.09	18.89	0.34	1.71E-15	2.51E-20	3.41E-30	2.06E-29
30-358-501A/B/C	Gasoline treaters	G	2.06E-30	5.20E-25	5.83E-11	9.11E-04	0.11	6.08	5.38	1.17	7.10
30-358-502A/B/C	Caustic separators	G	1.16E-30	2.92E-25	3.28E-11	5.12E-04	0.06	3.42	3.03	0.66	3.99
30-358-601A/B	Caustic Contactors	G	4.64E-30	1.17E-24	1.31E-10	2.05E-03	0.25	13.69	12.11	2.64	15.97
30-358-602A/B	Caustic Settlers	G	1.16E-30	2.92E-25	3.28E-11	5.12E-04	0.06	3.42	3.03	0.66	3.99
Pipelines											
	RP	-	0.22	17.16	7.11	5.44	5.08	2.53	1.91	0.54	3.25
	C2	-	0.26	20.61	0.30	2.11E-05	5.34E-07	1.51E-11	5.74E-13	7.66E-19	4.63E-18
	C3	-	1.81E-08	1.42	27.83	1.54	0.19	6.80E-06	6.80E-06	9.66E-07	5.84E-06
	iC4	-	6.19E-25	7.81E-09	0.24	49.68	0.90	4.50E-15	6.60E-20	8.96E-30	5.42E-29
	nC4	-	7.32E-30	1.37E-29	3.38E-18	1.54	51.33	0.28	0.01	2.80E-09	1.69E-08
	C5+	-	6.12E-30	1.54E-24	1.73E-10	2.70E-03	0.33	18.06	15.98	3.49	21.07
Filters/Coalescers											
15-358-1A/B	Plant inlet feed filters	-	6.16E-03	0.49	0.20	0.15	0.14	0.07	0.05	0.02	0.09
15-358-2A/B	Plant feed inlet coalescers	-	0.02	1.35	0.56	0.43	0.40	0.20	0.15	0.04	0.26
15-358-401	Treated Propane Filter Coalescer	-	6.43E-10	0.05	0.99	0.05	6.72E-03	2.42E-07	2.42E-07	3.43E-08	2.07E-07
15-358-501	Treated gasoline coalescer	-	1.75E-31	4.42E-26	4.96E-12	7.75E-05	9.53E-03	0.52	0.46	0.10	0.60
15-358-601	n-butane product coalescer	-	3.47E-31	6.51E-31	1.60E-19	0.07	2.43	0.01	5.71E-04	1.33E-10	8.01E-10
Pumps											
28-358-1A/B	DC2 Reflux Pumps	-	0.02	1.86	0.03	1.91E-06	4.82E-08	1.36E-12	5.18E-14	6.92E-20	4.18E-19
28-358-2A/B	DC3 Reflux Pumps	-	2.05E-09	0.16	3.14	0.17	0.02	7.68E-07	7.68E-07	1.09E-07	6.59E-07
28-358-3A/B	C3 Inject pumps	-	2.05E-09	0.16	3.14	0.17	0.02	7.68E-07	7.68E-07	1.09E-07	6.59E-07
28-358-4A/B	DC4 Reflux pumps	-	2.66E-26	3.35E-10	0.01	2.30	5.57	0.03	1.30E-03	3.01E-10	1.82E-09
28-358-5A/B	Gasoline booster pumps	-	9.21E-31	2.32E-25	2.61E-11	4.07E-04	0.05	2.72	2.41	0.53	3.17
28-358-6A/B	Gasoline injection pumps	-	9.21E-31	2.32E-25	2.61E-11	4.07E-04	0.05	2.72	2.41	0.53	3.17
28-358-7A/B	C4 split bottoms pumps	-	9.33E-26	1.18E-09	0.04	7.48	0.14	6.78E-16	9.93E-21	1.35E-30	8.16E-30
28-358-8A/B	C4 split reflux pumps	-	1.10E-30	2.07E-30	5.09E-19	0.23	7.73	0.04	1.82E-03	4.21E-10	2.55E-09
28-358-9A/B	C4 Split comp K.O. drum pumps	-	9.33E-26	1.18E-09	0.04	7.48	0.14	6.78E-16	9.93E-21	1.35E-30	8.16E-30
28-358-10A/B	iC4 injection pumps	-	9.33E-26	1.18E-09	0.04	7.48	0.14	6.78E-16	9.93E-21	1.35E-30	8.16E-30
28-358-11A/B	nC4 injection pumps	-	1.10E-30	2.07E-30	5.09E-19	0.23	7.73	0.04	1.82E-03	4.21E-10	2.55E-09
Emissions [3]			1.35	111.51	135.73	223.14	312.59	91.36	78.10	17.56	106.08

[1] Controlled Weight Per Hour (lb/hr) = Total or Heel Volume Rate (ft^3/hr) x Liquid Density (lb/ft^3) x Component Vapor Mass Fraction x (100-(Flare Destruction Factor (%))/100

Pressure Vessel 31-358-1 Deeth C3 Weight Per Hour (lb/hr) = $\frac{34\ ft3}{hr} \times \frac{27.23\ lb}{ft^3} \times 0.21 \times \frac{100-99\%}{100}$ = 1.92 lb/hr

[2] Controlled Weight Per Year (lb/yr) = Total Volume (ft^3) x Liquid Density (lb/ft^3) x Component Vapor Mass Fraction x Frequency/Year x (100-(Flare Destruction Factor (%))/100

Pressure Vessel 31-358-1 Deeth C3 Weight Per Year (lb/yr) = $28{,}551\ ft3 \times \frac{27.23\ lb}{ft^3} \times 0.21 \times \frac{1\ event}{yr} \times \frac{100-99\%}{100}$ = 23.01 lb/yr

[3] Each of the pipelines, filters/coalescers, pumps, and pressure vessels groups occur at separate instances. Therefore, hourly emissions are based on the maximum emissions for the sum of the emissions of Group F, G, and each of the remaining units. The annual emissions (lb/yr) are the sum of the speciated emissions of all units.

Shutdown Vapor Parameters Sent to FLR-5

Unit ID	Description	Hours Per Event (hr/event)	Frequency per Year (event/yr)	ID (ft)	Height (ft)	Total Volume [1] (ft^3/event)	Total Volume Rate [2] (ft^3/hr)	Vapor Density (lb/ft^3)	Component Vapor Mass Fraction [3] C1	C2	C3	iC4	C4	iC5	C5	C6	C7	Gas Heating Rate [4] (MMBtu/hr)
Pressure Vessels																		
31-358-1 Deeth	DC2	12	1	16	126	28,551	2,379	3.35	0.03	0.78	0.13	0.03	0.02	5.26E-03	3.26E-03	4.16E-04	2.51E-03	4.42
30-358-1	DC2 Reflux Accum	12	1	10	50	4,712	393	7.72	0.02	0.97	9.82E-03	2.64E-07	6.07E-09	6.07E-09	6.07E-09	8.61E-10	5.20E-09	0.66
30-358-4	C2 Comp suct scrub	12	1	6.5	10	548	46	7.72	0.02	0.97	9.82E-03	2.64E-07	6.07E-09	6.07E-09	6.07E-09	8.61E-10	5.20E-09	0.08
30-358-6	Refrig comp suct scrub	12	1	8	10	905	75	1.50	7.13E-09	0.13	0.86	0.01	1.00E-03	1.65E-08	1.65E-08	2.35E-09	1.42E-08	0.17
30-358-7	Refrig Accumulator	12	1	8	24	1,608	134	1.50	7.13E-09	0.13	0.86	0.01	1.00E-03	1.65E-08	1.65E-08	2.35E-09	1.42E-08	0.31
31-358-4	DC3	12	1	13	114	16,857	1,405	0.83	6.82E-09	0.11	0.65	0.08	0.13	0.02	0.01	9.13E-04	5.52E-03	3.54
30-358-9	DC3 Reflux Accum	12	1	10	40	3,927	327	1.50	7.13E-09	0.13	0.86	0.01	1.00E-03	1.65E-08	1.65E-08	2.35E-09	1.42E-08	0.75
30-358-401A/B	C3 COS Reactors	6	1	6	30	1,018	170	1.50	7.13E-09	0.13	0.86	0.01	1.00E-03	1.65E-08	1.65E-08	2.35E-09	1.42E-08	0.39
30-358-402A/B	C3 H2S Reactors	6	1	7	34	1,578	263	1.50	7.13E-09	0.13	0.86	0.01	1.00E-03	1.65E-08	1.65E-08	2.35E-09	1.42E-08	0.61
31-358-5	DC4	12	1	9.5	98	7,620	635	0.33	3.36E-25	7.86E-10	6.91E-03	0.31	0.54	0.07	0.05	3.35E-03	0.02	2.04
30-358-10	DC4 Reflux accum	12	1	8.5	30	2,185	182	0.46	3.64E-25	3.64E-25	7.91E-03	0.36	0.63	1.40E-03	4.62E-05	3.52E-12	2.13E-11	0.57
31-358-6	C4 Splitter	12	1	12	212	25,334	2,111	0.46	3.64E-25	3.64E-25	7.91E-03	0.36	0.63	1.40E-03	4.62E-05	3.52E-12	2.13E-11	6.57
30-358-11	C4 Splitter comp K.O.	12	1	6.5	16	747	62	0.59	3.64E-25	3.64E-25	0.02	0.96	0.01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.19
30-358-12	C4 Splitter Reflux accum	12	1	8.5	40	2,752	229	0.46	3.64E-25	3.64E-25	0.02	0.96	0.01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.71
30-358-501A/B/C	Gasoline treaters	12	1	8	16	3,619	302	0.12	0.00E+00	2.77E-24	8.57E-11	2.64E-04	0.02	0.49	0.33	0.02	0.13	1.15
30-358-502A/B/C	Caustic separators	12	1	6	20	2,205	184	0.12	0.00E+00	2.77E-24	8.57E-11	2.64E-04	0.02	0.49	0.33	0.02	0.13	0.70
30-358-601A/B	Caustic Contactors	12	1	12	50	14,024	1,169	0.12	0.00E+00	2.77E-24	8.57E-11	2.64E-04	0.02	0.49	0.33	0.02	0.13	4.45
30-358-602A/B	Caustic Settlers	12	1	6	30	2,036	170	0.12	0.00E+00	2.77E-24	8.57E-11	2.64E-04	0.02	0.49	0.33	0.02	0.13	0.65
Pipelines																		
	RP	12	1	0.83	3,800	2,487	207	3.35	0.03	0.78	0.13	0.03	0.02	5.26E-03	3.26E-03	4.16E-04	2.51E-03	0.38
	C2	12	1	0.83	3,800	2,487	207	7.72	0.02	0.97	9.82E-03	2.64E-07	6.07E-09	6.07E-09	6.07E-09	8.61E-10	5.20E-09	0.35
	C3	12	1	0.67	3,800	1,990	166	1.50	7.13E-09	0.13	0.86	0.01	1.00E-03	1.65E-08	1.65E-08	2.35E-09	1.42E-08	0.38
	iC4	12	1	0.5	3,800	1,492	124	0.59	3.64E-25	3.64E-25	0.02	0.96	0.01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.38
	nC4	12	1	0.5	3,800	1,492	124	0.40	0.00E+00	0.00E+00	0.00E+00	0.04	0.96	2.10E-03	1.00E-04	0.00E+00	0.00E+00	0.39
	C5+	12	1	0.5	3,800	1,492	124	0.12	0.00E+00	2.77E-24	8.57E-11	2.64E-04	0.02	0.49	0.33	0.02	0.13	0.47
Filters/Coalescers																		
15-358-1A/B	Plant inlet feed filters	2	1	3	7.25	51	26	3.35	0.03	0.78	0.13	0.03	0.02	5.26E-03	3.26E-03	4.16E-04	2.51E-03	0.05
15-358-2A/B	Plant feed inlet coalescers	2	1	5	5.25	103	52	3.35	0.03	0.78	0.13	0.03	0.02	5.26E-03	3.26E-03	4.16E-04	2.51E-03	0.10
15-358-401	Treated Propane Filter Coalescer	2	1	3	5.25	37	19	1.50	7.13E-09	0.13	0.86	0.01	1.00E-03	1.65E-08	1.65E-08	2.35E-09	1.42E-08	0.04
15-358-501	Treated gasoline coalescer	2	1	2.33	5.25	22	11	0.12	0.00E+00	2.77E-24	8.57E-11	2.64E-04	0.02	0.49	0.33	0.02	0.13	0.04
15-358-601	n-butane product coalescer	2	1	3	5.25	37	19	0.40	0.00E+00	0.00E+00	0.00E+00	0.04	0.96	2.10E-03	1.00E-04	0.00E+00	0.00E+00	0.06
Compressors																		
11-358-1A/B	Ethane	1	1	-	-	2,000	2,000	7.72	0.02	0.97	9.82E-03	2.64E-07	6.07E-09	6.07E-09	6.07E-09	8.61E-10	5.20E-09	3.38
11-358-2A/B	Refrigeration	2	1	-	-	1,200	600	1.50	7.13E-09	0.13	0.86	0.01	1.00E-03	1.65E-08	1.65E-08	2.35E-09	1.42E-08	1.38
11-358-3	C4 Splitter	2	1	-	-	1,000	500	0.59	3.64E-25	3.64E-25	0.02	0.96	0.01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.54

[1] Total Volume (ft^3/event) = Pi x (ID (ft) / 2)^2 x Height (ft)

Pressure Vessel 31-358-1 Deeth Total Volume (ft^3/event) = π | (16 ft / 2)^2 | 126 ft = 28,551 ft3/event

[2] Total Volume Rate (ft^3/hr) = Total Volume (ft^3/event) / Hours Per Event (hr/event)

Pressure Vessel 31-358-1 Deeth Total Volume (ft^3/hr) = $\frac{28{,}551\ ft3}{event} \times \frac{event}{12\ hr}$ = 2,379 ft3/hr

[3] The mass fraction ratio of n-hexane to n-hexane and higher is 14.2 %

[4] Speciated Gas Heating Rate (MMBtu/hr) = Gas Volume Flow Rate (ft^3/hr) x Component Mass Fraction x Higher Heating Value (Btu/ft^3) x 1 MMBtu / 1,000,000 Btu

Targa Midstream Services LLC - Mont Belvieu Plant
Shutdown Emissions Sent to FLR-5

Shutdown Vapor Emissions Sent to FLR-5

			Controlled Weight Per Hour (lb/hr) [1]									Controlled Weight Per Year (lb/yr) [2]								
Unit ID	Description	Emission Groups	C1	C2	C3	iC4	C4	iC5	C5	C6	C7	C1	C2	C3	iC4	C4	iC5	C5	C6	C7
Pressure Vessels																				
31-358-1 Deeth	DC2	H	2.57	61.80	10.58	4.29	3.16	0.84	0.52	0.07	0.40	30.83	741.64	126.92	51.47	37.92	10.05	6.23	0.79	4.80
30-358-1	DC2 Reflux Accum	H	0.62	29.40	0.30	1.60E-05	3.68E-07	3.68E-07	3.68E-07	5.22E-08	3.16E-07	7.39	352.79	3.57	1.92E-04	4.41E-06	4.41E-06	4.41E-06	6.27E-07	3.79E-06
30-358-4	C2 Comp suct scrub	H	0.07	3.42	0.03	1.86E-06	4.27E-08	4.27E-08	4.27E-08	6.07E-09	3.67E-08	0.86	40.99	0.41	2.23E-05	5.13E-07	5.13E-07	5.13E-07	7.28E-08	4.40E-07
30-358-6	Refrig comp suct scrub	I	8.04E-09	0.15	0.97	0.02	2.26E-03	3.73E-08	3.73E-08	5.29E-09	3.20E-08	9.65E-08	1.75	11.61	0.29	0.03	4.47E-07	4.47E-07	6.35E-08	3.84E-07
30-358-7	Refrig Accumulator	I	1.43E-08	0.26	1.72	0.04	4.01E-03	6.63E-08	6.63E-08	9.41E-09	5.68E-08	1.72E-07	3.12	20.64	0.52	0.05	7.95E-07	7.95E-07	1.13E-07	6.82E-07
31-358-4	DC3	J	7.97E-08	1.26	7.55	1.87	3.02	0.43	0.29	0.02	0.13	9.57E-07	15.13	90.65	22.44	36.20	5.12	3.43	0.26	1.55
30-358-9	DC3 Reflux Accum	J	3.49E-08	0.63	4.20	0.11	9.80E-03	1.62E-07	1.62E-07	2.30E-08	1.39E-07	4.19E-07	7.61	50.40	1.28	0.12	1.94E-06	1.94E-06	2.76E-07	1.67E-06
30-358-401A/B	C3 COS Reactors	K	1.81E-08	0.33	2.18	0.06	5.08E-03	8.39E-08	8.39E-08	1.19E-08	7.19E-08	1.09E-07	1.97	13.06	0.33	0.03	5.03E-07	5.03E-07	7.14E-08	4.32E-07
30-358-402A/B	C3 H2S Reactors	K	2.80E-08	0.51	3.37	0.09	7.87E-03	1.30E-07	1.30E-07	1.85E-08	1.12E-07	1.68E-07	3.06	20.25	0.51	0.05	7.80E-07	7.80E-07	1.11E-07	6.69E-07
31-358-5	DC4	L	6.94E-25	1.62E-09	0.01	1.28	2.23	0.30	0.20	0.01	0.08	8.33E-24	1.95E-08	0.17	15.34	26.70	3.61	2.38	0.17	1.00
30-358-10	DC4 Reflux accum	L	3.02E-25	3.02E-25	6.56E-03	0.60	1.04	2.32E-03	7.66E-05	5.84E-12	3.53E-11	3.62E-24	3.62E-24	0.08	7.19	12.53	0.03	9.19E-04	7.00E-11	4.23E-10
31-358-6	C4 Splitter	L	3.50E-24	3.50E-24	0.08	6.95	12.11	0.03	8.88E-04	6.77E-11	4.09E-10	4.20E-23	4.20E-23	0.91	83.38	145.30	0.32	0.01	8.12E-10	4.91E-09
30-358-11	C4 Splitter comp K.O.	L	1.35E-25	1.35E-25	8.31E-03	0.71	9.46E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.61E-24	1.61E-24	0.10	8.55	0.11	0.00E+00	0.00E+00	0.00E+00	0.00E+00
30-358-12	C4 Splitter Reflux accum	L	3.81E-25	3.81E-25	0.02	2.02	0.03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.57E-24	4.57E-24	0.28	24.19	0.32	0.00E+00	0.00E+00	0.00E+00	0.00E+00
30-358-501A/B/C	Gasoline treaters	L	0.00E+00	9.91E-25	3.07E-11	1.89E-04	0.02	0.35	0.23	0.02	0.10	0.00E+00	1.19E-23	3.68E-10	2.27E-03	0.20	4.24	2.81	0.19	1.15
30-358-502A/B/C	Caustic separators	L	0.00E+00	6.04E-25	1.87E-11	1.15E-04	0.01	0.22	0.14	9.66E-03	0.06	0.00E+00	7.24E-24	2.24E-10	1.38E-03	0.12	2.58	1.71	0.12	0.70
30-358-601A/B	Caustic Contactors	L	0.00E+00	3.84E-24	1.19E-10	7.32E-04	0.06	1.37	0.91	0.06	0.37	0.00E+00	4.61E-23	1.43E-09	8.79E-03	0.76	16.43	10.89	0.74	4.45
30-358-602A/B	Caustic Settlers	L	0.00E+00	5.57E-25	1.73E-11	1.06E-04	9.24E-03	0.20	0.13	8.92E-03	0.05	0.00E+00	6.69E-24	2.07E-10	1.28E-03	0.11	2.39	1.58	0.11	0.65
Pipelines																				
	RP	-	0.22	5.38	0.92	0.37	0.28	0.07	0.05	5.77E-03	0.03	2.69	64.60	11.06	4.48	3.30	0.88	0.54	0.07	0.42
	C2	-	0.33	15.52	0.16	8.43E-06	1.94E-07	1.94E-07	1.94E-07	2.76E-08	1.67E-07	3.90	186.19	1.88	1.01E-04	2.33E-06	2.33E-06	2.33E-06	3.31E-07	2.00E-06
	C3	-	1.77E-08	0.32	2.13	0.05	4.96E-03	8.20E-08	8.20E-08	1.16E-08	7.03E-08	2.12E-07	3.86	25.53	0.65	0.06	9.83E-07	9.83E-07	1.40E-07	8.44E-07
	iC4	-	2.69E-25	2.69E-25	0.02	1.42	0.02	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.23E-24	3.23E-24	0.20	17.10	0.23	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	nC4	-	0.00E+00	0.00E+00	0.00E+00	0.04	0.96	2.11E-03	1.00E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.48	11.55	0.03	1.21E-03	0.00E+00	0.00E+00
	C5+	-	0.00E+00	4.08E-25	1.27E-11	7.79E-05	6.78E-03	0.15	0.10	6.54E-03	0.04	0.00E+00	4.90E-24	1.52E-10	9.35E-04	0.08	1.75	1.16	0.08	0.47
Filters/Coalescers																				
15-358-1A/B	Plant inlet feed filters	-	0.03	0.67	0.11	0.05	0.03	9.02E-03	5.59E-03	7.13E-04	4.31E-03	0.06	1.33	0.23	0.09	0.07	0.02	0.01	1.43E-03	8.62E-03
15-358-2A/B	Plant feed inlet coalescers	-	0.06	1.34	0.23	0.09	0.07	0.02	0.01	1.43E-03	8.67E-03	0.11	2.68	0.46	0.19	0.14	0.04	0.02	2.87E-03	0.02
15-358-401	Treated Propane Filter Coalescer	-	1.98E-09	0.04	0.24	6.04E-03	5.56E-04	9.17E-09	9.17E-09	1.30E-09	7.87E-09	3.96E-09	0.07	0.48	0.01	1.11E-03	1.83E-08	1.83E-08	2.60E-09	1.57E-08
15-358-501	Treated gasoline coalescer	-	0.00E+00	3.69E-26	1.14E-12	7.03E-06	6.12E-04	0.01	8.72E-03	5.90E-04	3.56E-03	0.00E+00	7.37E-26	2.28E-12	1.41E-05	1.22E-03	0.03	0.02	1.18E-03	7.13E-03
15-358-601	n-butane product coalescer	-	0.00E+00	0.00E+00	0.00E+00	6.01E-03	0.14	3.15E-04	1.50E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.01	0.29	6.30E-04	3.00E-05	0.00E+00	0.00E+00
Compressors																				
11-358-1A/B	Ethane	-	3.14	149.73	1.52	8.14E-05	1.87E-06	1.87E-06	1.87E-06	2.66E-07	1.61E-06	3.14	149.73	1.52	8.14E-05	1.87E-06	1.87E-06	1.87E-06	2.66E-07	1.61E-06
11-358-2A/B	Refrigeration	-	6.40E-08	1.16	7.70	0.20	0.02	2.97E-07	2.97E-07	4.21E-08	2.54E-07	1.28E-07	2.33	15.40	0.39	0.04	5.93E-07	5.93E-07	8.42E-08	5.09E-07
11-358-3	C4 Splitter	-	1.08E-24	1.08E-24	0.07	5.73	0.08	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.16E-24	2.16E-24	0.13	11.46	0.15	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Emissions [3]			3.26	149.73	11.75	11.56	15.51	2.47	1.62	0.11	0.66	48.98	1,578.85	395.94	250.40	276.46	47.50	30.81	2.52	15.23

[1] Controlled Weight Per Hour (lb/hr) = Total Volume Rate (ft^3/hr) x Liquid Density (lb/ft^3) x Component Vapor Mass Fraction x (100-(Flare Destruction Factor (%))/100

Pressure Vessel 31-358-1 Deeth C3 Weight Per Hour (lb/hr) =	2,379 ft3	3.35 lb	0.13	100-99%	=	10.58 lb/hr
	hr	ft^3		100		

[2] Controlled Weight Per Year (lb/yr) = Total Volume (ft^3/event) x Liquid Density (lb/ft^3) x Component Vapor Mass Fraction x Frequency/Year x (100-(Flare Destruction Factor (%))/100

Pressure Vessel 31-358-1 Deeth C3 Weight Per Year (lb/yr) =	28,551 ft3	3.35 lb	0.13	1 event	100-99%	=	126.92 lb/yr
	event	ft^3		yr	100		

[3] Each of the pipelines, filters/coalescers, compressors, and pressure vessels groups occur at separate instances. Therefore, hourly emissions are based on the maximum emissions for the sum of the emissions of Group H, I J, K, L, and each of the remaining units. The annual emissions (lb/yr) are the sum of the speciated emissions of all units.

Emissions Calculations

FIN	EPN	Source Name	VOC Emissions (lb/hr)	VOC Emissions [1] (tpy)
Shutdown	Shutdown	Shutdown Vapor Emissions to Atmosphere	10.52	0.07
Emissions			10.52	0.07

[1] VOC Emissions (tpy) = Total VOC Weight Per Year (lb/yr) x 1 / 2,000 (ton/lb)

$$\text{VOC Emissions (tpy)} = \frac{139.06 \text{ lb}}{\text{yr}} \times \frac{1 \text{ ton}}{2{,}000 \text{ lb}} = 0.07 \text{ tpy}$$

Component Molecular Weights

Component	MW (lb/lb-mol)
C1	16.04
C2	30.07
C3	44.10
iC4	58.12
C4	58.12
iC5	72.15
C5	72.15
C6	86.18
C7	100.21

Targa Midstream Services LLC - Mont Belvieu Plant
Shutdown Emissions Released to Atmosphere Calculations

Uncontrolled Shutdown Parameters

Unit ID	Description	Hours Per Event (hr/event)	Frequency per Year (event/yr)	ID (ft)	Height (ft)	Total Volume (ft^3)	Total Volume[1] (ft^3/hr)	Molar VOC Content[2,3] (lb-mol/yr)	Vapor Mass Fraction[4] C1	C2	C3	iC4	C4	iC5	C5	C6	C7
Pressure Vessels																	
31-358-1 Deeth	DC2	12	1	16	126	28,551	2,379	0.75	0.0633	0.8119	0.0947	0.0146	0.0107	0.0023	0.0014	0.0002	0.0009
30-358-1	DC2 Reflux Accum	12	1	10	50	4,712	393	0.12	0.0375	0.9559	0.0066	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
30-358-4	C2 Comp suct scrub	2	1	6.5	10	548	274	0.01	0.0375	0.9559	0.0066	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
30-358-6	Refrig comp suct scrub	2	1	8	10	905	452	0.02	0.0000	0.1798	0.8117	0.0078	0.0007	0.0000	0.0000	0.0000	0.0000
30-358-7	Refrig Accumulator	10	1	8	24	1,608	161	0.04	0.0000	0.1798	0.8117	0.0078	0.0007	0.0000	0.0000	0.0000	0.0000
31-358-4	DC3	12	1	13	114	16,857	1,405	0.44	0.0000	0.1606	0.6561	0.0616	0.0994	0.0113	0.0076	0.0005	0.0029
30-358-9	DC3 Reflux Accum	12	1	10	40	3,927	327	0.10	0.0000	0.1798	0.8117	0.0078	0.0007	0.0000	0.0000	0.0000	0.0000
30-358-401A/B	C3 COS Reactors	2	1	6	30	1,018	509	0.03	0.0000	0.1798	0.8117	0.0078	0.0007	0.0000	0.0000	0.0000	0.0000
30-358-402A/B	C3 H2S Reactors	2	1	7	34	1,578	789	0.04	0.0000	0.1798	0.8117	0.0078	0.0007	0.0000	0.0000	0.0000	0.0000
31-358-5	DC4	12	1	9.5	98	7,620	635	0.20	0.0000	0.0000	0.0094	0.3190	0.5550	0.0604	0.0398	0.0023	0.0141
30-358-10	DC4 Reflux accum	12	1	8.5	30	2,185	182	0.06	0.0000	0.0000	0.0104	0.3604	0.6281	0.0011	0.0000	0.0000	0.0000
31-358-6	C4 Splitter	12	1	12	212	25,334	2,111	0.67	0.0000	0.0000	0.0104	0.3604	0.6281	0.0011	0.0000	0.0000	0.0000
30-358-11	C4 Splitter comp K.O.	10	1	6.5	16	747	75	0.02	0.0000	0.0000	0.0294	0.9578	0.0127	0.0000	0.0000	0.0000	0.0000
30-358-12	C4 Splitter Reflux accum	12	1	8.5	40	2,752	229	0.07	0.0000	0.0000	0.0294	0.9578	0.0127	0.0000	0.0000	0.0000	0.0000
30-358-501A/B/C	Gasoline treaters	12	1	8	16	3,619	302	0.10	0.0000	0.0000	0.0000	0.0003	0.0291	0.5036	0.3338	0.0189	0.1143
30-358-502A/B/C	Caustic separators	10	1	6	20	2,205	221	0.06	0.0000	0.0000	0.0000	0.0003	0.0291	0.5036	0.3338	0.0189	0.1143
30-358-601A/B	Caustic Contactors	10	1	12	50	14,024	1,402	0.37	0.0000	0.0000	0.0000	0.0003	0.0291	0.5036	0.3338	0.0189	0.1143
30-358-602A/B	Caustic Settlers	10	1	6	30	2,036	204	0.05	0.0000	0.0000	0.0000	0.0003	0.0291	0.5036	0.3338	0.0189	0.1143
Pipelines																	
	RP	8	1	0.83	3,800	2,487	311	0.07	0.0633	0.8119	0.0947	0.0146	0.0107	0.0023	0.0014	0.0002	0.0009
	C2	8	1	0.83	3,800	2,487	311	0.07	0.0375	0.9559	0.0066	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	C3	8	1	0.67	3,800	1,990	249	0.05	0.0000	0.1798	0.8117	0.0078	0.0007	0.0000	0.0000	0.0000	0.0000
	iC4	8	1	0.5	3,800	1,492	187	0.04	0.0000	0.0000	0.0294	0.9578	0.0127	0.0000	0.0000	0.0000	0.0000
	nC4	8	1	0.5	3,800	1,492	187	0.04	0.0000	0.0000	0.0000	0.0401	0.9581	0.0017	0.0001	0.0000	0.0000
	C5+	8	1	0.5	3,800	1,492	187	0.04	0.0000	0.0000	0.0000	0.0003	0.0291	0.5036	0.3338	0.0189	0.1143
Filters/Coalescers																	
15-358-1A/B	Plant inlet feed filters	1	1	3	7.25	51	51	1.35E-03	0.0633	0.8119	0.0947	0.0146	0.0107	0.0023	0.0014	0.0002	0.0009
15-358-2A/B	Plant feed inlet coalescers	1	1	5	5.25	103	103	2.72E-03	0.0633	0.8119	0.0947	0.0146	0.0107	0.0023	0.0014	0.0002	0.0009
15-358-401	Treated Propane Filter Coalescer	1	1	3	5.25	37	37	9.78E-04	0.0000	0.1798	0.8117	0.0078	0.0007	0.0000	0.0000	0.0000	0.0000
15-358-501	Treated gasoline coalescer	1	1	2.33	5.25	22	22	5.92E-04	0.0000	0.0000	0.0000	0.0003	0.0291	0.5036	0.3338	0.0189	0.1143
15-358-601	n-butane product coalescer	1	1	3	5.25	37	37	9.78E-04	0.0000	0.0000	0.0000	0.0401	0.9581	0.0017	0.0001	0.0000	0.0000
Pumps																	
28-358-1A/B	DC2 Reflux Pumps	1	1	-	-	11.24	11	2.96E-04	0.0375	0.9559	0.0066	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
28-358-2A/B	DC3 Reflux Pumps	1	1	-	-	11.24	11	2.96E-04	0.0000	0.1798	0.8117	0.0078	0.0007	0.0000	0.0000	0.0000	0.0000
28-358-3A/B	C3 Inject pumps	1	1	-	-	11.24	11	2.96E-04	0.0000	0.1798	0.8117	0.0078	0.0007	0.0000	0.0000	0.0000	0.0000
28-358-4A/B	DC4 Reflux pumps	1	1	-	-	11.24	11	2.96E-04	0.0000	0.0000	0.0104	0.3604	0.6281	0.0011	0.0000	0.0000	0.0000
28-358-5A/B	Gasoline booster pumps	1	1	-	-	11.24	11	2.96E-04	0.0000	0.0000	0.0000	0.0003	0.0291	0.5036	0.3338	0.0189	0.1143
28-358-6A/B	Gasoline injection pumps	1	1	-	-	11.24	11	2.96E-04	0.0000	0.0000	0.0000	0.0003	0.0291	0.5036	0.3338	0.0189	0.1143
28-358-7A/B	C4 split bottoms pumps	1	1	-	-	11.24	11	2.96E-04	0.0000	0.0000	0.0294	0.9578	0.0127	0.0000	0.0000	0.0000	0.0000
28-358-8A/B	C4 split reflux pumps	1	1	-	-	11.24	11	2.96E-04	0.0000	0.0000	0.0000	0.0401	0.9581	0.0017	0.0001	0.0000	0.0000
28-358-9A/B	C4 Split comp K.O. drum pumps	1	1	-	-	11.24	11	2.96E-04	0.0000	0.0000	0.0294	0.9578	0.0127	0.0000	0.0000	0.0000	0.0000
28-358-10A/B	iC4 injection pumps	1	1	-	-	11.24	11	2.96E-04	0.0000	0.0000	0.0294	0.9578	0.0127	0.0000	0.0000	0.0000	0.0000
28-358-11A/B	nC4 injection pumps	1	1	-	-	11.24	11	2.96E-04	0.0000	0.0000	0.0000	0.0401	0.9581	0.0017	0.0001	0.0000	0.0000
Compressors																	
11-358-1A/B	Ethane	1	1	-	-	2,000	2,000	0.05	0.0375	0.9559	0.0066	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
11-358-2A/B	Refrigeration	2	1	-	-	1,200	600	0.03	0.0000	0.1798	0.8117	0.0078	0.0007	0.0000	0.0000	0.0000	0.0000
11-358-3	C4 Splitter	3	1	-	-	1,000	333	0.03	0.0000	0.0000	0.0294	0.9578	0.0127	0.0000	0.0000	0.0000	0.0000

[1] Total Volume (ft^3/hr) = Total Volume (ft^3/event) / Hours Per Event (hr/event)

Pressure Vessel 31-358-1 Deeth C3 Total Volume (ft^3/hr) = $\frac{28{,}551\ ft3}{event} \times \frac{event}{12\ hr}$ = 2,379 ft3/hr

[2] Emission calculations are based on a VOC content of 10,000 ppmv

[3] Molar VOC Content (lb-mol/yr) = (Frequency/Year) / (379.5 scf/lb-mol) x Total Volume (ft^3/event) x VOC Concentration (ppmv) / 1,000,000

Pressure Vessel 31-358-1 Deeth C3 Molar VOC Content (lb-mol/yr) = $\frac{1\ event}{yr} \times \frac{lb\text{-}mol}{379.5\ scf} \times \frac{28{,}551\ ft3}{event} \times \frac{10{,}000\ ppmv}{1{,}000{,}000}$ = 0.75 lb-mol/yr

[4] The mass fraction ratio of n-hexane to n-hexane and higher is 14.2 %

Uncontrolled Shutdown Emissions

			Uncontrolled Weight Per Hour (lb/hr) [2]									Uncontrolled Weight Per Year (lb/yr) [3]								
Unit ID [1]	**Description [1]**	**Emission Groups [1]**	**C1**	**C2**	**C3**	**iC4**	**C4**	**iC5**	**C5**	**C6**	**C7**	**C1**	**C2**	**C3**	**iC4**	**C4**	**iC5**	**C5**	**C6**	**C7**
Pressure Vessels																				
31-358-1 Deeth	DC2	M	6.3635	153.0528	0.26	0.05	0.04	0.01	6.43E-03	8.20E-04	5.76E-03	76.36	1836.63	3.14	0.64	0.47	0.12	0.08	9.84E-03	0.07
30-358-1	DC2 Reflux Accum	M	0.6233	29.7413	3.01E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	7.48	356.90	0.04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
30-358-4	C2 Comp suct scrub	M	0.4345	20.7334	2.10E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.87	41.47	4.20E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
30-358-6	Refrig comp suct scrub	N	0.0000	6.4453	0.43	5.41E-03	4.98E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	12.89	0.85	0.01	9.95E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00
30-358-7	Refrig Accumulator	N	0.0000	2.2916	0.15	1.92E-03	1.77E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	22.92	1.52	0.02	1.77E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00
31-358-4	DC3	O	0.0000	17.8791	1.07	0.13	0.21	0.03	0.02	1.51E-03	0.01	0.00E+00	214.55	12.85	1.59	2.57	0.36	0.24	0.02	0.13
30-358-9	DC3 Reflux Accum	O	0.0000	4.6624	0.31	3.92E-03	3.60E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	55.95	3.70	0.05	4.32E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00
30-358-401A/B	C3 COS Reactors	P	0.0000	7.2509	0.48	6.09E-03	5.60E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	14.50	0.96	0.01	1.12E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00
30-358-402A/B	C3 H2S Reactors	P	0.0000	11.2400	0.74	9.44E-03	8.68E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	22.48	1.49	0.02	1.74E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00
31-358-5	DC4	Q	0.0000	0.0000	6.92E-03	0.31	0.54	0.07	0.05	3.36E-03	0.02	0.00E+00	0.00E+00	0.08	3.72	6.48	0.88	0.58	0.04	0.28
30-358-10	DC4 Reflux accum	Q	0.0000	0.0000	2.20E-03	0.10	0.18	3.89E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.03	1.21	2.10	4.67E-03	0.00E+00	0.00E+00	0.00E+00
31-358-6	C4 Splitter	Q	0.0000	0.0000	0.03	1.17	2.03	4.51E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.31	13.98	24.37	0.05	0.00E+00	0.00E+00	0.00E+00
30-358-11	C4 Splitter comp K.O.	Q	0.0000	0.0000	2.55E-03	0.11	1.45E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.03	1.10	0.01	0.00E+00	0.00E+00	0.00E+00	0.00E+00
30-358-12	C4 Splitter Reflux accum	Q	0.0000	0.0000	7.85E-03	0.34	4.46E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.09	4.04	0.05	0.00E+00	0.00E+00	0.00E+00	0.00E+00
30-358-501A/B/C	Gasoline treaters	Q	0.0000	0.0000	0.00E+00	1.54E-04	0.01	0.29	0.19	0.01	0.09	0.00E+00	0.00E+00	0.00E+00	1.85E-03	0.16	3.46	2.30	0.16	1.09
30-358-502A/B/C	Caustic separators	Q	0.0000	0.0000	0.00E+00	1.13E-04	9.82E-03	0.21	0.14	9.47E-03	0.07	0.00E+00	0.00E+00	0.00E+00	1.13E-03	0.10	2.11	1.40	0.09	0.67
30-358-601A/B	Caustic Contactors	Q	0.0000	0.0000	0.00E+00	7.18E-04	0.06	1.34	0.89	0.06	0.42	0.00E+00	0.00E+00	0.00E+00	7.18E-03	0.62	13.43	8.90	0.60	4.23
30-358-602A/B	Caustic Settlers	Q	0.0000	0.0000	0.00E+00	1.04E-04	9.06E-03	0.19	0.13	8.74E-03	0.06	0.00E+00	0.00E+00	0.00E+00	1.04E-03	0.09	1.95	1.29	0.09	0.61
Pipelines			0.0000	0.0000								0.00E+00	0.00E+00							
	RP	-	0.8315	19.9989	0.03	6.94E-03	5.11E-03	1.35E-03	8.40E-04	1.07E-04	7.53E-04	6.65	159.99	0.27	0.06	0.04	0.01	6.72E-03	8.57E-04	6.02E-03
	C2	-	0.4934	23.5452	2.38E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.95	188.36	0.02	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	C3	-	0.0000	3.5434	0.23	2.98E-03	2.74E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	28.35	1.88	0.02	2.19E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	iC4	-	0.0000	0.0000	6.38E-03	0.27	3.63E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.05	2.19	0.03	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	nC4	-	0.0000	0.0000	0.00E+00	0.01	0.27	6.00E-04	2.86E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.09	2.19	4.80E-03	2.29E-04	0.00E+00	0.00E+00
	C5+	-	0.0000	0.0000	0.00E+00	9.55E-05	8.30E-03	0.18	0.12	8.01E-03	0.06	0.00E+00	0.00E+00	0.00E+00	7.64E-04	0.07	1.43	0.95	0.06	0.45
Filters/Coalescers			0.0000	0.0000								0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
15-358-1A/B	Plant inlet feed filters	-	0.1371	3.2967	5.64E-03	1.14E-03	8.43E-04	2.23E-04	1.38E-04	1.77E-05	1.24E-04	0.14	3.30	5.64E-03	1.14E-03	8.43E-04	2.23E-04	1.38E-04	1.77E-05	1.24E-04
15-358-2A/B	Plant feed inlet coalescers	-	0.2757	6.6312	0.01	2.30E-03	1.70E-03	4.49E-04	2.79E-04	3.55E-05	2.50E-04	0.28	6.63	0.01	2.30E-03	1.70E-03	4.49E-04	2.79E-04	3.55E-05	2.50E-04
15-358-401	Treated Propane Filter Coalescer	-	0.0000	0.5287	0.04	4.44E-04	4.08E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.53	0.04	4.44E-04	4.08E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00
15-358-501	Treated gasoline coalescer	-	0.0000	0.0000	0.00E+00	1.15E-05	9.99E-04	0.02	0.01	9.64E-04	6.77E-03	0.00E+00	0.00E+00	0.00E+00	1.15E-05	9.99E-04	0.02	0.01	9.64E-04	6.77E-03
15-358-601	n-butane product coalescer	-	0.0000	0.0000	0.00E+00	2.28E-03	0.05	1.19E-04	5.69E-06	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.28E-03	0.05	1.19E-04	5.69E-06	0.00E+00	0.00E+00
Pumps		-	0.0000	0.0000								0.00E+00	0.00E+00							
28-358-1A/B	DC2 Reflux Pumps	-	0.0178	0.8510	8.61E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.02	0.85	8.61E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
28-358-2A/B	DC3 Reflux Pumps	-	0.0000	0.1601	0.01	1.34E-04	1.24E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.16	0.01	1.34E-04	1.24E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00
28-358-3A/B	C3 Inject pumps	-	0.0000	0.1601	0.01	1.34E-04	1.24E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.16	0.01	1.34E-04	1.24E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00
28-358-4A/B	DC4 Reflux pumps	-	0.0000	0.0000	1.36E-04	6.20E-03	0.01	2.40E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.36E-04	6.20E-03	0.01	2.40E-05	0.00E+00	0.00E+00	0.00E+00
28-358-5A/B	Gasoline booster pumps	-	0.0000	0.0000	0.00E+00	5.75E-06	5.00E-04	0.01	7.13E-03	4.83E-04	3.39E-03	0.00E+00	0.00E+00	0.00E+00	5.75E-06	5.00E-04	0.01	7.13E-03	4.83E-04	3.39E-03
28-358-6A/B	Gasoline injection pumps	-	0.0000	0.0000	0.00E+00	5.75E-06	5.00E-04	0.01	7.13E-03	4.83E-04	3.39E-03	0.00E+00	0.00E+00	0.00E+00	5.75E-06	5.00E-04	0.01	7.13E-03	4.83E-04	3.39E-03
28-358-7A/B	C4 split bottoms pumps	-	0.0000	0.0000	3.84E-04	0.02	2.19E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.84E-04	0.02	2.19E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00
28-358-8A/B	C4 split reflux pumps	-	0.0000	0.0000	0.00E+00	6.90E-04	0.02	3.62E-05	1.72E-06	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	6.90E-04	0.02	3.62E-05	1.72E-06	0.00E+00	0.00E+00
28-358-9A/B	C4 Split comp K.O. drum pumps	-	0.0000	0.0000	3.84E-04	0.02	2.19E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.84E-04	0.02	2.19E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00
28-358-10A/B	iC4 injection pumps	-	0.0000	0.0000	3.84E-04	0.02	2.19E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.84E-04	0.02	2.19E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00
28-358-11A/B	nC4 injection pumps	-	0.0000	0.0000	0.00E+00	6.90E-04	0.02	3.62E-05	1.72E-06	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	6.90E-04	0.02	3.62E-05	1.72E-06	0.00E+00	0.00E+00
Compressors			0.0000	0.0000								0.00E+00	0.00E+00							
11-358-1A/B	Ethane	-	3.1744	151.4714	0.02	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.17	151.47	0.02	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
11-358-2A/B	Refrigeration	-	0.0000	8.5483	0.57	7.18E-03	6.60E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	17.10	1.13	0.01	1.32E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00
11-358-3	C4 Splitter	-	0.0000	0.0000	0.01	0.49	6.49E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.03	1.47	0.02	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Emissions [4]			7.42	203.53	1.38	2.02	2.85	2.12	1.40	0.09	0.67	98.91	3135.18	28.57	30.30	39.49	23.86	15.77	1.08	7.55

[1] Emission calculations are based on a VOC content of 10,000 ppmv

[2] Uncontrolled Weight Per Hour (lb/hr) = Total Volume Rate (ft^3/hr) / 379.5 (scf/lb-mol) x Vapor Mass Fraction x Component Molecular Weight (lb/lb-mol) x VOC Concentration (ppmv) / 1,000,000

Pressure Vessel 31-358-1 Deeth C3 Weight Per Hour (lb/hr) = $\frac{2{,}379\ ft3}{hr} \times \frac{lb\text{-}mol}{379.5\ scf} \times 0.09 \times \frac{44.1\ lb}{lb\text{-}mol} \times \frac{10{,}000\ ppmv}{1{,}000{,}000}$ = 0.26 lb/hr

Uncontrolled Weight Per Hour for C1 and C2 (lb/hr) = Total Volume Rate (ft^3/hr) / 379.5 (scf/lb-mol) x Vapor Mass Fraction x Component Molecular Weight (lb/lb-mol)

Pressure Vessel 31-358-1 Deeth C3 Weight Per Hour (lb/hr) = $\frac{2{,}379\ ft3}{hr} \times \frac{lb\text{-}mol}{379.5\ scf} \times 0.063 \times \frac{16.04\ lb}{lb\text{-}mol}$ = 6.3635 lb/hr

[3] Uncontrolled Weight Per Year (lb/yr) = Component Molecular Weight (lb/lb-mol) x Molar VOC Content (lb-mol/yr) x VOC Vapor Mass Fraction

Pressure Vessel 31-358-1 Deeth C3 Weight Per Year (lb/yr) = $\frac{44.1\ lb}{lb\text{-}mol} \times \frac{7.52E\text{-}01\ lbmol}{yr} \times \frac{0.09}{yr}$ = 3.14 lb/yr

Uncontrolled Weight Per Year for C1 and C2 (lb/yr) = Uncontrolled Weight Per Hour (lb/hr) x Hours Per Event (hr/event) x Frequency per Year (event/yr)

Filter/Coalescers 15-358-1A/Bs C3 Weight Per Year (lb/yr) = $\frac{6.3635\ lb}{hr} \times \frac{12\ hr}{event} \times \frac{1\ event}{yr}$ = 76.36 lb/yr

[4] Each of the pipelines, filters/coalescers, pumps, compressors, and pressure vessels groups occur at separate instances. Therefore, hourly emissions are based on the maximum emissions for the sum of the emissions of Group M, N, O. P, Q, and each of the remaining units.

Targa Midstream Services LLC - Mont Belvieu Plant
Pilot Gas & Supplemental Fuel Flare Calculations

Input Data - Pilot Gas
Gas Stream Heat Value = 1,015 Btu/scf

Number of Pilots = 4
Average Flowrate = 50 scf/hr-pilot
Maximum Flowrate = 0.833 scfm/pilot

Hourly Flowrate [1] = 200 scf/hr
Hours of Operation = 8,760 hrs/yr
Annual Flowrate [2] = 1.752 MMscf/yr
Gas Stream Heat Input [3] = 0.20 MMBtu/hr
Gas Stream Heat Input [4] = 1,778 MMBtu/yr

Input Data - Supplemental Fuel
Supplemental Fuel = 6.75 MMBtu/hr
Supplemental Fuel = 59,098 MMBtu/yr

Compound	Flare Emission Factors [5] (lb/MMBtu)	Pilot Emissions [6, 7]	
		(lb/hr)	(tpy)
NO_x	0.138	0.03	0.12
CO	0.2755	0.06	0.24

Compound	Flare Emission Factors [5] (lb/MMBtu)	Supplemental Fuel Emissions [6, 7]	
		(lb/hr)	(tpy)
NO_x	0.0641	0.43	1.89
CO	0.5496	3.71	16.24

[1] Hourly Flowrate (scf/hr) = Average Flowrate (scf/hr-pilot) x Number of Pilots

$$\text{Hourly Flowrate (scf/hr)} = \frac{50.0\text{ scf}}{\text{hr-pilot}} \times 4 = \frac{200\text{ scf}}{\text{hr}}$$

[2] Annual Flowrate (MMscf/yr) = Hourly Flowrate (scf/hr) x Annual Operation (hr/yr) x (1 MMscf /10^6 scf)

$$\text{Annual Flowrate (MMscf/yr)} = \frac{200\text{ scf}}{\text{hr}} \times \frac{8{,}760\text{ hr}}{\text{yr}} \times \frac{1\text{ MMscf}}{10^6\text{ scf}} = \frac{1.752\text{ MMscf}}{\text{yr}}$$

[3] Hourly Gas Stream Heat Input (MMBtu/hr) = Hourly Flowrate (scf/hr) x Gas Stream Heat Value (Btu/scf) x (1 MMscf /10^6 scf)

$$\text{Example Hourly Gas Stream Heat Input (MMBtu/hr)} = \frac{200\text{ scf}}{\text{hr}} \times \frac{1{,}015\text{ Btu}}{\text{scf}} \times \frac{1\text{ MMBtu}}{10^6\text{ Btu}} \quad \frac{0.20\text{ MMBtu}}{\text{hr}}$$

[4] Annual Gas Stream Heat Input (MMBtu/yr) = Hourly Gas Stream Heat Input (MMBtu/hr) x Hours of Operation (hrs/yr)

$$\text{Example Annual Gas Stream Heat Input (MMBtu/yr)} = \frac{0.20\text{ MMBtu}}{\text{hr}} \times \frac{8{,}760\text{ hrs}}{\text{yr}} = \frac{1{,}778\text{ MMBtu}}{\text{yr}}$$

[5] Pilot gas emissions from TCEQ "Air Permit Guidance For Chemical Sources, Flare And Vapor Oxidizers" (Draft Oct. 2000) Table 4, emission factors for industrial flares combusting high-Btu vapors.
Supplemental fuel emissions from TCEQ "Air Permit Guidance For Chemical Sources, Flare And Vapor Oxidizers" (Draft Oct. 2000) Table 4, emission factors for industrial flares combusting low-Btu vapors, since the supplemental fuel will be mixed with the amine and dehydrator waste gases and the mixture will be 300 Btu/scf.

[6] Maximum Potential Hourly Emission Rate (lb/hr) = Flare Emission Factor (lb/MMBtu) x Gas Stream Heat Input (MMBtu/hr)

$$\text{Example } NO_x \text{ Hourly Emission Rate (lb/hr)} = \frac{0.138\text{ lb}}{\text{MMBtu}} \times \frac{0.20\text{ MMBtu}}{\text{hr}} = \frac{0.03\text{ lb}}{\text{hr}}$$

[7] Maximum Potential Annual Emission Rate (tpy) = Flare Emission Factor (lb/MMBtu) x Gas Stream Heat Input (MMBtu/yr) x (1 ton / 2,000 lb)

$$\text{Example } NO_x \text{ Annual Emission Rate (tpy)} = \frac{0.138\text{ lb}}{\text{MMBtu}} \times \frac{1{,}778\text{ MMBtu}}{\text{yr}} \times \frac{1\text{ ton}}{2{,}000\text{ lb}} = \frac{0.12\text{ ton}}{\text{yr}}$$

Targa Midstream Services LLC - Mont Belvieu Plant
Pilot Gas & Supplemental Fuel Flare Calculations

Flare Emissions - Pilot Gas & Supplemental Fuel - VOC

Input Data

Gas Stream Heat Value =	1,015	Btu/scf
Number of Pilots =	4	
Average Flowrate =	50	scf/hr-pilot
Maximum Flowrate =	0.833	scfm/pilot
Hourly Flowrate [1] =	200	scf/hr
Hours of Operation =	8,760	hrs/yr
Annual Flowrate [2] =	1.752	MMscf/yr

Input Data - Supplemental Fuel

Supplemental Fuel =	6,646.65	scf/hr
Hours of Operation =	8,760	hrs/yr
Supplemental Fuel =	58.22	MMscf/yr

Compound	Composition [3] (wt %)	MW (lb/lb-mole)	DRE [4] (%)	Gas Vented to Flare [5] (lb/hr)	Gas Vented to Flare [5] (tpy)	Controlled Emissions [6,7] (lb/hr)	Controlled Emissions [6,7] (tpy)
Propane	0.71	44.10	99%	5.64	24.72	0.06	0.25
i-Butane	0.23	58.12	98%	2.38	10.42	0.05	0.21
n-Butane	0.21	58.12	98%	2.17	9.49	0.04	0.19
i-Pentane	0.15	72.15	98%	1.97	8.63	0.04	0.17
n-Pentane	0.08	72.15	98%	0.99	4.32	0.02	0.09
n-Hexane	0.43	86.18	98%	6.64	29.07	0.13	0.58
VOC [8]	1.80	-	0.98	19.78	86.66	0.34	1.49

[1] Hourly Flowrate (scf/hr) = Average Flowrate (scf/hr-pilot) x Number of Pilots

Hourly Flowrate (scf/hr) = $\frac{50.0 \text{ scf}}{\text{hr-pilot}} \times 4 = \frac{200 \text{ scf}}{\text{hr}}$

[2] Annual Flowrate (MMscf/yr) = Hourly Flowrate (scf/hr) x Annual Operation (hr/yr) x (1 MMscf /10^6 scf)

Annual Flowrate (MMscf/yr) = $\frac{200 \text{ scf}}{\text{hr}} \times \frac{8{,}760 \text{ hr}}{\text{yr}} \times \frac{1 \text{ MMscf}}{10^6 \text{ scf}} = \frac{1.752 \text{ MMscf}}{\text{yr}}$

[3] Composition of the gas stream is based on similar operations at the facility.

[4] Per TCEQ Air Permits Division, *Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers* , RG-109 (Draft), October 2000.

[5] Gas Vented to Flare (lb/hr) = (Pilot Gas Hourly Flowrate (scf/hr) + Supplemental Fuel Hourly Flowrate (scf/hr)) x Mole Percent / 100 x MW (lb/lb-mole) / 379.5 (scf/lb-mole)

Example Propane Hourly Emission Rate (lb/hr) = $\left(\frac{200 \text{ scf}}{\text{hr}} + \frac{6{,}646.65 \text{ scf}}{\text{hr}}\right) \times \frac{0.71 \%}{100} \times \frac{44.10 \text{ lb}}{\text{lb-mole}} \times \frac{\text{lb-mole}}{379.5 \text{ scf}} = \frac{5.64 \text{ lb}}{\text{hr}}$

[6] Annual Emissions (tpy) = Hourly Emissions (lb/yr) x Hours of Operation (hrs/yr) x (1 ton / 2,000 lb)

Example Propane Vented to Flare Annual Emission Rate (tpy) = $\frac{5.64 \text{ lb}}{\text{hr}} \times \frac{8{,}760 \text{ hrs}}{\text{yr}} \times \frac{1 \text{ ton}}{2{,}000 \text{ lb}} = \frac{24.72 \text{ ton}}{\text{yr}}$

[7] Controlled Maximum Potential Hourly Emission Rate (lb/hr) = Gas Vented to Flare (lb/hr) x (100 - DRE(%))/100

Example Controlled Propane Hourly Emission Rate (lb/hr) = $\frac{5.64 \text{ lb}}{\text{hr}} \times \frac{(100 - 99\%)}{100} = \frac{0.06 \text{ lb}}{\text{hr}}$

[8] Total VOC taken as the sum of NMNEHC.

Targa Midstream Services LLC - Mont Belvieu Plant
Supplemental Fuel to FLR-5

	Dehydrator Waste Stream	Amine Waste Stream
Net HV (Btu/ft^3)	381.36	96.49
Flow Rate (ft^3/hr)	1,830.68	24,084.04
Heat Rate (Btu/hr)	698,152.00	2.32E+06
Heat Rate (MMBtu/hr)	0.70	2.32
Heat Rate (Btu/yr)	6.12E+09	2.04E+10
Heat Rate (MMBtu/yr)	6,115.81	20,357.48

	Supplemental Fuel	Total [1]
Net HV (Btu/ft^3)	1,015.00	300.00
Flow Rate (ft^3/hr)	6,646.65	32,561.38
Heat Rate (Btu/hr)	6.75E+06	9.77E+06
Heat Rate (Btu/yr)	5.91E+10	8.56E+10

[1] Total Net HV represents minimum value based on NSPS 60.18.

8. EMISSIONS POINT SUMMARY (TCEQ TABLE 1(A))

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	March 2012	**Permit No.:**	TBD	**Regulated Entity No.:**	RN100222900
Area Name:	Mont Belvieu Fractionator			**Customer Reference No.:**	CN601301559

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) Pound	(B) TPY
FLR-5	FLR-5, AU-4, TEG-2	Flare - Normal Operation	CO	5.42	23.76
			NO_x	0.65	2.87
			VOC	0.39	1.71
			SO_2	0.09	0.19
			H_2S	<0.01	<0.01
F5A	F5A	Hot Oil Heater	CO	5.34	23.41
			NO_x	0.72	3.16
			$PM/PM_{10}/PM_{2.5}$	0.58	2.53
			SO_2	0.08	0.37
			VOC	0.09	0.38
F5B	F5B	Hot Oil Heater	CO	5.34	23.41
			NO_x	0.72	3.16
			$PM/PM_{10}/PM_{2.5}$	0.58	2.53
			SO_2	0.08	0.37
			VOC	0.09	0.38
FUG-FRAC5	FUG-FRAC5	Frac5 Fugitives	VOC	0.31	1.38
FUG-CT-9	FUG-CT-9	Cooling Tower 9	PM	0.55	2.43
			$PM_{10}/PM_{2.5}$	0.17	0.73
			VOC	1.63	7.13
FLR-5	Maintenance	Controlled Maintenance Emissions	CO	0.47	0.01
			NO_x	0.23	<0.01
			VOC	13.96	0.63
FLR-5	Startup	Controlled Startup Emissions	CO	2.45	0.05
			NO_x	1.23	0.03
			VOC	48.01	0.51
FLR-5	Shutdown	Controlled Shutdown Emissions	CO	4.69	0.05
			NO_x	2.35	0.03
			VOC	43.68	0.99
Maintenance	Maintenance	Maintenance Emissions to Atmosphere	VOC	1.15	0.01
Shutdown	Shutdown	Shutdown Emissions to Atmosphere	VOC	10.52	0.07
TK-2	TK-2	Ucarsol Storage Tank	VOC	<0.01	<0.01

EPN = Emission Point Number

FIN = Facility Identification Number

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	March 2012	**Permit No.:**	TBD
Regulated Entity No.:	RN100222900		
Area Name:	Mont Belvieu Fractionator		
Customer Reference No.:	CN601301559		

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA			EMISSION POINT DISCHARGE PARAMETERS									
1. Emission Point			4. UTM Coordinates of Emission Point			Source	6.Stack Exit Data			7. Fugitives		
EPN (A)	FIN (B)	NAME (C)	Zone	East (Meters)	North (Meters)	5. Height Above Ground (Feet)	Diameter (Feet) (A)	Velocity (FPS) (B)	Temperature (°f) (C)	Length (ft.) (A)	Width (ft.) (B)	Axis Degrees (C)
FLR-5	FLR-5, AU-4, TEG-2	Flare - Normal Operation	15	316339	3301923	185	5.5	TBD	Varies	--	--	--
F5A	F5A	Hot Oil Heater	15	316375	3302012	122	4'-4" x 3'-1"	61.85	410	--	--	--
F5B	F5B	Hot Oil Heater	15	316388	3302017	122	4'-4" x 3'-1"	61.85	410	--	--	--
FUG-FRAC5	FUG-FRAC5	Frac5 Fugitives	15	316516	3301985	10	--	--	--	464	327	345
FUG-CT-9	FUG-CT-9	Cooling Tower 9	15	316455	3302033	40	2.5 ft x 4 fans	24.1	Ambient	--	--	--
FLR-5	Maintenance	Controlled Maintenance Emissions	15	316339	3301923	185	5.5	TBD	Varies	--	--	--
FLR-5	Startup	Controlled Startup Emissions	15	316339	3301923	185	5.5	TBD	Varies	--	--	--
FLR-5	Shutdown	Controlled Shutdown Emissions	15	316339	3301923	185	5.5	TBD	Varies	--	--	--
Maintenance	Maintenance	Maintenance Emissions to Atmosphere	15	316516	3301985	10	--	--	--	464	327	345
Shutdown	Shutdown	Shutdown Emissions to Atmosphere	15	316516	3301985	10	--	--	--	464	327	345
TK-2	TK-2	Ucarsol Storage Tank	15			TBD	0.003	0.003	Ambient			

9.1. GENERAL APPLICATION (30 TAC §116.111)

This section provides a summary of the applicable State regulatory requirements outlined in 30 TAC §116.111, *General Application* (effective October 7, 2010).

9.1.1. Form PI-1 General Application (30 TAC §116.111(a)(1))

A completed TCEQ Form PI-1 signed by an authorized representative and all additional support information specified on the form is provided in this permit application.

9.1.2. Protection of Public Health and Welfare (30 TAC §116.111(a)(2)(A))

Targa will comply with all rules and regulations of the commission and with the intent of the Texas Clean Air Act (TCAA; the Act), including protection of the health and property of the public. A review of potentially applicable rules is provided in Sections 9.2 through 9.11.

As indicated on the area map in Section 4, no elementary, junior high/middle, or senior high schools are located within 3,000 feet of the Mont Belvieu Plant property line.

9.1.3. Measurement of Emissions (30 TAC 116.111(a)(2)(B))

Targa will make necessary provisions for measuring the emissions of significant air contaminants from the proposed project to demonstrate ongoing compliance with permit limitations, as required by the Executive Director. Targa will follow the guidelines of the "Texas Commission on Environmental Quality Sampling Procedures Manual", as applicable.

9.1.4. Best Available Control Technology (30 TAC 116.111(a)(2)(C))

Section 11 of this permit application demonstrates that the proposed project will utilize BACT.

9.1.5. New Source Performance Standards (30 TAC 116.111(a)(2)(D))

The following New Source Performance Standards (NSPS) subparts apply to the sources associated with the proposed project:

- Subpart A – General Provisions
- Subpart Db – Industrial-Commercial-Institutional Steam Generating Units
- Subpart OOOO – Crude Oil and Natural Gas Production, Transmission, and Distribution

A detailed discussion is located in Section 10 of this application.

9.1.6. National Emissions Standards for Hazardous Air Pollutants (30 TAC 116.111(a)(2)(E))

The Mont Belvieu Plant is not an affected source category under any of the National Emissions Standards for Hazardous Air Pollutants (NESHAP) subparts in 40 CFR Part 61. Therefore the requirements of this part do not apply.

9.1.7. NESHAP for Source Categories (30 TAC 116.111(a)(2)(F))

The following NESHAP subparts in 40 CFR Part 63 apply to the proposed project:

- Subpart A – General Provisions
- Subpart HH – National Emission Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities

Detailed discussion is located in Section 10 of this application.

9.1.8. Performance Demonstration (30 TAC 116.111(a)(2)(G))

The proposed project will achieve the performance specified in this permit application. Targa will submit additional engineering data or perform ambient monitoring or stack testing for the proposed project, if required by the TCEQ, to confirm performance as represented in the permit application.

9.1.9. Nonattainment Review (30 TAC 116.111(a)(2)(H))

The Mont Belvieu Plant is located in Chambers County, which is currently designated as a serious nonattainment area for the eight-hour ozone standard.[11] NNSR applicability is determined based on the existing emissions and increase in emissions of NO_x and VOCs as ozone precursors. The site is considered an existing major source under the NNSR permitting program. Therefore, Targa has provided an analysis in Section 10 of this permit application demonstrating the proposed project will not trigger NNSR permitting requirements.

9.1.10. Prevention of Significant Deterioration Review (30 TAC 116.111(a)(2)(I))

The Mont Belvieu Plant is located in Chambers County, which is currently classified as an attainment/unclassified area for NO_2, CO, PM/PM_{10}/$PM_{2.5}$, and SO_2.[12] Therefore, Targa has addressed PSD applicability for these pollutants in Section 10 of this permit application.

9.1.11. Air Dispersion Modeling (30 TAC 116.111(a)(2)(J))

Upon request from TCEQ, Targa will submit air dispersion modeling for the proposed project to confirm performance as represented in the permit application.

9.1.12. Hazardous Air Pollutants (30 TAC 116.111(a)(2)(K))

This regulation refers to 30 TAC Chapter 116, Subchapter E, which applies to new and reconstructed major sources of HAPs that are not subject to a maximum available control technology (MACT) standard under 40 CFR Part 63 when they are constructed or reconstructed. The Mont Belvieu Plant is not a major source of HAPs; therefore, this rule does not apply.

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[11] Per 40 CFR §81.344 (Effective October 31, 2008).

[12] Ibid.

9.1.13. Mass Cap and Trade Allowances (30 TAC 116.111(a)(2)(L))

This regulation refers to Chapter 101, Subchapter H, Division 3, which applies to facilities in the Houston-Galveston-Brazoria ozone nonattainment area. The Mont Belvieu Plant is located in the Houston-Galveston-Brazoria ozone nonattainment area. Therefore, Targa will comply with all requirements of this regulation as applicable to the proposed project. Additionally, Targa holds enough NO_X allowances to cover additional emissions associated with this project.

9.1.14. Notice Requirements (30 TAC 116.111(b))

Targa will comply with all applicable notice requirements under Chapter 39 associated with this permit application.

9.2. GENERAL AIR QUALITY RULES (30 TAC CHAPTER 101)

Targa will comply with all the applicable requirements of the TCEQ General Air Quality Rules as outlined in 30 TAC Chapter 101. The potential applicability of this chapter to the proposed project is detailed in Table 9-1 at the end of this section.

9.3. CONTROL OF AIR POLLUTION FROM VISIBLE EMISSIONS AND PARTICULATE MATTER (30 TAC CHAPTER 111)

30 TAC Chapter 111 outlines applicable requirements for the control of air pollution from visible emissions and particulate matter. The potential applicability of this chapter to the proposed project is detailed in Table 9-2 at the end of this section.

9.4. CONTROL OF AIR POLLUTION FROM SULFUR COMPOUNDS (30 TAC CHAPTER 112)

30 TAC Chapter 112 outlines applicable requirements for the control of air pollution from sulfur compounds. The potential applicability of this chapter to the proposed project is detailed in Table 9-3 at the end of this section.

9.5. STANDARDS OF PERFORMANCE FOR HAPS AND FOR DESIGNATED FACILITIES AND POLLUTANTS (30 TAC CHAPTER 113)

30 TAC Chapter 113 outlines applicable requirements for the control of air pollution from HAPs. The potential applicability of this chapter to the proposed project is detailed in Table 9-4 at the end of this section.

9.6. CONTROL OF AIR POLLUTION FROM MOTOR VEHICLES (30 TAC CHAPTER 114)

The provisions in 30 TAC Chapter 114 regulate emissions from motor vehicles and are not intended for industrial emissions to the atmosphere. Additionally, the proposed project will not operate any non-road large spark-ignition engines. This permit application does not involve the activities covered by these rules; therefore, the provisions of these rules do not apply to the proposed project.

9.7. CONTROL OF AIR POLLUTION FROM VOLATILE ORGANIC COMPOUNDS (VOCS) (30 TAC CHAPTER 115)

30 TAC Chapter 115 regulates VOC emissions according to source type and site location (i.e., county). The Mont Belvieu Plant is located in Chambers County, which is classified as a nonattainment county for ozone. The potential applicability of this chapter to the proposed project is detailed in Table 9-5 at the end of this section.

9.8. CONTROL OF AIR POLLUTION BY PERMITS FOR NEW CONSTRUCTION OR MODIFICATION (30 TAC CHAPTER 116)

This permit application for the proposed project at the Mont Belvieu Plant has been submitted to the TCEQ to demonstrate compliance with the applicable provisions of 30 TAC Chapter 116. A Form PI-1 is included in Section 2 of this application and is signed by an authorized Targa representative. All supporting documentation is provided within this application or in the air dispersion modeling report to be submitted under separate cover.

9.9. CONTROL OF AIR POLLUTION FROM NITROGEN COMPOUNDS (30 TAC CHAPTER 117)

30 TAC Chapter 117 regulates NO_X emissions according to source type and site location (i.e., county). The Mont Belvieu Plant is located in Chambers County, which is classified as a nonattainment county for ozone.. The potential applicability of this chapter to the proposed project is detailed in Table 9-6 at the end of this section.

9.10. CONTROL OF AIR POLLUTION EPISODES (30 TAC CHAPTER 118)

The Mont Belvieu Plant will comply with the rules relating to generalized and localized air pollution episodes, if such an episode is declared by the TCEQ.

Emission reduction plan requirements apply to major stationary sources in El Paso, Galveston, Harris, Jefferson, and Orange Counties. The Mont Belvieu Plant is located in Chambers County, which is not a designated county under §118.5; therefore, no emissions reduction plan is required.

9.11. FEDERAL OPERATING PERMITS (30 TAC CHAPTER 122)

According to the applicability requirements in 30 TAC Chapter 122.120(a)(1), any site that meets the major source definition in §122.10 is subject the requirements of Chapter 122 related to operating permits. 30 TAC Chapter 122.10(13) defines a major source as having the potential to emit (PTE) greater than any of the following limits:

- 25 tpy of combined HAPs
- 10 tpy of any single HAP
- 100 tpy of any air pollutant
- 25 tpy of NO_x or VOC in an ozone nonattainment area classified as severe

The Mont Belvieu Plant is a major source with respect to the Title V program, and the plant currently operates under Title V Operating Permit No. O-612. Targa will submit the appropriate revision to incorporate the proposed project and applicable requirements into the existing Title V permit.

Table 9-1. 30 TAC Chapter 101 Applicability

Section Number	Reference	Rule Description	Rule Applicability	Compliance Explanation
§101.2	Multiple Air Contaminant Sources or Properties	This regulation requires emission reductions from sources and properties that have an additive effect from two or more sources on a single property or from two or more properties when the level of air contaminants exceeds the ambient air quality standards.	No	Targa is not petitioning to designate two or more properties as a single property.
§101.3	Circumvention	This regulation prohibits circumvention of state or federal regulations.	Yes	Targa will not use a plan, activity, device or contrivance to conceal or appear to minimize an emission in violation of the Act or a regulation. The representations made in this permit application ensure no circumvention.
§101.4	Nuisance	This regulation prohibits emission sources from releasing air contaminants in such concentrations and duration as to be injurious to or to adversely affect human health or welfare, animal life, vegetation, or property, or as to interfere with the normal use and enjoyment of animal life, vegetation, or property.	Yes	The representations made in this permit application, the forthcoming ambient air quality modeling and health effects evaluations, and the permit issued based on these representations will ensure compliance with this requirement.
§101.5	Traffic Hazard	This regulation prohibits emissions of air contaminants, uncombined water, or other materials from any source to cause or have a tendency to cause a traffic hazard or interfere with normal road use.	Yes	The representations made in this permit application, the forthcoming ambient air quality modeling and health effects evaluations, and the permit issued based on these representations will ensure compliance with this requirement.
§101.8, §101.9, & §101.14	Sampling; Sampling Ports; and Sampling Procedures and Terminology	These regulations require sampling, access to sampling ports, and that sampling procedures be conducted according the rules specified in this regulation if requested by the TCEQ.	Yes	Targa will conduct requested sampling at the frequency, within the timeframe, and using the methods established by the TCEQ. Targa will provide a sampling port, a power source, and safe access near the point of sampling upon request from TCEQ.
§101.10	Emissions Inventory Requirements	This regulation requires the submittal of annual emissions inventories for facilities meeting certain potential and/or actual emissions levels. This regulation also allows TCEQ to request a special inventory for any source or facility, as deemed necessary by the Commission.	Yes	Targa will submit an annual emissions inventory and all related data as required by this regulation. Targa will submit any special inventory as requested by the TCEQ.
§101.20	Compliance with Environmental Protection Agency Standards	This regulation requires compliance with all applicable NSPS, NESHAP, and PSD requirements as applicable to the facility.	Yes	Targa will comply with any applicable NSPS and NESHAP regulations as demonstrated in Section 10 of this permit application. Targa will comply with any permit issued by the U.S. EPA pursuant to PSD regulations as discussed in Section 10 of this permit application.

Table 9-1. 30 TAC Chapter 101 Applicability

Section Number	Reference	Rule Description	Rule Applicability	Compliance Explanation
§101.21	The National Primary and Secondary Ambient Air Quality Standards	This regulation requires compliance with the National Primary and Secondary Ambient Air Quality Standards as specified in the Federal Clean Air Act.	Yes	Demonstration of compliance with the National Ambient Air Quality Standards (NAAQS) will be provided to TCEQ in the forthcoming air quality modeling analysis.
§101.23	Alternate Emission Reduction ("Bubble") Policy	This regulation allows the owner or operator of a facility to request approval of control of emissions from an alternate facility in lieu of compliance with an applicable regulation (also known as the "bubble" policy).	No	Targa is not requesting a "bubble" under this regulation.
§101.24 & §101.27	Inspection Fees and Emissions Fees	30 TAC §101.24 requires owners and operators to submit inspection fees, as determined by the facility's Standard Industrial Classification category. 30 TAC §101.27 requires owners and operators with a federal operating permit to submit emissions fees based on allowable levels or actual emissions at the facility.	Yes	If the Mont Belvieu Plant is subject to both inspection and emissions fees, Targa will submit only the greater of the two amounts by the specified due date.
§101.26	Surcharge on Fuel Oil in Specified Boilers	This regulation is applicable to owners and operators of an industrial or utility boiler.	No	Targa is not proposing to operate an industrial or utility boiler as part of the proposed project.
§101.28	Stringency Determination for Federal Operating Permits	This regulation allows a federal operating permit holder to comply with more stringent or equivalent requirements.	No	Targa is not requesting a determination under this regulation.
§101.150 - §101.155	Voluntary Supplemental Leak Detection Program	This regulation provides a program that encourages and provides incentives for voluntary monitoring of components.	No	Targa is not seeking participation under this voluntary program since they will be required by TCEQ and/or EPA regulations to monitor equipment components.
§101.201 - §101.233	Emissions Events and Scheduled MSS Activities	These regulations provide requirements for the reporting and recordkeeping of emissions events and scheduled maintenance, startup, and shutdown activities.	Yes	Targa will operate all emission sources and control technologies associated with the proposed project in a manner in order to reduce the likelihood of an emissions event. If an emissions event were to occur, Targa will comply with all applicable reporting, recordkeeping, and corrective action requirements. Although Targa is including various MSS activities in this application, not all activities may be included. Per Senate Bill (SB) 1134, oil and gas facilities must authorize all MSS activities before January 5, 2014.* Targa will ensure all MSS activities are authorized by this date.

Table 9-1. 30 TAC Chapter 101 Applicability

Section Number	Reference	Rule Description	Rule Applicability	Compliance Explanation
§101.300 - §101.311	Emission Credit Banking and Trading	These regulations outline the guidelines for participating in emission credit banking and trading.	No	Targa is not currently proposing to participate in the voluntary emissions credit banking and trading system.
§101.350 - §101.363	Mass Emissions Cap and Trade Program	These regulations apply only to sites in the Houston-Galveston-Brazoria ozone nonattainment area.	Yes	Targa will comply with all applicable requirements of the Mass Emissions Cap and Trade Program. Additionally, Targa holds enough NO_X allowances to cover additional emissions associated with this project.
§101.370 - §101.379	Discrete Emission Credit Banking and Trading	These regulations outline the guidelines for participating in emissions credit banking and trading.	No	Targa is not currently proposing to participate in the voluntary emissions credit banking and trading system.
§101.380 - §101.385	System Cap Trading	These regulations outline the guidelines for participating in emissions credit banking and trading.	No	Targa is not currently proposing to participate in the voluntary emissions credit banking and trading system.
§101.390 - §101.403	Highly-Reactive Volatile Organic Compound Emissions Cap and Trade Program	These regulations apply to sites located in the Houston-Galveston-Brazoria ozone nonattainment area.	No	The proposed project does not contain any services containing HRVOCs.
§101.501 - §101.508	Clean Air Interstate Rule	These regulations apply to any stationary, fossil fuel-fired boiler or stationary, fossil fuel-fired combustion turbine meeting the Clean Air Interstate Rule (CAIR) applicability requirements under 40 CFR Part 96, Subpart AA or Subpart AAA, relating to NO_x Budget Trading Program and CAIR NO_x and SO_2 Trading Programs for State Implementation Plans.	No	Targa is not currently proposing to install any fossil fuel-fired boiler or turbine as part of the proposed project.

* On June 17, 2011, SB 1134 was signed into action by the Governor.

Table 9-2. 30 TAC Chapter 111 Applicability

Section Number	Reference	Rule Applicability	Compliance Explanation
§111.111- §111.113	Visible Emissions	Yes	All stationary vents have flowrates less than 100,000 actual cubic feet per minute and will meet the opacity limit of 20% averaged over a six-minute period, as required by §111.111(a)(1)(B). Targa will demonstrate compliance with the opacity limit according to the requirements of §111.111(a)(1)(F)(i)-(iv). As required by §111.111(a)(4), there will be no visible emissions from the flare, except as allowed by §111.111(a)(4)(A). Targa will demonstrate compliance with the visible emission limitation according to the requirements of §111.111(a)(4)(A)(i)-(ii). Alternate opacity limitations are allowed under §111.113. Targa is not requesting an alternate opacity limitation at this time.
§111.121- §111.129	Incineration	No	This NSR permit application does not contain any incineration units.
§111.131- §111.139	Abrasive Blasting of Water Storage Tanks Performed by Portable Operations	No	This NSR permit application does not contain any abrasive blasting of water storage tanks.
§111.141- §111.149	Materials Handling, Construction, Roads, Streets, Alleys, and Parking Lots	No	The Mont Belvieu Plant is not located within any of the geographic areas identified in 30 TAC §111.141.
§111.151	Allowable Emissions Limits	Yes	The only proposed sources of particulate matter are the heaters and cooling tower, which will not result in emissions in excess of the applicable emission limits specified in 30 TAC §111.151.
§111.153	Emissions Limits for Steam Generators	No	This NSR permit application does not contain any oil or gas fuel-fired steam generators with heat input greater than 2,500 MMBtu/hr or any solid fossil fuel-fired steam generators.
§111.171 - §111.175	Emissions Limits on Agricultural Processes	No	This NSR permit application does not contain any agricultural processes.
§111.181 - §111.183	Exemptions for Portable or Transient Operations	No	Targa is not proposing to utilize any portable or transient operations engaged in public work projects as part of the proposed project.
§111.201 - §111.221	Outdoor Burning	No	No outdoor burning will be conducted as part of the proposed project.

Table 9-3. 30 TAC Chapter 112 Applicability

Section Number	Reference	Rule Applicability	Compliance Explanation
§112.1-§112.21	Control of Sulfur Dioxide	Yes; §112.3	The net ground level concentrations for SO_2 are set forth for the State of Texas in §112.3(a). Targa will provide air dispersion modeling to demonstrate compliance with the net ground level concentration limit of 0.4 ppmv averaged over any 30-minute period. The proposed emission sources are not subject to any other citation within Chapter 112, Subchapter A since there will be no sulfuric acid plants, sulfur recovery plants, solid fossil fuel-fired steam generators, combustion of liquid fuel, or nonferrous smelter processes associated with the proposed project.
§112.31-§112.34	Control of Hydrogen Sulfide	Yes	The net ground level concentrations for H_2S are set forth for residential, business, commercial, and industrial property in the State of Texas. Demonstration of compliance will be performed per calculation methods set forth in §112.33.
§112.41-§112.47	Control of Sulfuric Acid	No	The proposed project will not emit sulfuric acid emissions.
§112.51-§112.59	Control of Total Reduced Sulfur	No	The proposed project will not be a kraft pulp mill.

Table 9-4. 30 TAC Chapter 113 Applicability

Subchapter	Reference	Rule Applicability	Compliance Explanation
Subchapter B	National Emission Standard for Hazardous Air Pollutants	No	There are no 40 CFR Part 61 NESHAP requirements applicable to the proposed project, as discussed in Section 10 of this permit application.
Subchapter C	National Emission Standard for Hazardous Air Pollutants for Source Categories	Yes	The TCEQ has incorporated the following MACT subparts in 40 CFR Part 63 that are applicable to the emission sources associated with the proposed project: > Subpart A – General Provisions > Subpart HH – National Emission Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities Each applicable MACT Subpart of 40 CFR Part 63 is discussed in Section 10 of this application.
Subchapter D	Designated Facilities and Pollutants	No	This NSR permit application does not contain a municipal solid waste landfill, a hospital/medical/infectious waste incinerator, municipal waste combustion, or solid waste incineration.
Subchapter E	Consolidated Federal Air Rules: Synthetic Organic Chemical Manufacturing Industry (SOCMI)	No	This NSR permit application does not contain any activities subject to SOCMI regulations under 40 CFR Part 65.

Table 9-5. 30 TAC Chapter 115 Applicability

Subchapter	Division	Reference	Rule Applicability	Compliance Explanation
Subchapter B	Division 1	Storage of Volatile Organic Compounds	Yes; recordkeeping only	The proposed Ucarsol storage tank (EPN TK-2) will have a vapor pressure of less than 1.5 pounds per square inch (psia) and therefore is exempt from this division per §115.111(a)(1). Targa will keep records as required by §115.118(a)(1) in order to maintain this exemption.
	Division 2	Vent Gas Control	Yes; monitoring and recordkeeping only	The amine unit (FIN AU-4) and TEG dehydrator (FIN TEG-2) will both have uncontrolled VOC emissions less than 100 lb in any consecutive 24-hr period, meeting the exemption per §115.127(a)(2)(A). Targa will comply with all applicable monitoring and recordkeeping requirements in order to maintain this exemption.
	Division 3	Water Separation	No	The proposed project does not include any sources addressed in this division.
	Division 4	Industrial Wastewater	No	The proposed project does not include any sources addressed in this division.
	Division 5	Municipal Solid Waste Landfills	No	The proposed project does not include any sources addressed in this division.
	Division 6	Batch Processes	No	The proposed project does not include any sources addressed in this division.

Table 9-5. 30 TAC Chapter 115 Applicability

Subchapter	Division	Reference	Rule Applicability	Compliance Explanation
Subchapter C	Division 1	Loading and Unloading of Volatile Organic Compounds	No	The proposed project does not include any sources addressed in this division.
	Division 2	Filling of Gasoline Storage Vessels (Stage 1) for Motor Vehicle Fuel Dispensing Facilities		
	Division 3	Control of Volatile Organic Compound Leaks from Transport Vessels		
	Division 4	Control of Vehicle Refueling emissions (Stage II) at Motor Vehicle Fuel Dispensing Facilities		
	Division 5	Control of Reid Vapor Pressure of Gasoline		
Subchapter D	Division 1	Process Unit Turnaround and Vacuum-Producing Systems in Petroleum Refineries	No	The proposed project is not a petroleum refinery.
	Division 2	Fugitive Emission Control in Petroleum Refineries in Greg, Nueces, and Victoria Counties	No	The Mont Belvieu Plant is not located in Greg, Nueces, or Victoria County.
	Division 3	Fugitive Emission Control in Petroleum Refining, Natural Gas/Gasoline Processing, and Petrochemical Processes in Ozone Nonattainment Areas	Yes	The proposed project meets the definition of a natural gas processing plant per §115.10(30). Targa will comply with all requirements as applicable to the proposed project.
Subchapter E	Division 1	Degreasing Operations	No	The proposed project does not include any sources addressed in this division.
	Division 2	Surface Coating Processes		
	Division 3	Flexographic and Rotogravure Printing		
	Division 4	Offset Lithographic Printing		
	Division 5	Control Requirements for Surface Coating Processes		
	Division 6	Industrial Cleaning Solvents		
	Division 7	Miscellaneous Industrial Adhesives		
Subchapter F	Division 1	Cutback Asphalt	No	The proposed project does not include any sources addressed in this division.
	Division 2	Pharmaceutical Manufacturing Facilities		
	Division 3	Degassing of Storage Tanks, Transport Vessels, and Marine Vessels		
	Division 4	Petroleum Dry Cleaning Systems		

Table 9-5. 30 TAC Chapter 115 Applicability

Subchapter	Division	Reference	Rule Applicability	Compliance Explanation
Subchapter G	Division 1	Automotive Windshield Washer Fluid	No	The proposed project does not include any sources addressed in this division.
Subchapter H	Division 1 Division 2 Division 3	Vent Gas Control Cooling Tower Heat Exchange Systems Fugitive Emissions	No	The proposed project will not include any services containing HRVOCs.
Subchapter J	Division 1 Division 2 Division 3 Division 4	Alternate Means of Control Early Reductions Compliance and Control Plan Requirements Emissions Trading	Yes	The Mont Belvieu Plant will comply with all applicable requirements.

Table 9-6. 30 TAC Chapter 117 Applicability

Subchapter	Division	Reference	Rule Applicability	Compliance Explanation
Subchapter B	Division 1 Division 2 Division 3 Division 4	Beaumont-Port Arthur Ozone Nonattainment Area Major Sources Dallas-Fort Worth Ozone Nonattainment Area Major Sources Houston-Galveston-Brazoria Ozone Nonattainment Area Major Sources Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Major Sources	Yes; Division 3 only	Divisions 1, 2, and 4 do not apply because the Mont Belvieu Plant is not located in the Beaumont-Port Arthur or Dallas-Fort Worth areas. Division 3 applies because the Mont Belvieu Plant is a major source of NO_x in the Houston-Galveston-Brazoria area. Therefore, the heaters (EPNs F5A and F5B) will comply with all requirements as applicable to process heaters in Chapter 117.
Subchapter C	Division 1 Division 2 Division 3 Division 4	Beaumont-Port Arthur Ozone Nonattainment Area Utility Electric Generation Sources Dallas-Fort Worth Ozone Nonattainment Area Utility Electric Generation Sources Houston-Galveston-Brazoria Ozone Nonattainment Area Utility Electric Generation Sources Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Utility Electric Generation Sources	No	The proposed project does not include a utility electric generation source.
Subchapter D	Division 1 Division 2	Houston-Galveston-Brazoria Ozone Nonattainment Are Minor Sources Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Minor Sources	No	The Mont Belvieu Plant is not a minor source of NO_x.
Subchapter E	Division 1 Division 2 Division 3 Division 4	Utility Electric Generation in East and Central Texas Cement Kilns Water Heaters, Small Boilers, and Process Heaters East Texas Combustion	No	Divisions 1 and 4 do not apply to Chambers County. Division 2 applies only to cement kilns. Division 3 applies only to manufacturers, distributors, retailers, and installers of such units.
Subchapter F	Division 1 Division 2 Division 3	Adipic Acid Manufacturing Nitric Acid Manufacturing – Ozone Nonattainment Areas Nitric Acid Manufacturing - General	No	The proposed project will not be a nitric or adipic acid manufacturer.

Table 9-6. 30 TAC Chapter 117 Applicability

Subchapter	Division	Reference	Rule Applicability	Compliance Explanation
Subchapter G	Division 1	Compliance Stack Testing and Reporting Requirements	Yes	Targa will comply with all monitoring and testing requirements as applicable to the heaters.
	Division 2	Emissions Monitoring		
Subchapter H	Division 1	Compliance Schedules	Yes	Targa will comply with all administrative provisions as applicable to the heaters.
	Division 2	Compliance Flexibility		

10. FEDERAL REGULATORY REQUIREMENTS

This section addresses the applicability of the following federal regulatory programs for the equipment associated with the proposed project:

- NSPS in 40 CFR Part 60
- NESHAP in 40 CFR Part 61
- NESHAP in 40 CFR Part 63, i.e., MACT standards
- Nonattainment New Source Review
- Prevention of Significant Deterioration

10.1. NEW SOURCE PERFORMANCE STANDARDS

The following NSPS subparts in 40 CFR Part 60 are potentially applicable to the proposed emission sources:

Table 10.1-1. Potentially Applicable NSPS Subparts

Subpart	Description	Applicability	Affected Sources (EPN)
Subpart A	General Provisions	Yes	All sources listed below
Subpart Db	Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units	Yes	Hot Oil Heaters (EPNs F5A & F5B)
Subpart Kb	Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984	No	N/A
Subpart KKK	Standards of Performance for Equipment Leaks of VOC From Onshore Natural Gas Processing Plants	No	N/A, See NSPS OOOO
Subpart LLL	Standards of Performance for Onshore Natural Gas Processing: SO2 Emissions	No	N/A, See NSPS OOOO
Subpart OOOO	Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution (proposed)	Yes	Fugitives (EPN FUG-FRAC5)

Each potentially applicable NSPS subpart of 40 CFR Part 60 is discussed in the subsections below.

10.1.1. Subpart A – General Provisions

Any source subject to a source-specific NSPS is also subject to the general provisions of NSPS Subpart A. Unless specifically excluded by the source-specific NSPS, Subpart A generally requires initial construction notification, initial startup notification, performance tests, performance test date initial notification, general monitoring requirements, general recordkeeping requirements, and semiannual monitoring and/or excess emission reports.

10.1.2. Subpart Db – Industrial-Commercial-Institutional Steam Generating Units

NSPS Subpart Db applies to steam generating units for which construction, modification, or reconstruction is commenced after June 19, 1984, and that have a maximum design heat input capacity of greater 100 MMBtu/hr. According to §60.41b, steam generating unit and process heater are defined as:

Steam generating unit means a device that combusts any fuel and produces steam or heats water or heats any heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

According to these definitions, the table below lists the proposed emission sources considered to be steam generating units and are potentially subject to NSPS Subpart Db.

Table 10.1-2. Heaters Potentially Subject to NSPS Subpart Db

EPN	Heater Description	Size (MMBtu/hr)
F5A	Hot Oil Heater	144.45
F5B	Hot Oil Heater	144.45

Targa will comply with all emission limitation, monitoring, and recordkeeping requirements as applicable to the hot oil heaters.

10.1.3. Subpart Kb – Volatile Organic Liquid Storage Vessels

NSPS Subpart Kb applies to volatile organic liquid storage vessels constructed, reconstructed, or modified after July 23, 1984 with a capacity of 19,813 gallons (gal) or more. No tank storing a liquid with a vapor pressure less than 3.5 kilopascals (kPa) is subject to the requirements of Subpart Kb. Targa is proposing to construct an Ucarsol storage tank at the Mont Belvieu Plant; however, since the storage tank will store a liquid with a maximum true vapor pressure of 4.8 mm Hg (0.64 kPa), this subpart does not apply to this facility.

Table 10.1-3. Storage Tanks Potentially Applicable to NSPS Subpart Kb

EPN	Tank Description	TVP (kPa)
TK-2	Ucarsol Storage Tank	0.64

10.1.4. Subpart KKK – Equipment Leaks of VOC From Onshore Natural Gas Processing Plants

NSPS Subpart KKK applies to onshore natural gas processing plants constructed, reconstructed, or modified after January 20, 1984. However, onshore natural gas processing plants constructed, reconstructed, or modified after August 23, 2011 will be subject to the new proposed NSPS Subpart OOOO, as discussed in Section 10.1.6.

10.1.5. Subpart LLL – Onshore Natural Gas Processing: SO_2

NSPS Subpart LLL applies to onshore natural gas processing facilities that contain sweetening units that commence construction or modification after January 20, 1984. However, onshore natural gas processing plants constructed, reconstructed, or modified after August 23, 2011 will be subject to the new proposed NSPS Subpart OOOO, as discussed in Section 10.1.6.

10.1.6. Subpart OOOO – Crude Oil and Natural Gas Production, Transmission, and Distribution

On July 28, 2011, the EPA Administrator signed a suite of proposed new air regulations affecting both the Production/Processing and Transmission/Storage sectors of the oil and natural gas industry. One of these rules was NSPS Subpart OOOO, expected to regulate emissions of VOC and SO_2 from sources that are newly constructed, modified, or reconstructed after August 23, 2011.

The new NSPS Subpart OOOO may include new or updated emissions and work practice standards for the following proposed source types located at the Mont Belvieu Plant:

- equipment leaks at onshore natural gas processing plants
- sweetening units at onshore natural gas processing plants

Currently, NSPS Subparts KKK and LLL potentially apply to onshore natural gas processing plants constructed, reconstructed, or modified after January 20, 1984. However, any construction, reconstruction, or modification that occurs after August 23, 2011 will be subject to the new requirements of NSPS Subpart OOOO.

It is expected that the NSPS Subpart LLL exemption from control requirements per §60.640(b) will be available in the final NSPS Subpart OOOO for onshore natural gas processing facilities that contain sweetening units. The design capacity of the proposed amine unit at Train 5 will be less than two long tons per day of H_2S in acid gas (expressed as sulfur). Targa will maintain documentation demonstrating that the facility's design capacity is less than two long tons per day of H_2S expressed as sulfur per §60.647(c).

As currently proposed, affected facilities subject to NSPS Subpart OOOO must be in compliance with the rule's requirements no later than the date the final rule is published in the Federal Register or the date the facility commences operation, whichever is later. The proposed new rules are expected to be finalized no later than April 3, 2012. At the time of final rule promulgation, Targa will reassess NSPS Subpart OOOO applicability and requirements to the proposed sources at the Mont Belvieu Plant.

10.2. NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

The Mont Belvieu Plant is not a major source of HAPs and will not become a major source of HAPs as a result of the proposed project; therefore, the Mont Belvieu Plant is not subject to any of the NESHAP subparts in 40 CFR Part 61.

The following MACT subparts in 40 CFR Part 63 are potentially applicable to the proposed emissions sources:

Table 10.2-1. Potentially Applicable MACT Subparts

Subpart	Description	Applicability	Affected Sources (EPN)
Subpart A	General Provisions	Yes	All sources listed below
Subpart Q	National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers	No	N/A
Subpart HH	National Emission Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities	Yes	TEG Dehydrator (FIN TEG-2/ EPN FLR-5)
Subpart HHH	National Emission Standards for Hazardous Air Pollutants From Natural Gas Transmission and Storage Facilities	No	N/A
Subpart DDDDDD	National Emission Standards for Hazardous Air Pollutants For Industrial, Commercial, and Institutional Boilers and Process Heaters	No	N/A
Subpart JJJJJJ	National Emission Standards for Hazardous Air Pollutants For Industrial, Commercial, and Institutional Boilers Area Sources	No	N/A

Each applicable MACT Subpart of 40 CFR Part 63 is discussed in the subsections below.

10.2.1. Subpart A – General Provisions

Any source subject to a source-specific NESHAP is also subject to the general provisions of NESHAP Subpart A. Unless specifically excluded by the source-specific NESHAP, Subpart A generally requires initial construction notification, initial startup notification, performance tests, performance test date initial notification, general monitoring requirements, general recordkeeping requirements, and semiannual monitoring and/or excess emission reports.

10.2.2. Subpart Q – Industrial Process Cooling Towers

MACT Subpart Q applies to all new and existing industrial process cooling towers that are operated with chromium-based water treatment chemicals and are either major sources of HAPs or are integral parts of facilities that are major sources of HAPs as defined in §63.401. The proposed cooling tower will not be an affected source under MACT Subpart Q since it is not a major source of HAPs nor is the Mont Belvieu Plant a major source of HAPs.

10.2.3. Subpart HH – Oil and Natural Gas Production Facilities

MACT Subpart HH applies to emission sources at oil and natural gas production facilities that are HAP major or HAP area sources and that process, upgrade, or store either hydrocarbon liquids or natural gas prior to the point of custody transfer. As an area source and facility that processes natural gas, the proposed Train 5 project at the Mont Belvieu Plant will be potentially subject to the requirements of Subpart HH. According to §63.760(b)(2), the affected sources at HAP area sources include all TEG dehydrator units, as listed below:

Table 10.2-2. TEG Dehydrators Potentially Subject to MACT Subpart HH

FIN	Unit Description
TEG-2	TEG Dehydrator *

* The TEG Dehydrator will be controlled by the Flare (EPN FLR-5).

According to §63.764(e)(1)(ii), the owner/operator is exempt from the general standards if the benzene emissions from the dehydrator are less than 1.0 tpy. As shown in Section 7 of this permit application, there will be no benzene emissions from the TEG dehydrator. Therefore, the unit will only be subject to limited requirements of Subpart HH per §63.774(d)(1)(ii).

10.2.4. Subpart HHH - Hazardous Air Pollutants From Natural Gas Transmission and Storage Facilities

MACT Subpart HHH applies to natural gas transmission and storage facilities that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final end user and are major sources of HAP emissions. Per 40 CFR §63.1270(a), the Mont Belvieu Plant is not an affected source since it is not a major source of HAP emissions and it is not considered a natural gas transmission or storage facility.

10.2.5. Subpart DDDDD - Industrial, Commercial, and Institutional Boilers and Process Heaters

MACT Subpart DDDDD establishes emission limits, operational standards, and compliance demonstration requirements for HAP emissions from industrial, commercial, and institutional boilers and process heaters operating within major sources of HAP emissions. Per 40 CFR §63.7485, the proposed hot oil heaters will not be subject to this subpart since they will not operate within a major source of HAP emissions.

10.2.6. Subpart JJJJJJ - Industrial, Commercial, and Institutional Boilers Area Sources

MACT Subpart JJJJJJ establishes emission limits, operational standards, and energy assessment requirements for HAP emissions from industrial, commercial, and institutional boilers operating within area sources of HAP emissions. According to §63.11194(a)(1), an affected source is the collection of all existing industrial, commercial, and institutional boilers within a subcategory (coal, biomass, oil). The proposed hot oil heaters will not be subject to Subpart JJJJJJ since they do not fit into one of the subcategories covered by the rule.

10.3. FEDERAL NEW SOURCE REVIEW REQUIREMENTS

Under U.S. EPA and TCEQ rules, sites located in areas that are designated in attainment of the NAAQS for a criteria pollutant are potentially regulated under the PSD program if they are considered major sources. Major source thresholds are defined in 40 CFR §52.21 (b)(1)(i). The Mont Belvieu Plant is considered an existing major source under PSD.

The Mont Belvieu Plant is located in Chambers County, which has been designated as a severe nonattainment area for the eight-hour ozone standard.[13] VOC and NO_x are considered to be precursors to ground-level ozone formation; therefore, NNSR review is required if a modification of an existing major source results in a significant net emission rate increase of a regulated pollutant. The Mont Belvieu Plant is classified as an existing major source under NNSR for NO_x and VOC.

The following sections describe the PSD and NNSR applicability analysis for the proposed project.

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[13] Per 40 CFR §81.344 (Effective October 31, 2008).

10.3.1. PSD Applicability Review

The Mont Belvieu Plant is an existing major source with respect to criteria pollutants under the PSD program because potential emissions of one or more criteria pollutants exceed the thresholds listed in 40 CFR §52.21(b)(1)(i) (i.e., more than 250 tpy). PSD permitting requirements apply to a major modification at an existing major stationary source. A major modification is defined in 40 CFR §52.21(b)(2)(i) as any project that would result in a significant net emissions increase of a regulated NSR pollutant, as compared to the significant emission rates (SERs) provided in §52.21(b)(23) and shown in the table below.

Table 10.3-1. Significant Emission Rates

CO (tpy)	NO_2 (tpy)	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)
100	40	25	15	10	40

As shown in the table included at the end of this section, the project emission increases for all non-GHG criteria pollutants are less than their respective SERs. Therefore, the proposed project will not be subject to PSD permitting requirements for non-GHG criteria emissions and the project is subject to the jurisdiction of the TCEQ for minor NSR permitting of such emissions.

In the GHG Tailoring Rule, EPA established a major source threshold of 100,000 tpy CO_2e for new GHG sources and a major modification threshold of 75,000 tpy CO_2e for existing major sources.[14] The Mont Belvieu Plant is an existing major source with respect to GHG emissions under the PSD program because the site currently has a potential to emit greater than 100,000 tpy of CO_2e. Targa has determined that the increase in GHG emissions from the proposed project will exceed 75,000 tpy. As a result, Targa has concluded that the proposed project will be a major modification with respect to GHG emissions and subject to PSD permitting requirements for such emissions.

With a final action published in May 2011, EPA promulgated a FIP to implement the permitting requirements for GHGs in Texas, and EPA assumed the role of permitting authority for Texas GHG permit applications with that action.[15] Therefore, GHG emissions from the proposed project are subject to the jurisdiction of the EPA under authority EPA has asserted in Texas through its FIP for the regulation of GHGs.

Accordingly, Targa is submitting applications to both EPA and TCEQ to obtain the requisite authorizations to construct. The GHG PSD application submitted to EPA is included in Appendix C of this TCEQ NSR permit application for reference.

10.3.2. NNSR Applicability Review

The Mont Belvieu Plant is an existing major source with respect to NO_x and VOC emissions under the NNSR program because sitewide emissions exceed the thresholds listed in 40 CFR §52.21(b)(1)(i) (i.e., more than 25 tpy for a facility in a severe ozone nonattainment area). NNSR applicability is determined based on the increase in emissions of NO_x and VOCs from the proposed project. The increases in VOC and NO_x emissions from the proposed project, without regard to decreases, are greater than five tpy for each pollutant; therefore, contemporaneous netting is required by 30 TAC §116.150(c).

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[14] Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, 75 Fed. Reg. 31,514 (June 3, 2010).

[15] Determinations Concerning Need for Error Correction, Partial Approval and Partial Disapproval, and Federal Implementation Plan Regarding Texas's Prevention of Significant Deterioration Program, 76 Fed. Reg. 25,178 (May 3, 2011).

Targa performed contemporaneous netting calculations for NO_x and VOC, taking into account creditable source emission increases and decreases during the contemporaneous period. The contemporaneous period was taken as the period between the expected start of operation of the proposed Train 5 project and 60 months prior to the expected start of construction date for the proposed project, as defined in 30 TAC §116.12(11). The netting results for each pollutant are compared to the 25 tpy threshold for the severe nonattainment designation. NNSR permitting requirements are not triggered as contemporaneous netting for both pollutants demonstrates less than a 25 tpy increase. The netting analysis is presented in a summary table and netting tables provided at the end of this section.

Targa Midstream Services LLC - Mont Belvieu Plant
PSD & NNSR Summary

PSD Applicability Analysis [1]

FIN	EPN	Description	CO	NO_2	PM	PM_{10}	$PM_{2.5}$	SO_2	CO_2e
			Emissions Increases for Project-Affected Sources (tpy)						
TEG-2	FLR-5	Controlled TEG-2 Emissions	1.68	0.20	-	-	-	-	1,283.79
AU-4	FLR-5	Controlled AU-4 Emissions	5.59	0.65	-	-	-	0.19	11,784.78
F5A	F5A	Hot Oil Heater	23.41	3.16	2.53	2.53	2.53	0.37	74,026.45
F5B	F5B	Hot Oil Heater	23.41	3.16	2.53	2.53	2.53	0.37	74,026.45
FUG-CT-9	FUG-CT-9	Cooling Tower 9	-	-	2.43	0.73	0.73	-	-
Maintenance	FLR-5	Controlled Maintenance Emissions	0.01	0.01	-	-	-	-	303.36
Startup	FLR-5	Controlled Startup Emissions	0.05	0.03	-	-	-	-	280.76
Shutdown	FLR-5	Controlled Shutdown Emissions	0.05	0.03	-	-	-	-	401.13
TK-2	TK-2	Ucarsol Storage Tank	-	-	-	-	-	-	-
FLR-5	FLR-5	Flare Pilot & Supplemental Fuel	16.49	2.02	-	-	-	-	3,561.40
		Total Project Emissions Increase	70.69	9.25	7.49	5.79	5.79	0.93	165,668
		PSD Significant Emission Rate	100	40	25	15	10	40	75,000
		PSD Netting Analysis Needed (Yes/No)?	No	No	No	No	No	No	Yes

[1] Fugitive emissions are not included in PSD applicability determination per 40 CFR 52.28(c)(4)(ii).

NNSR Applicability Analysis

Pollutant	Total Project Emissions Increases (tpy)	Above 5 tpy Netting Threshold?	Net Emission Increase (tpy) [1]	NNSR Threshold	NNSR Review?
VOC	13.20	Yes	20.32	25	No
NO_x	9.25	Yes	-2.23	25	No

[1] The net emission increase is based on the sum of the creditable increase or decrease column of Table 3F.

TCEQ

TABLE 3F
PROJECT CONTEMPORANEOUS CHANGES[1]

Company: Targa Midstream Services LLC	
Permit Application Number: N/A	Criteria Pollutant: NO_x

Project Date[2]		Facility at Which Emission Change Occured[3]		Permit No.	Project Name or Activity	Baseline Period	A Baseline Emissions (tons/year)	B Proposed Emissions (tons/year)	Difference (B-A)[5]	Creditable Decrease or Increase[6]
		FIN	EPN							
1	2/1/2009	F-B	F-B	85385	Furnace B Change	2004-2005	52.00	30.00	-22.00	-22.00
3	4/11/2009	B-09A	B-09A	81524	Temporary Boiler	2007-2008	7.73	-	-7.73	-7.73
4	4/11/2009	B-09B	B-09B	81524	Temporary Boiler	2007-2008	7.73	-	-7.73	-7.73
2	7/15/2009	GT-1	GT-1	84814	CoGen Permit	2007-2008	-	17.01	17.01	17.01
5	7/15/2009	B-09C	B-09C	83115	Temporary Boiler	2007-2008	4.99	-	-4.99	-4.99
6	1/20/2011	AU-1	FLR-1NSCAP	106.261	Amine Treater Temporary		-	0.24	0.24	0.24
7	2/9/2011	AU-1	FLR-1NSCAP	106.261	Amine Treater Temporary		0.24	-	-0.24	-0.24
8	3/30/2011	GLY-2	FLR-1NSCAP	91519	T-14 Expansion Project	2006-2007	-	0.20	0.20	0.20
9	3/30/2011	AU-2	FLR-1NSCAP	91519	T-14 Expansion Project	2006-2007	2.14	1.41	-0.73	-0.73
10	4/18/2011	TEMP-WASH	TEMP-WASH	106.511	Temporary Wash Pump	2009-2010	-	0.53	0.53	0.53
11	10/3/2011	RB2011A	RB2011A	98061	Rental Boiler_2011A	2009-2010	-	4.59	4.59	4.59
12	10/3/2011	RB2011B	RB2011B	98061	Rental Boiler_2011B	2009-2010	-	4.59	4.59	4.59
13	10/28/2011	TEMP-WASH	TEMP-WASH	106.511	Temporary Wash Pump	2009-2010	0.53	-	-0.53	-0.53
14	12/31/2011	RB2011A	RB2011A	98061	Rental Boiler_2011A	2009-2010	4.59	-	-4.59	-4.59
15	12/31/2011	RB2011B	RB2011B	98061	Rental Boiler_2011B	2009-2010	4.59	-	-4.59	-4.59
16	1/24/2012	GS-MSS	GS-MSS	5452	Gasoline Stabilizer		-	0.00	0.00	0.00
17	1/24/2012	GS-MSS	FLR-1NSCAP	5452	Gasoline Stabilizer		-	0.004	0.004	0.004
18	1/24/2012	BOILERS	BOILERS	5452	Gasoline Stabilizer		-	8.36	8.36	8.36
19	8/31/2012*	multiple	FLR-1NSCAP	5452	RTO Installation	2008-2009	23.09	7.00	-16.09	-16.09
20	8/31/2012*	RTO-1	RTO-1	95200	RTO Installation		-	3.85	3.85	3.85
21	8/31/2012*	RTO-2	RTO-2	95200	RTO Installation		-	0.16	0.16	0.16
22	8/31/2012*	AU-3	RTO-2	94872	Train 4 Expansion Project		-	0.16	0.16	0.16
23	5/1/2013*	H-701A	H-701A	94872	Train 4 Expansion Project		-	3.16	3.16	3.16
24	5/1/2013*	H-701B	H-701B	94872	Train 4 Expansion Project		-	3.16	3.16	3.16
25	5/1/2013*	TEG-1	RTO-1	94872	Train 4 Expansion Project		-	<0.001	<0.001	<0.001
26	5/1/2013*	Maintenance	RTO-1	94872	Train 4 Expansion Project		-	<0.001	<0.001	<0.001
27	5/1/2013*	Startup	RTO-1	94872	Train 4 Expansion Project		-	<0.001	<0.001	<0.001
28	5/1/2013*	Shutdown	RTO-1	94872	Train 4 Expansion Project		-	<0.001	<0.001	<0.001
29	TBD	H-XXX	H-XXX	TBD	Purity Propane Project	--	-	11.70	11.70	11.70
30	TBD	AU-4	FLR-5	TBD	Train 5 Expansion Project	-	-	0.65	0.65	0.65
31	TBD	F5A	F5A	TBD	Train 5 Expansion Project	-	-	3.16	3.16	3.16
32	TBD	F5B	F5B	TBD	Train 5 Expansion Project	-	-	3.16	3.16	3.16
33	TBD	TEG-2	FLR-5	TBD	Train 5 Expansion Project	-	-	0.20	0.20	0.20
34	TBD	FLR-5	FLR-5	TBD	Train 5 Expansion Project	-		2.02	2.02	2.02
35	TBD	Maintenance	FLR-5	TBD	Train 5 Expansion Project	-	-	< 0.01	< 0.01	< 0.01
36	TBD	Startup	FLR-5	TBD	Train 5 Expansion Project	-	-	0.03	0.03	0.03
37	TBD	Shutdown	FLR-5	TBD	Train 5 Expansion Project	-	-	0.03	0.03	0.03
									Total	**-2.23**

* Estimated start of operation

1. Individual Table 3Fs should be used to summarize the project emission increase and net emission increase for each criteria pollutant.
2. The start of operation date for the modified or new facilities. Attach Table 4F for each project reduction claimed.
3. Emission Point No. as designated in NSR Permit or Emissions Inventory.
4. All records and calculations for these values must be available upon request.
5. Allowable (column A) - Baseline (column B).
6. If portion of the decrease not creditable, enter creditable amount. If all of decrease is creditable or if this line is an increase, enter column C again.
7. Sum all values for this page.

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TABLE 3F
PROJECT CONTEMPORANEOUS CHANGES[1]

Company: Targa Midstream Services LLC	
Permit Application Number: N/A	Criteria Pollutant: VOC

Project Date[2]		Facility at Which Emission Change Occured[3]		Permit No.	Project Name or Activity	A Baseline Period	B Baseline Emissions (tons/year)	Proposed Emissions (tons/year)	Difference (B-A)[5]	Creditable Decrease or Increase[6]
		FIN	EPN							
1	2/1/2009	F-B	F-B	85385	Furnace B Change	2004-2005	2.75	3.61	0.86	0.86
2	4/11/2009	B-09A	B-09A	81524	Temporary Boiler	2007-2008	1.13	0.00	-1.13	-1.13
3	4/11/2009	B-09B	B-09B	81524	Temporary Boiler	2007-2008	1.13	0.00	-1.13	-1.13
4	7/15/2009	GT-1	GT-1	84814	CoGen Permit	2007-2008	0.00	4.98	4.98	4.98
5	7/15/2009	B-09C	B-09C	83115	Temporary Boiler - removed	2007-2008	1.86	0.00	-1.86	-1.86
6	1/20/2011	AU-1	FLR-1NSCAP	106.261	Amine Treater Temporary	2009-2010	-	0.74	0.74	0.74
7	2/9/2011	AU-1	FLR-1NSCAP	106.261	Amine Treater Temporary		0.74	-	-0.74	-0.74
8	3/30/2011	GLY-2	FLR-1NSCAP	91519	T-14 Expansion Project	2006-2007	-	1.66	1.66	1.66
9	3/30/2011	FUG-FRAC	FUG-FRAC	91519	T-14 Expansion Project	2006-2007	-	1.03	1.03	1.03
10	3/30/2011	CT-7	CT-7	91519	T-14 Expansion Project	2006-2007	-	1.53	1.53	1.53
11	3/30/2011	AU-2	FLR-1NSCAP	91519	T-14 Expansion Project (120 gpm)	2006-2007	5.92	3.97	-1.95	-1.95
12	4/18/2011	TEMP-WASH	TEMP-WASH	106.511	Temporary Wash Pump	2009-2010	-	0.05	0.05	0.05
13	10/3/2011	RB2011A	RB2011A	98061	Rental Boiler_2011A	2009-2010	-	0.53	0.53	0.53
14	10/3/2011	RB2011B	RB2011B	98061	Rental Boiler_2011B	2009-2010	-	0.53	0.53	0.53
15	10/28/2011	TEMP-WASH	TEMP-WASH	106.511	Temporary Wash Pump	2009-2010	0.05	-	-0.05	-0.05
16	12/31/2011	RB2011A	RB2011A	98061	Rental Boiler_2011A	2009-2010	0.53	-	-0.53	-0.53
17	12/31/2011	RB2011B	RB2011B	98061	Rental Boiler_2011B	2009-2010	0.53	-	-0.53	-0.53
18	1/24/2012	FUG-C6	FUG-C6	5452	Gasoline Stabilizer	--	-	1.45	1.45	1.45
19	1/24/2012	GS-MSS	GS-MSS	5452	Gasoline Stabilizer	--	-	0.05	0.05	0.05
20	1/24/2012	GS-MSS	FLR-1NSCAP	5452	Gasoline Stabilizer	--	-	0.03	0.03	0.03
21	1/24/2012	BOILERS	BOILERS	multiple	Gasoline Stabilizer	--	-	2.02	2.02	2.02
22	8/31/2012*	multiple	FLR-1NSCAP	95200	RTO Installation	2008-2009	77.99	30.00	-47.99	-47.99
23	8/31/2012*	RTO-1	RTO-1	95200	RTO Installation	--	-	30.00	30.00	30.00
24	8/31/2012*	RTO-2	RTO-2	95200	RTO Installation	--	-	2.89	2.89	2.89
25	5/1/2013*	AU-3	RTO-2	94872	Train 4 Expansion Project	--	-	0.12	0.12	0.12
26	5/1/2013*	H-701A	H-701A	94872	Train 4 Expansion Project	--	-	0.39	0.39	0.39
27	5/1/2013*	H-701B	H-701B	94872	Train 4 Expansion Project	--	-	0.39	0.39	0.39
28	5/1/2013*	FUG-FRAC2	FUG-FRAC2	94872	Train 4 Expansion Project	--	-	4.59	4.59	4.59
29	5/1/2013*	FUG-CT-8	FUG-CT-8	94872	Train 4 Expansion Project	--	-	7.13	7.13	7.13
30	5/1/2013*	TEG-1	RTO-1	94872	Train 4 Expansion Project	--	-	0.08	0.08	0.08
31	5/1/2013*	Maintenance	RTO-1	94872	Train 4 Expansion Project	--	-	0.13	0.13	0.13
32	5/1/2013*	Maintenance	Maintenance	94872	Train 4 Expansion Project	--	-	0.01	0.01	0.01
33	5/1/2013*	Startup	RTO-1	94872	Train 4 Expansion Project	--	-	0.18	0.18	0.18
34	5/1/2013*	Shutdown	RTO-1	94872	Train 4 Expansion Project	--	-	0.31	0.31	0.31
35	5/1/2013*	Shutdown	Shutdown	94872	Train 4 Expansion Project	--	-	0.07	0.07	0.07
36	5/1/2013*	TK-1	TK-1	94872	Train 4 Expansion Project	--	-	<0.01	<0.01	<0.01
37	TBD	H-XXX	H-XXX	TBD	Purity Propane Project	--	-	0.25	0.25	0.25
38	TBD	FUG-FRACX	FUG-FRACX	TBD	Purity Propane Project	--	-	1.03	1.03	1.03

US EPA ARCHIVE DOCUMENT

TCEQ

TABLE 3F
PROJECT CONTEMPORANEOUS CHANGES[1]

Company: Targa Midstream Services LLC	
Permit Application Number: N/A	Criteria Pollutant: VOC

Project Date[2]		Facility at Which Emission Change Occured[3] FIN	EPN	Permit No.	Project Name or Activity	A Baseline Period	B Baseline Emissions (tons/year)	Proposed Emissions (tons/year)	Difference (B-A)[5]	Creditable Decrease or Increase[6]
39	TBD	AU-4	FLR-5	TBD	Train 5 Expansion Project	--	-	0.06	0.06	0.06
40	TBD	F5A	F5A	TBD	Train 5 Expansion Project	--	-	0.38	0.38	0.38
41	TBD	F5B	F5B	TBD	Train 5 Expansion Project	--	-	0.38	0.38	0.38
42	TBD	FUG-FRAC5	FUG-FRAC5	TBD	Train 5 Expansion Project	--	-	1.38	1.38	1.38
43	TBD	FUG-CT-9	FUG-CT-9	TBD	Train 5 Expansion Project	--	-	7.13	7.13	7.13
44	TBD	TEG-2	FLR-5	TBD	Train 5 Expansion Project	--	-	0.17	0.17	0.17
45	TBD	FLR-5	FLR-5	TBD	Train 5 Expansion Project	--	-	1.49	1.49	1.49
46	TBD	Maintenance	FLR-5	TBD	Train 5 Expansion Project	--	-	0.63	0.63	0.63
47	TBD	Maintenance	Maintenance	TBD	Train 5 Expansion Project	--	-	0.01	0.01	0.01
48	TBD	Startup	FLR-5	TBD	Train 5 Expansion Project	--	-	0.51	0.51	0.51
49	TBD	Shutdown	FLR-5	TBD	Train 5 Expansion Project	--	-	0.99	0.99	0.99
50	TBD	Shutdown	Shutdown	TBD	Train 5 Expansion Project	--	-	0.07	0.07	0.07
51	TBD	TK-2	TK-2	TBD	Train 5 Expansion Project	--	-	<0.01	<0.01	<0.01
									Total **	**20.32**

* Estimated start of operation

** For total emission calculations, emissions represented as less than 0.01 tpy are conservatively assumed to be 0.01 tpy.

1. Individual Table 3Fs should be used to summarize the project emission increase and net emission increase for each criteria pollutant.
2. The start of operation date for the modified or new facilities. Attach Table 4F for each project reduction claimed.
3. Emission Point No. as designated in NSR Permit or Emissions Inventory.
4. All records and calculations for these values must be available upon request.
5. Allowable (column A) - Baseline (column B).
6. If portion of the decrease not creditable, enter creditable amount. If all of decrease is creditable or if this line is an increase, enter column C again.
7. Sum all values for this page.

11. BEST AVAILABLE CONTROL TECHNOLOGY

This section of the permit application evaluates the BACT for all equipment affected by this permit application as set forth in 30 TAC §116.111(a)(2)(C). As previously discussed in Section 10, the potential emission increases of all criteria pollutants are below the PSD and NNSR major modification thresholds and therefore, do not trigger PSD or NNSR Review. As such, the facilities in this application are subject to State BACT review for all contaminants released to the atmosphere.

30 TAC §116.111(a)(2)(c) provides that the proposed project will utilize BACT, with consideration given to the technical practicability and economic reasonableness of reducing or eliminating the emissions from the facility. The following sections discuss how each of the proposed sources meets State BACT.

Tier I BACT involves comparison of proposed emission reductions to those approved in recent permit applications for similar processes or industries. As long as no new technical developments have been made that would allow for more stringent controls, based on economic and technical reasonableness, then the previously approved emission reductions may be considered to meet BACT and no further review is necessary. If Tier I BACT is not met, then a Tier II analysis must be performed.

Tier II BACT involves comparison of emission reductions to those approved in recent permit applications for similar air emission streams in different processes or industries. The Tier II BACT may involve a more detailed analysis of technical practicability across different industries/processes, but should not require a detailed economic analysis. If Tier II BACT is not met, then a Tier III analysis must be performed.

Tier III BACT involves a detailed review of all emission reduction options on both a technical and economic basis. Technical feasibility is demonstrated through previous success of an emission reduction strategy, or engineering evaluation of a new technology. Economic feasibility is demonstrated based on the cost effectiveness of controlling emissions (i.e., the dollars per ton of pollutant emissions reduced).

The emission units subject to the State BACT for the proposed project include the following:

- Amine unit (FIN AU-4, EPN FLR-5);
- TEG dehydration unit (FIN TEG-2, EPN FLR-5);
- Cooling tower (EPN FUG-CT-9);
- Hot oil heaters (EPNs F5A and F5B);
- Ucarsol Storage Tank (EPN TK-2); and
- Fugitive emissions from piping components (EPN FUG-FRAC5);

Emissions also result from the following MSS activities:

- Maintenance emissions to the flare (FIN Maintenance, EPN FLR-5);
- Startup emissions to the flare (FIN Startup, EPN FLR-5);
- Shutdown emissions to the flare (FIN Shutdown, EPN FLR-5);
- Maintenance emissions to the atmosphere (FIN Maintenance, EPN Maintenance); and
- Shutdown emissions to the atmosphere (FIN Shutdown, EPN Shutdown).

The table included at the end of this section provides a summary of TCEQ's Tier I BACT requirements and proposed BACT for normal operations and MSS activities associated with Train 5. As demonstrated in the detailed BACT analysis below, all sources will meet Tier I BACT.

11.1. PROCESS HEATERS

The two natural-gas fired heaters will be subject to BACT review for NO_x, CO, SO_2, PM_{10}, $PM_{2.5}$, and VOC. TCEQ guidance establishes current BACT for NO_x and CO from combustion sources. For process heaters, Tier I BACT is a burner with the best NO_x performance given the burner configuration and gaseous fuel used and 50 ppmv corrected to 3% oxygen for CO. If proposed emissions for NO_x are greater than 0.01 lb NO_x/MMBtu, a case-by-case review is needed.[16]

The new heaters will be equipped with low-NO_x burners and SCR systems. In addition, Targa will utilize good combustion practices and proper heater design to minimize NO_X and CO emissions further. Targa proposes the following emission limits as BACT:

Table 11.1-1. Proposed NO_X and CO emission Limits for Process Heaters

Emission Unit	Maximum Heat Input Rate	Proposed NO_X Emission Limit	Proposed CO Emission Limit
Hot Oil Heater (EPN F5A)	144.45 MMBtu/hr	0.005 lb/MMBtu	0.037 lb/MMBtu
Hot Oil Heater (EPN F5B)	144.45 MMBtu/hr	0.005 lb/MMBtu	0.037 lb/MMBtu

The proposed NO_X and CO emission limits for the two heaters will meet the TCEQ's Tier I BACT requirements.

There is no TCEQ guidance for BACT for PM_{10}, $PM_{2.5}$, VOC, and SO_2 emissions from the process heaters. Targa proposes the use of natural gas as fuel and good combustion practices as BACT for these emissions.

11.2. AMINE UNIT & TEG DEHYDRATOR

The Amine Unit (FIN AU-4) and TEG Dehydrator (FIN TEG-2) will be subject to BACT review for VOC emissions.

There is no TCEQ BACT guidance for amine units. The VOCs removed from the amine vents will be routed to the flare (EPN FLR-5). A DRE of 99% for compounds up to three carbons and 98% otherwise is based on manufacturer guaranteed destruction. Therefore, Targa proposes that routing amine unit emissions to the flare will satisfy BACT requirements.

TCEQ's Tier I BACT for glycol dehydrators requires that VOC emissions from the glycol dehydrator reboiler still vent be routed to either a flare with a 98% DRE or a firebox with 99+% DRE.[17] Targa proposes to route the dehydrator vent streams to the flare, which will achieve a DRE of 99% for compounds up to three carbons and 98% otherwise. Therefore, the flare will meet the TCEQ's Tier I BACT requirements for control of the glycol dehydrator emissions.

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[16] TCEQ Combustion Sources, Current Best Available Control Technology Guidelines for Process Furnaces and Heaters dated 8/1/2011, http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bact/bact_processfurn.pdf

[17] TCEQ Chemical Sources, Current Best Available Control Technology Requirements for Glycol Dehydrator dated 8/1/2011, http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bact/bact_glycoldehyd.pdf

11.3. FLARE

The flare (EPN FLR-5) will be used to destroy the off-gas produced during emergency situations, MSS activities, and during amine and dehydrator venting. Pipeline quality natural gas will be used as pilot gas and as supplemental fuel. The flare will be subject to TCEQ BACT for VOC. TCEQ guidance establishes current BACT for flares, including the minimum requirement of meeting 40 CFR §60.18 (General control device and work practice requirements) with the following control efficiency requirements: [18]

- Destruction efficiency of 99% for compounds up to three carbons;
- Destruction efficiency of 98% for all others; and
- No flaring of halogenated compounds allowed.

The proposed flare will meet 40 CFR §60.18 performance specifications. In addition, the flare will achieve a DRE of 99% for compounds up to three carbons and 98% otherwise. Flaring of halogenated compounds will not be performed. The net heating value of gas combusted in the flare will be greater than 300 Btu/scf, as ensured by mixing supplemental fuel with the amine and dehydrator vent streams. This will promote flame stability and sufficient destruction efficiency.

The flare will be air-assisted and will maintain sufficient exit velocity to meet the 40 CFR §60.18 requirements. In addition, the flare will have proper air assist, which is controlled by adjusting the blower speed, to prevent smoking but not affect the flare destruction efficiency rate (i.e., there will be no visible emissions except as allowed by State and Federal regulation). Finally the flare pilot will be monitored to ensure it remains lit at all times. This satisfies TCEQ's Tier I BACT for VOC emissions from the flare.

11.4. COOLING TOWER

The fugitive emissions from the Cooling Tower (EPN FUG-CT-9) will be subject to TCEQ BACT for VOC and PM emissions. TCEQ Tier I BACT for fugitives is included in the table below. [19]

Table 11.4-1. TCEQ BACT for Cooling Towers

Pollutant	Minimum Acceptable Control
VOC	Non-contact design. Monthly monitoring of VOC in water per Appendix P or approved equivalent – assume all VOC stripped out. Repair identified leaks as soon as possible, but before next scheduled shutdown, or shutdown triggered by 0.08 ppmw cooling water VOC concentration.
PM	Drift eliminators Drift , 0.001%

[18] TCEQ Chemical Sources, Current Best Available Control Technology Requirements for Flares and Vapor Combustors dated 8/1/2011. http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bact/bact_flares.pdf

[19] TCEQ Chemical Sources, Current Best Available Control Technology Requirements for Cooling Towers dated 8/1/2011, http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bact/bact_cooltow.pdf

The cooling tower has a drift rate of 0.0005%, therefore satisfying TCEQ's Tier I BACT for PM. Targa will comply with TCEQ's Tier I BACT for VOC and will repair leaks as soon as possible or will shutdown if the cooling water VOC concentration exceeds 0.08 ppmw.

11.5. ATMOSPHERIC STORAGE TANKS

Targa is proposing to install an Ucarsol atmospheric storage tank, as shown in the table below.

Table 11.5-1. Ucarsol Atmospheric Storage Tank

EPN	Tank Description	TVP (mm Hg)	TVP (psia)
TK-2	Ucarsol Storage Tank	4.8	0.09

For storage tanks with capacity less than 25,000 gallons or vapor pressure less than 0.5 psia, TCEQ's Tier I BACT requires a fixed roof with submerged fill and white or aluminum un-insulated exterior surfaces exposed to the sun.[20] The Ucarsol stored in the tank has a vapor pressure less than 0.5 psia. In addition, this tank will be a fixed roof tank with submerged fill and painted grey or white. Therefore, the storage tank meets TCEQ Tier I BACT requirements.

11.6. FUGITIVE EMISSIONS FROM PIPING COMPONENTS

The fugitive emissions from the piping components (EPN FUG-FRAC5) will be subject to TCEQ BACT for VOC emissions. TCEQ Tier I BACT for fugitives is included in the table below.[21]

Table 11.6-1. TCEQ BACT Summary for Fugitive Emissions

Pollutant	Minimum Acceptable Control	Control Efficiency Details
Uncontrolled VOC emissions < 10 tpy	None	
10 tpy < uncontrolled VOC emissions < 25 tpy	28M leak detection and repair program (LDAR)	75% credit for 28M
Uncontrolled VOC emissions > 25 tpy	28 VHP LDAR	97% credit for valves, 85% for pumps and compressors
VOC vp < 0.002 psia	No inspection required	No fugitive emissions expected
Approved odorous compounds: NH_3, $C1_2$, H_2S, etc.	Audio/Visual/Olfactory (AVO) inspection twice per shift	Appropriate credit for AVO program

The potential uncontrolled VOC annual fugitive emissions will be greater than 25 tpy for the proposed project and therefore, at least a 28 VHP LDAR program is required. Targa will implement a 28 VHP LDAR program for the

[20] TCEQ Chemical Sources, Current Best Available Control Technology Requirements for Storage Tanks dated 8/1/2011, http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bact/bact_tanks.pdf

[21] TCEQ Chemical Sources Current Best Available Control Technology Requirements for Equipment Leak Fugitives dated 8/1/2011, http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bact/bact_fugitives.pdf

proposed project, meeting the BACT requirements for VOC. In addition, Targa will monitor flanges quarterly using OVA at the same leak definition for valves; therefore, the 97% control efficiency may be applied to flanges.

11.7. PLANT-WIDE MSS FUGITIVE EMISSIONS

Plant-wide MSS fugitive emissions are subject to BACT review for VOC. Fugitive emissions result from maintenance and shutdown activities vented directly to the atmosphere. The potential emissions are estimated as less than 0.08 tpy. Given the low annual emission rate for MSS activities, Targa proposes to minimize the duration and frequency of these MSS activities and to route MSS activities to the flare when possible in order to reduce potential fugitive emissions to satisfy BACT requirements.

Summary of TCEQ BACT Requirements and Proposed BACT

Emission Source	Pollutant	TCEQ Tier I BACT	Case-by-Case Review Required?	Case-by-Case Considerations	Proposed BACT
Process Heaters [1] EPNs F5A, F5B	NO_X	Burners with the best NO_x performance given the burner configuration and gaseous fuel used. Case-by-case review necessary if NO_x > 0.01 lb/MMBtu.	No	N/A	0.005 lb/MMBtu Use of low-NO_x burners and SCR.
	CO	50 ppmv corrected to 3% O_2	No	N/A	0.037 lb/MMBtu
	PM_{10}, $PM_{2.5}$, VOC, and SO_2	N/A	Yes	N/A	Use of natural gas as fuel and good combustion practices
Amine Treater FIN AU-4, EPN FLR-5	VOC	N/A	Yes	N/A	Route the amine waste streams to flare with destruction rate efficiency of 99% for C_1-C_3 and 98% for C_4+.
Glycol Dehydrator [2] FIN TEG-2, EPN FLR-5	VOC	Route reboiler stills vent to control (flare or firebox), with 98% DRE for flare or with 99+% DRE for firebox.	No	N/A	Route the dehydrator waste streams to flare with destruction rate efficiency of 99% for C_1-C3 and 98% for C_4+.
Cooling Tower [3] EPN FUG-CT-9	VOC	Non-contact design. Monthly monitoring of VOC in water per Appendix P or approved equivalent – assume all VOC stripped out. Repair identified leaks as soon as possible, but before next scheduled shutdown, or shutdown triggered by 0.08 ppmw cooling water VOC concentration.	No	N/A	Non-contact design. Repair leaks as soon as possible or will shutdown if the cooling water VOC concentration exceeds 0.08 ppmw.
	PM_{10}, $PM_{2.5}$	Drift eliminators Drift , 0.001%	No	N/A	Drift rate of 0.0005%
Flare [4] EPN FLR-5	VOC	Flare required to meet 40 CFR 60.18. Destruction Efficiency: 99% for certain compounds up to three carbons, 98% otherwise. No flaring of halogenated compounds allowed.	No	N/A	Flare will meet 40 CFR 60.18 requirements. In addition, the flare will achieve a destruction efficiency of 99% for compounds up to three carbons and 98% otherwise. Halogenated compounds will not be flared.
Storage Tank [5] EPN TK-2	VOC	Tank capacity < 25 Mgal or Vp < 0.5 psia: Fixed roof with submerged fill. White or aluminum uninsulated exterior surfaces exposed to the sun.	No	N/A	Ucarsol tank will be fixed roof tanks with submerged fill and painted grey/white.
Fugitive Components [6] EPN FUG-FRAC5	VOC	Uncontrolled VOC emissions > 25 tpy: 28 VHP LDAR	No	N/A	28 VHP LDAR program and quarterly OVA monitoring
Fugitive MSS Activities EPNs FLR-5, Maintenance, Shutdown	VOC	N/A	Yes	VOC emissions from all permitted MSS activities are estimated to be 0.08 tpy of VOC.	Minimize the duration and frequency of fugitive MSS activities. Route MSS releases to flare when possible.

[1] TCEQ Combustion Sources, Current Best Available Control Technology Guidelines for Process Furnaces and Heaters dated 8/1/2011.
http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bact/bact_processfurn.pdf

[2] TCEQ Chemical Sources, Current Best Available Control Technology Requirements for Glycol Dehydrator dated 8/1/2011.
http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bact/bact_glycoldehyd.pdf

[3] TCEQ Chemical Sources, Current Best Available Control Technology Requirements for Cooling Towers dated 8/1/2011,
http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bact/bact_cooltow.pdf

[4] TCEQ Chemical Sources, Current Best Available Control Technology Requirements for Flares and Vapor Combustors dated 8/1/2011.
http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bact/bact_flares.pdf

[5] TCEQ Chemical Sources, Current Best Available Control Technology Requirements for Storage Tanks dated 8/1/2011.
http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bact/bact_tanks.pdf

[6] TCEQ Chemical Sources Current Best Available Control Technology Requirements for Equipment Leak Fugitives dated 8/1/2011.
Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000.

12. COMPLIANCE ASSURANCE MONITORING REQUIREMENTS

Per 30 TAC §122.604(b), Compliance Assurance Monitoring (CAM) is required for sources that meet all of the following requirements:

- The emission unit is subject to an emission limitation or standard for an air pollutant (or surrogate thereof) in an applicable requirement
- The emission unit uses a control device to achieve compliance with the emission limitation or standard
- The emission unit has pre-control device potential to emit (PTE) greater than or equal to the amount in tons per year required for a site to be classified as a major source

Exemptions to CAM requirements are listed in 30 TAC §122.604(c) and include the following:

- Emission limitations or standards in NSPS or NESHAP subparts proposed by the U.S. EPA after November 15, 1990
- Emission limitations or standards for which an applicable requirement specifies a continuous compliance determination method, unless the applicable compliance method includes an assumed control device emission reduction factor that could be affected by the actual operation and maintenance of the control device
- Other emission limitations or standards specified as exempt by the U.S. EPA

The Mont Belvieu Plant is located in Chambers County, which has been designated as a severe nonattainment area for the eight-hour ozone standard.[22] The major source threshold for a severe nonattainment area is 25 tpy for VOC emissions. The emissions from piping fugitives (EPN FUG-FRAC5) are the only source with uncontrolled emission greater than major source thresholds. Even if the emissions from piping fugitives were considered an emission unit potentially subject to CAM, the piping fugitives will not use a control device to achieve compliance with any emission limitation or standard. As a result, CAM does not apply. In addition, the fugitive emissions will be subject to NSPS Subpart OOOO, which was proposed after November 1990. Therefore, there are no CAM requirements for the emission sources associated with the proposed project.

[22] Per 40 CFR §81.344 (Effective October 31, 2008).

13. PROFESSIONAL ENGINEER (P.E.) SEAL

The professional engineer (P.E.) seal is included in this section for the proposed project.

FORM PI-1 SECTION X PROFESSIONAL ENGINEER (P.E.) SEAL

I, Paul Greywall, have reviewed the following sections of the attached application for an initial new source review permit submitted by Targa:

Emissions Data

Best Available Control Technology

The capital cost of the project is estimated to be greater than $25,000,000.

The application for initial new source review, as referenced above, was reviewed on the 5th day of March 2012.

Signed:

Date: 3/5/2012

Professional Engineer Registration Number: 105305

APPENDIX A

GRI-GLYCalc Input and Output Files

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: Targa Midstream Services, L.P. - Mont Belvieu Plant - TEG-1
File Name: Z:\CLIENTS\Targa\TX Mont Belvieu\Projects\114401.0169 Train 5 Expansion\GLYCalc\TEG Dehy_Flare_v1.1.ddf
Date: March 08, 2012

DESCRIPTION:

Description: TEG-1 Potential Emissions

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

CONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0004	0.008	0.0015
Ethane	0.2819	6.765	1.2346
Propane	0.0140	0.335	0.0612
Total Emissions	0.2962	7.108	1.2973
Total Hydrocarbon Emissions	0.2962	7.108	1.2973
Total VOC Emissions	0.0140	0.335	0.0612

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0354	0.850	0.1551
Ethane	28.2520	678.047	123.7436
Propane	1.4005	33.611	6.1341
Total Emissions	29.6879	712.509	130.0328
Total Hydrocarbon Emissions	29.6879	712.509	130.0328
Total VOC Emissions	1.4005	33.611	6.1341

FLASH GAS EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0052	0.124	0.0227
Ethane	1.1306	27.134	4.9520
Propane	0.0239	0.573	0.1046
Total Emissions	1.1596	27.831	5.0792
Total Hydrocarbon Emissions	1.1596	27.831	5.0792
Total VOC Emissions	0.0239	0.573	0.1046

FLASH TANK OFF GAS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.5174	12.417	2.2662
Ethane	113.0598	2713.435	495.2019
Propane	2.3874	57.297	10.4567
Total Emissions	115.9646	2783.149	507.9248

Total Hydrocarbon Emissions	115.9646	2783.149	507.9248
Total VOC Emissions	2.3874	57.297	10.4567

EQUIPMENT REPORTS:

CONDENSER AND COMBUSTION DEVICE

Condenser Outlet Temperature:	120.00 deg. F
Condenser Pressure:	60.00 psia
Condenser Duty:	1.42e-001 MM BTU/hr
Produced Water:	35.37 bbls/day
Ambient Temperature:	80.00 deg. F
Excess Oxygen:	15.00 %
Combustion Efficiency:	99.00 %
Supplemental Fuel Requirement:	1.42e-001 MM BTU/hr

Component	Emitted	Destroyed
Methane	1.00%	99.00%
Ethane	1.00%	99.00%
Propane	1.00%	99.00%

ABSORBER

Calculated Absorber Stages:	1.39
Specified Dry Gas Dew Point:	5.50 lbs. H2O/MMSCF
Temperature:	100.0 deg. F
Pressure:	393.0 psig
Dry Gas Flow Rate:	110.0000 MMSCF/day
Glycol Losses with Dry Gas:	1.1417 lb/hr
Wet Gas Water Content:	Saturated
Calculated Wet Gas Water Content:	117.92 lbs. H2O/MMSCF
Calculated Lean Glycol Recirc. Ratio:	3.26 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	4.65%	95.35%
Carbon Dioxide	99.83%	0.17%
Methane	99.99%	0.01%
Ethane	99.96%	0.04%
Propane	99.93%	0.07%

FLASH TANK

Flash Control:	Combustion device
Flash Control Efficiency:	99.00 %
Flash Temperature:	107.0 deg. F
Flash Pressure:	60.0 psig

Component	Left in Glycol	Removed in Flash Gas
Water	99.98%	0.02%
Carbon Dioxide	49.04%	50.96%
Methane	6.41%	93.59%
Ethane	19.99%	80.01%
Propane	36.97%	63.03%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	23.39%	76.61%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%

STREAM REPORTS:

WET GAS STREAM

Temperature: 100.00 deg. F
Pressure: 407.70 psia
Flow Rate: 4.60e+006 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	2.48e-001	5.42e+002
Carbon Dioxide	3.39e-002	1.81e+002
Methane	2.31e+000	4.49e+003
Ethane	9.64e+001	3.51e+005
Propane	9.60e-001	5.13e+003
Total Components	100.00	3.62e+005

DRY GAS STREAM

Temperature: 100.00 deg. F
Pressure: 407.70 psia
Flow Rate: 4.58e+006 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.16e-002	2.52e+001
Carbon Dioxide	3.40e-002	1.81e+002
Methane	2.32e+000	4.49e+003
Ethane	9.67e+001	3.51e+005
Propane	9.62e-001	5.12e+003
Total Components	100.00	3.61e+005

LEAN GLYCOL STREAM

Temperature: 100.00 deg. F
Flow Rate: 2.80e+001 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.90e+001	1.56e+004
Water	1.00e+000	1.58e+002
Carbon Dioxide	1.99e-013	3.14e-011
Methane	1.18e-019	1.86e-017
Ethane	4.23e-007	6.67e-005
Propane	9.77e-010	1.54e-007

Component	Conc.	Loading
Total Components	100.00	1.58e+004

RICH GLYCOL STREAM

Temperature: 100.00 deg. F
Pressure: 407.70 psia
Flow Rate: 2.93e+001 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.50e+001	1.56e+004
Water	4.11e+000	6.75e+002
Carbon Dioxide	1.91e-003	3.14e-001
Methane	3.37e-003	5.53e-001
Ethane	8.60e-001	1.41e+002
Propane	2.31e-002	3.79e+000
Total Components	100.00	1.64e+004

FLASH TANK OFF GAS STREAM

Temperature: 107.00 deg. F
Pressure: 74.70 psia
Flow Rate: 1.46e+003 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.52e-001	1.05e-001
Carbon Dioxide	9.43e-002	1.60e-001
Methane	8.37e-001	5.17e-001
Ethane	9.75e+001	1.13e+002
Propane	1.40e+000	2.39e+000
Total Components	100.00	1.16e+002

FLASH TANK GLYCOL STREAM

Temperature: 107.00 deg. F
Flow Rate: 2.91e+001 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.57e+001	1.56e+004
Water	4.14e+000	6.74e+002
Carbon Dioxide	9.44e-004	1.54e-001
Methane	2.17e-004	3.54e-002
Ethane	1.73e-001	2.83e+001
Propane	8.59e-003	1.40e+000
Total Components	100.00	1.63e+004

FLASH GAS EMISSIONS

Flow Rate: 7.26e+003 scfh
Control Method: Combustion Device
Control Efficiency: 99.00

Component	Conc. (vol%)	Loading (lb/hr)
Water	5.99e+001	2.06e+002

Component	Conc.	Loading
Carbon Dioxide	3.99e+001	3.36e+002
Methane	1.69e-003	5.17e-003
Ethane	1.97e-001	1.13e+000
Propane	2.83e-003	2.39e-002
Total Components	100.00	5.44e+002

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 1.13e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	9.67e+001	5.17e+002
Carbon Dioxide	1.18e-002	1.54e-001
Methane	7.44e-003	3.54e-002
Ethane	3.17e+000	2.83e+001
Propane	1.07e-001	1.40e+000
Total Components	100.00	5.47e+002

CONDENSER PRODUCED WATER STREAM

Temperature: 120.00 deg. F
Flow Rate: 1.03e+000 gpm

Component	Conc. (wt%)	Loading (lb/hr)	(ppm)
Water	1.00e+002	5.16e+002	999854.
Carbon Dioxide	1.19e-003	6.12e-003	12.
Methane	1.43e-005	7.40e-005	0.
Ethane	1.27e-002	6.58e-002	127.
Propane	6.33e-004	3.27e-003	6.
Total Components	100.00	5.16e+002	1000000.

CONDENSER RECOVERED OIL STREAM

Temperature: 120.00 deg. F

The calculated flow rate is less than 0.000001 #mol/hr.
The stream flow rate and composition are not reported.

CONDENSER VENT STREAM

Temperature: 120.00 deg. F
Pressure: 60.00 psia
Flow Rate: 3.81e+002 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	2.87e+000	5.19e-001
Carbon Dioxide	3.35e-001	1.48e-001
Methane	2.20e-001	3.53e-002
Ethane	9.34e+001	2.82e+001
Propane	3.16e+000	1.40e+000
Total Components	100.00	3.03e+001

COMBUSTION DEVICE OFF GAS STREAM

Temperature: 1000.00 deg. F
Pressure: 14.70 psia
Flow Rate: 3.69e+000 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Methane	2.27e-001	3.53e-004
Ethane	9.65e+001	2.82e-001
Propane	3.26e+000	1.40e-002
Total Components	100.00	2.96e-001

APPENDIX B

TCEQ Equipment Tables and Table 2

TABLE 2

MATERIAL BALANCE

This material balance table is used to quantify possible emissions of air contaminants and special emphasis should be placed on potential air contaminants, for example: If feed contains sulfur, show distribution to all products. Please relate each material (or group of materials) listed to its respective location in the process flow diagram by assigning point numbers (taken from the flow diagram) to each material.

LIST EVERY MATERIAL INVOLVED IN EACH OF THE FOLLOWING GROUPS	Point No. from Flow Diagram	Process Rate (lbs/hr or SCFM) standard conditions: 70° F 14.7 PSIA. Check appropriate column at right for each process. [1]	Measurement	Estimation	Calculation
1. Raw Materials - Input					
Raw Liquified Petroleum Gas		100,000 bbl/day		X	
2. Fuels - Input					
Natural Gas		6.99 MMscf/day		X	
3. Products & By-Products - Output					
Ethane		50,000 bbl/day		X	
Propane		25,000 bbl/day		X	
Iso-Butane		5,000 bbl/day		X	
N-Butane		10,000 bbl/day		X	
Natural Gasoline		10,000 bbl/day		X	
4. Solid Wastes - Output					
5. Liquid Wastes - Output					
6. Airborne Waste (Solid) - Output	See Table 1(a)	See Emissions Data section			X
7. Airborne Wastes (Gaseous) - Output	See Table 1(a)	See Emissions Data section			X

[1] Process rates are nominal and will fluctuate based on raw LPG composition.

TABLE 6

BOILERS AND HEATERS

Type of Device: Hot Oil Heaters		Manufacturer:	
Number from flow diagram: F5A and F5B		Model Number:	

CHARACTERISTICS OF INPUT

Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
Natural Gas	See attached emission calculations for Residue Gas composition		Average	Design Maximum
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units) 1,015 Btu/scf	Average _____ scfm* ___% excess (vol)	Design Maximum _______ scfm * ______% excess (vol)

HEAT TRANSFER MEDIUM

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

OPERATING CHARACTERISTICS

Ave. 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.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp °F	scfm
4'-4" x 3' -1"	122 ft	61.85 ft/sec		410	

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Volume)
	See attached emission calculations

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

Also supply an assembly drawing, dimensioned and to scale, in plan, 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 7(b)

02-95

HORIZONTAL FIXED ROOF STORAGE TANK SUMMARY

I. ***Tank Identification*** (*Use a separate form for each tank*).

1. Applicant's Name: Targa Midstream Services LLC
2. Location (*indicate on plot plan and provide coordinates*): ____________
3. Tank No. TK-2 4. Emission Point No. TK-2
5. FIN TK-2 CIN ____________
6. Status: New tank [X] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ____________

II. ***Tank Physical Characteristics***

1. Dimensions
   a. Shell Length : ________ ft.
   b. Diameter: ________ ft.
   c. Nominal Capacity or Working Volume: ________ gallons.
   d. Turnovers per year: ________
   e. Net Throughput : ________ gallons/year.
   f. Maximum Filling Rate: ________ gallons/hour.
   g. Is the tank underground? Yes [ ] No [X]
2. Paint Characteristics
   a. Shell Color/Shade : White/White [ ] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [X] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ________)
   b. Shell Condition : Good [X] Poor [ ]

3. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve			-0.03	atmosphere
Pressure Vent Valve		0.03		
Vacuum Vent Valve				
Open Vent Valve				

Permit No. ______________________   Tank No. EPN TK-2

III. ***Liquid Properties of Stored Material***

1. Chemical Category: Organic Liquids [X] Petroleum Distillates [ ] Crude Oils [ ]
2. Single or Multi-Component Liquid
   Single [X] *Complete Section III.3*
   Multiple [ ] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: Ucarsol
   b. CAS Number: ___________________
   c. Average Liquid Surface Temperature: __________ °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: _______ psia.
   e. Liquid Molecular Weight: ___________
4. Multiple Component Information
   a. Mixture Name: ____
   b. Average Liquid Surface Temperature: _________ °F.
   c. Minimum Liquid Surface Temperature: _________ °F.
   d. Maximum Liquid Surface Temperature: _________ °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: 1.93E-4 psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: _________ psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: _________ psia.
   h. Liquid Molecular Weight: ____________
   i. Vapor Molecular Weight: ____________

j. Chemical Components Information

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight

TABLE 8

FLARE SYSTEMS

Number from Flow Diagram	Manufacturer & Model No. (if available)
EPN FLR-5	

CHARACTERISTICS OF INPUT

Waste Gas Stream	Material	Min. Value Expected	Ave. Value Expected	Design Max.
		(scfm [68°F,14.7 psia])	(scfm [68°F, 14.7 psia])	(scfm [68°F, 14.7 psia])
	1. TEG-2 waste streams	See attached emission calculations for details		
	2. AU-4 waste streams			
	3. Maintenance			
	4. Startup			
	5. Shutdown			
	6.			
	7.			
	8.			
% of time this condition occurs				

	Flow Rate (scfm [68°F, 14.7 psia])		Temp. °F	Pressure (psig)
	Minimum Expected	Design Maximum		
Waste Gas Stream	See attached emission calculations for details			
Fuel Added to Gas Steam				

	Number of Pilots	Type Fuel	Fuel Flow Rate (scfm [70°F & 14.7 psia]) per pilot
	4	Natural Gas	0.833 scfm/pilot

For Stream Injection	Stream Pressure (psig)		Total Stream Flow	Temp. °F	Velocity (ft/sec)
	Min. 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) 185 ft	Flare tip inside diameter (ft) 5.5 ft
Capital Installed Cost $____________	Annual Operating Cost $______________

Supply an assembly drawing, dimensioned and to scale, to show clearly the operation of the flare system. Show interior dimensions and features of the equipment necessary to calculate its performance. Also describe the type of ignition system and its method of operation. Provide an explanation of the control system for steam flow rate and other operating variables.

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APPENDIX C

GHG PSD Permit Application