TARGA

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November 8, 2012

United States Environmental Protection Agency, Region 6
Ms. Aimee Wilson
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

Re: ***Response to GHG PSD Permit Application Incompleteness Determination Letter***
Targa Midstream Services LLC
Mont Belvieu Fractionator – Train 5

Dear Ms. Wilson:

Please find Targa Midstream Services LLC's (Targa's) response to your letter dated May 15, 2012, regarding additional information requested to our permit application for our proposed Mont Belvieu Fractionator Train 5. Below please find the questions followed by Targa's written response..

General

1. *The application does not provide the production volume for the proposed new fractionation train. How many tons per year of ethane, propane, butane, and natural gas will be produced?*

   The proposed fractionation train is designed to handle 100,000 barrels per day (BPD) of inlet liquid. The actual production rates will fluctuate based on customer demand and inlet composition. Approximate, average liquid products based on 100,000 BPD of inlet:
   - Ethane = 50,000 BPD
   - Propane = 22,000 BPD
   - iC4 = 5,000 BPD
   - nC4 = 12,000 BPD
   - Natural Gasoline = 11,000 BPD

2. *Please revise the process flow diagram, Section 6 of figure 6.1, to indicate the emission point numbers (EPN) for each emission unit.*

   Targa has provided a revised process flow diagram indicating the emission point numbers for each emission unit in Attachment 1 of this letter.

3. *There is no recommended monitoring, recordkeeping, and reporting for the CO_2 emissions. Does Targa have a preferred monitoring method for the hot oil heaters or flare?*

   Targa intends to install a separate fuel flow meter for each of the following combustion sources: hot oil heaters (EPN F5A, F5B) and flare (EPN FLR-5). The proposed monitoring methods for the flare are provided in the response to Item #6 of this letter.

4. *Will the waste gas from the amine unit and the TEG dehydrator be monitored using online instrumentation to determine the composition and the high heat value?*

   Targa will not install online instrumentation to determine composition or high heat value. Instead, at least once per quarter, Targa will sample and analyze the waste gas for composition. This analysis is considered to be representative of the gas streams for the quarter during which it was taken and will be used to estimate the amine unit vent gas and TEG dehydration unit regenerator vent gas composition, Higher Heating Value (HHV), and Lower Heating Value (LHV).

5. *Please provide an additional impacts analysis as required by 40 CFR 52.21(o). Note that the depth of your analysis will generally depend on existing air quality, the quantity of emissions, and the sensitivity of local soils, vegetation, and visibility in the impact area of your proposed project. In your analysis, please fully document all sources of information, underlying assumptions, and any agreements made as a part of the analysis.*

   According to 40 CFR 52.21(o):

   > *"Additional impact analyses. (1) The owner or operator shall provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the source or modification and general commercial, residential, industrial and other growth associated with the source or modification. The owner or operator need not provide an analysis of the impact on vegetation having no significant commercial or recreational value.*
   > *(2) The owner or operator shall provide an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial and other growth associated with the source or modification.*
   > *(3) Visibility monitoring. The Administrator may require monitoring of visibility in any Federal class I area near the proposed new stationary source for major modification for such purposes and by such means as the Administrator deems necessary and appropriate."*

   Targa will be submitting a Biological Assessment (BA) in support of this application. This assessment will include an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the source or modification. Demonstration for compliance with the national Ambient Air Quality Standards (NAAQS) is being evaluated and will be submitted to the Texas Commission on Environmental Quality (TCEQ) in the near future.

<u>BACT Analysis</u>

6. *Annual ton per year emission limits, for each emission unit, are not considered BACT limits. BACT limits for GHG emission units should be output based limits preferably associated with the efficiency of individual emission units. Please propose short-term emission limitations or efficiency based limits for all emission sources. For the emission sources where this is not feasible, please propose an operating work practice standard.*

Please provide detailed information that substantiates any reasons for infeasibility of a numerical limit.

Heaters (EPNs F5A and F5B)

The BACT limits for GHG emission units have been updated to include the efficiency of the unit based on the plant natural gas throughput capacity. The Mont Belvieu Fractionator will be designed to handle an inlet gas rate of 100,000 bbl per day (bbl/day). The updated limit below illustrates the calculation methodology and the efficiency of the heaters in terms of the potential plant throughout (lb/bbl):

$$\left(16{,}901.02\frac{lb}{hr}+16{,}901.02\frac{lb}{hr}\right)\div 100{,}000\frac{bbl}{day}\times 24\frac{hr}{day}=8.11\frac{CO_2e\quad lb}{bbl}$$

Thermal Oxidizer (EPNs RTO-5)

A short term emission limit for BACT is not feasible for this source because the majority of GHG emissions are not directly related to the operation of the Thermal Oxidizer (TO). The majority of the GHG emissions emitted from the TO are associated with the amine vent stream. The amine unit is used to remove CO_2 in order to meet product specification limits. Because the amine unit is designed to remove CO_2 from the ethane product, the generation of CO_2 is inherent to the process, and a reduction of the CO_2 emissions by process changes would only be achieved by a reduction in the process efficiency and would result in more CO_2 in the product stream, therefore the following operating work practices are proposed for the TO:

- The TO will designed to combust low-VOC concentration waste gas from the amine unit vent stream.
- For burner combustion, the natural gas fuel usage is recorded using a flow meter
- Waste gas will be sampled and analyzed on a quarterly basis for composition.
- The flowrate of the waste gas combusted shall be measured and recorded using a flow meter.
- Periodic maintenance will be performed at least annually on the TO or more often as recommended by the manufacturer.
- Targa will install and maintain a temperature monitor in the combustion chamber to record the combustion temperature. Targa would like the minimum combustion temperature to be determined during the initial stack test. Targa will maintain that temperature at all times when processing waste gas from the amine unit in the thermal oxidizer to ensure proper destruction efficiency. Targa will install and maintain a temperature recording device with an accuracy of either ± 0.75 percent of the temperature being measured expressed in degrees Celsius but no more accurate than ± 2.5 °C.
- Targa requests the continuous temperature monitor be based on a minimum of 1 reading per 15 minutes, reduced to hourly averages.

Flare (EPN FLR-5)

A short term emission limit for BACT is not feasible for this source because the majority of GHG emissions are not directly related to the operation of the flare. The majority of the GHG emissions emitted from the flare are associated with the dehydrator vent stream. The dehydrator unit is used to remove water from the gas stream in order to meet pipeline quality natural gas specifications. Because the dehydrator unit is designed to remove water from the product stream, gas that is entrained in the TEG is emitted to the atmosphere during regeneration of the TEG, the emission of CO_2 is inherent to the process since it is entrained in the TEG, and a reduction of the CO_2 emissions by process changes would only be achieved by a reduction in the process efficiency of removing water from the gas, which then would not meet product specifications. In addition to controlling the TEG unit, the flare controls maintenance, startup, and shutdown (MSS) emissions, which are an intermittent source. Therefore, due to these two different processes that occur at the flare, the following operating work practices are proposed:

- Flare shall have a minimum destruction and removal efficiency (DRE) of 98% based on flowrate and gas composition measurements as specified in 40 CFR Part 98 Subpart W §98.233(n).
- The flare shall be designed and operated in accordance with 40 CFR 60.18 including specifications of minimum heating value of the waste gas, maximum tip velocity, and pilot flame monitoring.
- An infrared monitor is considered equivalent to a thermocouple for flame monitoring purposes.
- Waste gas will be collected with a composite sampler and analyzed monthly to determine composition of gas to the flare.
- The flowrate of the waste gas combusted shall be measured and recorded using a flow meter.
- Targa proposes to limit MSS activities and flaring events to minimize GHG emissions from this source
- Targa proposes the implementation of good combustion practices as noted in the initial application.

<u>Fugitives (EPN FUG-FRAC5)</u>
A short term emission limit for BACT is not feasible for this source because fugitive emissions are based on estimates and are intermittent sources; therefore the following operating work practices are proposed:

- Targa will implement 28LAER program to control fugitive emissions.
- Targa intends to install all air driven pneumatic controllers at the plant.

7. *The application provides a five-step BACT analysis for Carbon Capture and Sequestration (CCS) and concludes that the use of this technology is technically feasible for the amine units, and technically infeasible for all other emission sources. Why did Targa not consider the use of CCS for emission s from the TEG dehydrator feasible? A cost analysis is provided for the amine units. If CCS is feasible for the TEG dehydrator, please revise the cost analysis accordingly. Please indicate the equipment needed to implement CCS, and the costs of such equipment. Also, a comparison of the cost of CCS to the current project's annualized cost needs to be provided.*

Targa has provided a comparison of the currently estimated cost (only installation of the pipeline) to the current project's annualized cost in Attachment 2. If this is not sufficient to demonstrate that the project is not economically feasible, Targa will then provide the additional cost estimates for installing equipment at the site to get the amine and glycol vents into the pipeline.

8. *The current BACT analysis does not appear to provide adequate information in the five-step BACT analysis for the hot oil heaters, amine unit, TEG dehydrator, flare, and fugitives. Step 2 does not provide detailed information on the energy efficiency measures for the two hot oil heaters. The heater BACT analysis on page 30, states that efficient heater design will be used. Please detail what design measures will improve the efficiency of the heaters, and how the efficiency compares to other hot oil heaters. In Step 3, the applicant should provide information on control efficiency, expected emission rate, and expected emission reductions. The applicant should provide comparative benchmark data to indicate other similar industry operating or designed units and compare the design efficiency of this process to other similar or equivalent processes. The applicant should then use this information to rank the control technologies. A comparison of equipment energy efficiencies is necessary to ensure that the most energy efficiency equipment and control technologies are selected. Please provide an analysis that discusses the efficiency of the heaters and why they were selected. This information is then also available to use in determining BACT limits for the emission units for which these technologies are applied in Step 5. Where appropriate, net output-based standards provide a direct measure of the energy efficiency of an operation's emission-reducing efforts. For example, the energy efficiency of the heaters should be tied to a BACT limit. This limit could be established in pounds of CO_2 per MMBtu produced or some other appropriate efficiency measure. Targa should supplement the BACT analysis to provide all necessary information required in Steps 2, 3, and 4 of the five-step BACT analysis.*

   Targa has revised the 5 Step BACT write-up in Section 10 of the application. Please see the revised BACT included as Attachment 3 of this letter. Question 6 above has the BACT limits for these emission sources.

9. *The BACT analysis, page 31 of the permit application, for the Amine Unit and TEG Dehydrator shows that a flare will be used to control the emissions from the waste gases. The emissions data included in the permit application indicates a 99% DRE for the flare. Please explain why a thermal oxidizer (T)) or a regenerative thermal oxidizer (RTO) was not considered as part of the BACT analysis for the amine unit and TEG dehydrator.*

   Targa has updated the BACT analysis to add a thermal oxidizer to the list of possible control technologies for controlling methane emissions from the Amine Unit and TEG unit. The Amine Unit will be routed to a RTO (EPN RTO-5) and the TEG unit will be routed to the flare (EPN FLR-5). Please see the revised BACT for this project included as Attachment 3.

10. *The BACT analysis, on page 29 section 11.2.1.4 of the permit application, for the hot oil heaters indicates that oxygen monitors and intake air flow monitors will be used to optimize the fuel/air mixture. Is there an optimum range of where the fuel/air mixture ratio will be maintained?*

Targa has updated the BACT analysis to remove oxygen trim controls which include oxygen monitors and intake low monitors as GHG control option. The updated BACT is included as an attachment to this letter. Oxygen trim controls are used on forced draft heaters that monitor stack oxygen concentration and automatically adjust the inlet air at the burner for optimum efficiency. Targa is proposing induced draft heaters that do not have any sort of automatic control of the air flow into the burners; therefore oxygen trim controls are not technically feasible on these types of heaters.

11. *The BACT analyses, on pages 36 and 37 of the permit application, for fugitive emissions indicate that the TCEQ 28VHP, LDAR program will be used, and that this program will reduce the emissions up to 97% for most components, but only 30% for flanges and connectors. However, the five –step BACT analyses requires the top control for reducing fugitive emissions and leaks be considered. Was the TCEQ 28LAER LDAR program considered in the BACT analysis? The 28LAER LDAR program achieves up to 97% reduction of emissions from flanges and connectors. What analysis was performed with respect to possible equipment designs such as welded connectors instead of flanges, monitoring of leaks from flanges, and the latest technology devices for detecting fugitive emissions? Please further refine the BACT analyses for fugitive emissions.*

Targa has revised the BACT steps in the application for the fugitive sources to include 28LAER as a possible control option. Targa agrees to implement 28LAER monitoring program as BACT which is the top-ranking LDAR program under Step 3.

As part of the above changes, Targa has revised the control device on the amine treater vent stream to be controlled by a regenerative thermal oxidizer (RTO) instead of the flare. The revisions to the permit application and emission rate calculations are included in Attachment 3.

Should you need additional information, please feel free to contact me at (713) 584-1422 or by email at mroberts@targaresources.com.

Sincerely,

Melanie Roberts
Environmental Manager
Targa Midstream Services LLC

Attachments

cc: Hunter Battle, Vice President – Targa (via email)
Dena Taylor, Targa Senior ES&H Specialist Mont Belvieu (via email)
Environmental Files

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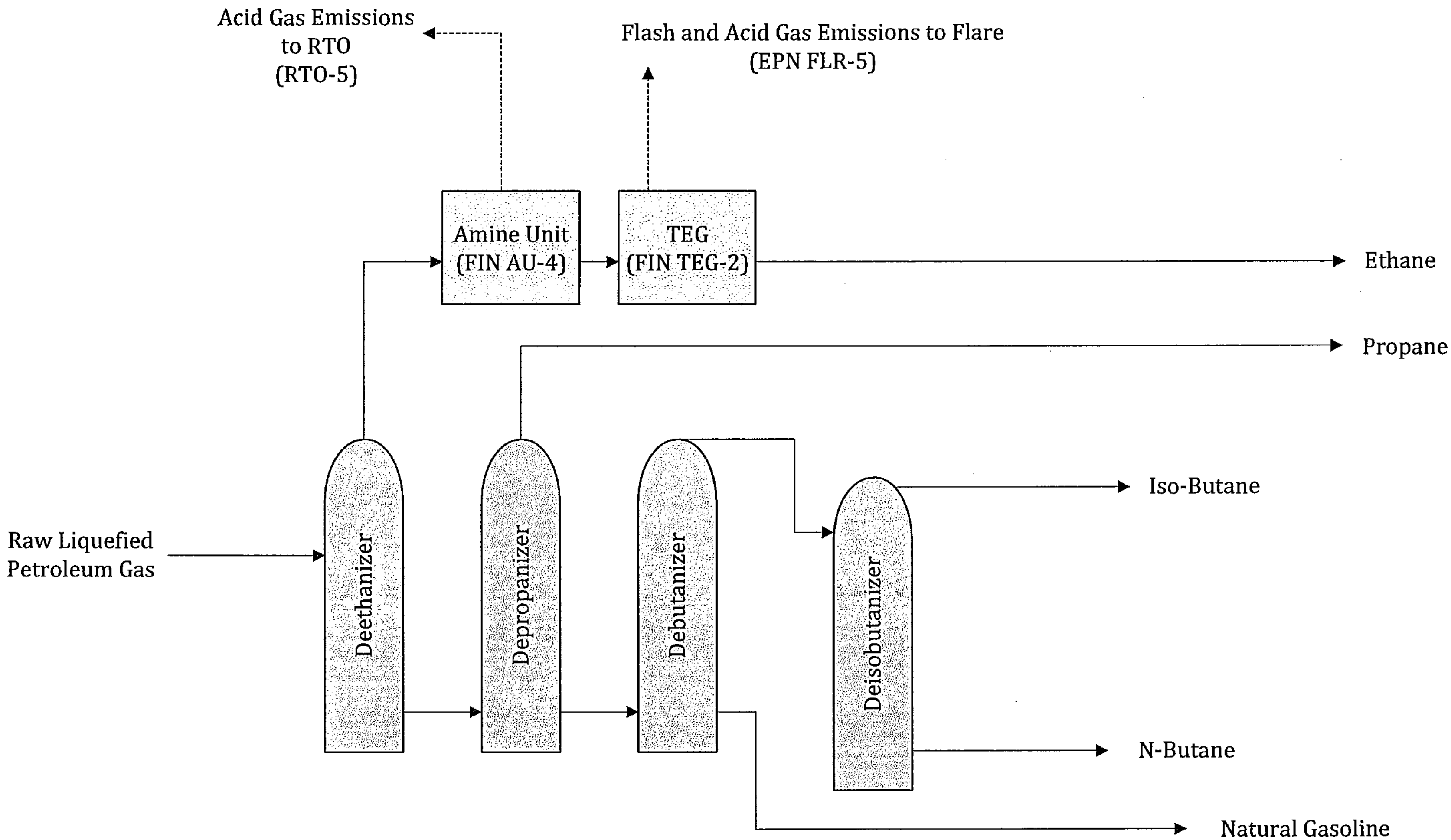
ATTACHMENT 1

Updated PFD with EPN Designation

Figure 6.1 - Train 5 Process Flow Diagram



Emissions

Petroleum Gas

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

ATTACHMENT 2

Carbon Capture Annualized Cost Estimation

Cost Estimation for Transfer of CO2 via Pipeline - Amine Vent and Dehydration Vent

CO2 Pipeline and Emissions Data

Parameter	Value	Units
Minimum Length of Pipeline	25	miles
Average Diameter of Pipeline	8	inches
CO2 emissions from vents	11,776.76	tons/year
CO2 capture efficiency	90%	
Captured CO2	10,599.08	tons/year

CO2 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 D^2 + 686.7 x D + 26,960)	$2,514,139.89
Labor	$ Diameter (inches), Length (miles)	$341,627 + $1.85 x L x (343.2 x D^2 + 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	
CO_2 Surge Tank	$	$1,150,636.00	$1,150,636.00
Pipeline Control System	$	$110,632.00	$110,632.00
		Operation & Maintenance (O&M)	
Fixed O&M	$/mile/year	$8,632.00	$213,210.40
		Total CCS Cost	$17,988,948.68

Amortized CCS Cost

Equipment Life (years)[2]	10
Interest rate	0.07
Capital Recovery Factor (CRF)[3]	0.142
Total Capital Investment (TCI)	$17,775,738.28
Amortized Installation Cost (TCI*CRF)	$2,524,154.84
Total CCS Annualized Cost	**$2,737,365.24**

Amortized Project Cost (without CCS)

Equipment Life[2]	20
Interest rate	0.07
Capital Recovery Factor (CRF)[3]	0.094
Total Capital Investment (TCI)	$385,000,000.00
Amortized Installation Cost (TCI*CRF)	$36,190,000.00
Annual Operating Cost Estimation	$6,000,000.00
Total Project Annualized Cost	**$42,190,000.00**

[1] Cost estimation guidelines obtained from "Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs", DOE/NETL-2010/1447, dated March 201

[2] Pipeline life is estimated at 10 years due to extreme acidic conditions of CO2 stream.

[3] Capital Recovery Fraction = Interest Rate x (1+ Interest Rate) ^ Pipeline Life) / ((1 + Interest Rate) ^ Pipeline Life - 1)

[4] This cost estimation does not include capital and O&M costs associated with the compression equipment or processing equipment associated with CCS.

ATTACHMENT 3

Revised Application Report
Section 1
Section 5
Section 7
Section 8
Section 11

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
- Regenerative Thermal Oxidizer
- 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

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

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.

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 a regenerative thermal oxidizer (RTO). 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]	5,820	0.16	0.02	5,830
RTO-5	11,768	0.08	0.03	11,779
AU-4	29.79	0.002	0	30.02
FUG-FRAC5	0.01	0.11	0	2.33
Uncontrolled MSS Emissions to Atmosphere	0	0.08	0	1.69
Total Project Emissions	165,526	3.22	0.33	165,696

[a] GHG emissions from the TEG 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.

[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).

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.

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 RTO (Emission Point Number [EPN] RTO-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.

7. GHG EMISSIONS DATA

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 RTO-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:

$$\begin{aligned} CO_2\text{e Hourly Emission Rate } \left(\frac{\text{lb}}{\text{hr}}\right) \\ &= CO_2 \text{ Hourly Emission Rate } \left(\frac{\text{lb}}{\text{hr}}\right) \times CO_2 \text{ GWP} + CH_4 \text{ Hourly Emission Rate } \left(\frac{\text{lb}}{\text{hr}}\right) \times CH_4 \text{ GWP} \\ &+ N_2O \text{ Hourly Emission Rate } \left(\frac{\text{lb}}{\text{hr}}\right) \times N_2O \text{ GWP} \end{aligned}$$

[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 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 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 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:

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

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

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 output for the dehydrator waste stream, 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 stream 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).

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

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):

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

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

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

7.3. REGENERATIVE THERMAL OXIDIZER

The RTO (EPN RTO-5) will be used to control emissions from the amine unit. GHG emissions of CO_2, CH_4, and N_2O from the RTO will result from the combustion of the amine still vent (EPN AU-4) waste stream. Additionally, the RTO will utilize a gas-fired burner system during startup.

RTO Normal Operations

Uncontrolled GHG emissions from the amine still vent are estimated data based on similar operations at the facility. The waste stream rates and characteristics are used as the gas inlet to the RTO.

Hourly Emissions of Combusted CO_2, CH_4, and N_2O

Controlled hourly emission rates for CO_2 and CH_4 from the RTO are estimated using the inlet to RTO data from data from similar operations at the facility and the guaranteed destruction efficiency.

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[8] 40 CFR §98.233(z)(2)(iii).

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

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

Hourly N_2O emission rates are estimated using Equation W-40 in 40 CFR Subpart W for combustion units that combust process vent gas, as shown in the following equation:[9]

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

The process gas higher heating value (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.

Hourly Emissions from Conversion to CO_2

In addition to emissions from combusted CO_2, CH_4, and N_2O, additional GHG emissions will result from the conversion of carbon atoms in the fuel 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 98 Subpart W.[10] 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):

$$\text{Converted CO}_2\text{ Hourly Emission Rate} = \text{Inlet to RTO}\left(\frac{\text{lb}}{\text{hr}}\right) \text{ x Carbon Count x Desruction Rate Efficiency (\%)}$$

Annual Emissions

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

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

RTO Startup Operations

The RTO may periodically be shutdown for planned maintenance activities. The RTO will utilize a gas-fired burner system (EPN RTO5-MSS) to bring the RTO up to combustion temperature during startup. After the system has reached temperature, the burners will be shut off and the system will function using the energy content of the amine waste streams alone to support combustion. Emissions from the startup burner system will result from the

[9] 40 CFR §98.233(z)(2)(vi).

[10] 40 CFR §98.233(z)(2)(iii).

combustion of pipeline quality natural gas. No emissions are expected from the RTO during shutdown or maintenance activities.

GHG emissions are estimated based on proposed equipment specifications as provided by the manufacturer and the default emission factors in the EPA's Mandatory Greenhouse Reporting Rule and as shown in **Error! Reference source not found.**.[11]

Hourly emission rates for CO_2, CH_4, and N_2O are based on the heat input rating (MMBtu/hr) for the RTO startup burner. Annual emission rates are estimated based on hourly emissions and the expected startup duration frequency. The following equations are used to estimate hourly and annual CO_2, CH_4, and N_2O emission rates from the RTO startup burner:

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

$$\begin{aligned}&\text{Annual Emission Rate (tpy)}\\ &= \text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Hours per Event}\left(\frac{\text{hr}}{\text{event}}\right) \times \text{Events per Year}\left(\frac{\text{event}}{\text{yr}}\right) \times \left(\frac{\text{ton}}{\text{2,000 lb}}\right)\end{aligned}$$

7.4. 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.[12] Targa has selected to implement the 28 LAER 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.

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:

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

[11] 40 CFR Subpart C, Tables C-1 and C-2.

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

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:

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

7.5. 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:

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

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

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:

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

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)**	**RTO-5 Regenerative Thermal Oxidizer Emissions (RTO-5)**	**RTO Startup Emissions (RTO5-MSS)**	**Amine Still Vent Emissions During RTO Downtime Emissions (AU-4)**	**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	2,686.29	233.78	2,482.57	16,884.46	16,884.46	2.35E-03	812.31	20,279.46	-	41,017.32	41,465.66	-	60,555.24
CH_4	5.53E-03	0.02	4.40E-03	0.91	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	4.40E-04	--	0.03	0.03	-	1.53E-03	2.72E-04	-	6.48E-04	1.37E-03	-	0.08
CO_2e	293.10	2,688.70	234.01	2,501.66	16,901.02	16,901.02	0.53	813.10	20,312.49	66.66	41,087.42	41,534.48	155.85	60,645.64
lb CO_2/bbl[2]	--			--	4.06	4.06	--	--	--	--	--	--	--	8.11

[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

[2] Greenhouse Gas Limit (lb CO_2/ bbl) is based on the CO_2 Hourly Emissions Rate and the proposed plant throughput. The proposed fractionation train is designed to handle 100,000 bbl/day of inlet liquid. An example calculation is provided below.

$$\text{Greenhouse Gas Limit (lb } CO_2\text{/bbl)} = \frac{16{,}884.46 \text{ lb}}{\text{hr}} \left| \frac{\text{day}}{100{,}000 \text{ bbl}} \right| \frac{24 \text{ hrs}}{\text{day}} = \frac{4.06 \text{ lb CO2}}{\text{bbl}}$$

Summary of GHG Annual Emissions

	Annual Emissions (tpy)													
GHG Pollutants	**Controlled TEG-2 Emissions (FLR-5)**	**RTO-5 Regenerative Thermal Oxidizer Emissions (RTO-5)**	**RTO Startup Emissions (RTO5-MSS)**	**Amine Still Vent Emissions During RTO Downtime Emissions (AU-4)**	**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	11,765.94	2.81	29.79	73,953.92	73,953.92	0.01	3,557.92	302.95	-	280.24	400.59	-	165,526.65
CH_4	0.02	0.08	5.28E-05	1.66E-03	1.39	1.39	0.11	0.07	0.02	0.03	0.02	0.03	0.05	3.22
N_2O	0.02	0.03	5.28E-06	-	0.14	0.14	-	6.70E-03	6.17E-06	-	1.85E-05	1.88E-05	-	0.33
CO_2e	1,283.79	11,776.52	2.81	30.02	74,026.45	74,026.45	2.33	3,561.40	303.36	0.65	280.76	401.13	1.04	165,696.70

[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).

RTO (EPN RTO5-MSS)

RTO Emissions - Greenhouse Gases - Startup [1]

Input Data

Startup Burner Size =	2	MMBtu/hr
Startup Event Duration =	2	hr/event
Startup Event Frequency =	12	events/yr

Natural Gas External Combustion Greenhouse Gas Emission Factors

Units [2]	CO_2	CH_4	N_2O
kg/MMBtu	53.02	1.0E-03	1.0E-04
GWP [3]	1	21	310
lb/MMBtu [4]	116.89	2.20E-03	2.20E-04

[1] There will be GHG emissions associated with using a gas-fired burner system to bring the unit up to combustion temperature during startup.
The startup burner will combust pipeline quality sweet natural gas
After the system has reached temperature, the burner will be shut off and the system will function using the energy content of the waste stream alone to support combustion.

[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) = $\frac{53.02\ \text{kg}}{\text{MMBtu}} \times \frac{2.2046\ \text{lb}}{\text{kg}} = \frac{116.89\ \text{lb}}{\text{MMBtu}}$

Compound	RTO Emissions [1, 2, 3]	
	(lb/hr)	(tpy)
CO_2	233.78	2.81
CH_4	4.40E-03	5.28E-05
N_2O	4.40E-04	5.28E-06
CO_2e	234.01	2.81

[1] Maximum Potential Hourly Emission Rate (lb/hr) = Startup Burner Size (MMBtu/hr) x Emission Factor (lb/MMBtu)

Example CO_2 Hourly Emission Rate (lb/hr) = $\frac{2\ \text{MMBtu}}{\text{hr}} \times \frac{116.89\ \text{lb}}{\text{MMBtu}} = \frac{233.78\ \text{lb}}{\text{hr}}$

[2] 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) = $\frac{233.78\ \text{lb}}{\text{hr}} \times 1 + \frac{4.40\text{E-03}\ \text{lb}}{\text{hr}} \times 21 + \frac{4.40\text{E-04}\ \text{lb}}{\text{hr}} \times 310 = \frac{234.01\ \text{lb}}{\text{hr}}$

[3] Maximum Potential Annual Emission Rate (tpy) = Hourly Emission Rate (lb/hr) x Startup Event Duration (hr/event) x Startup Event Frequency (events/yr) x (1 ton / 2,000 lb)

Example CO_2 Annual Emission Rate (tpy) = $\frac{233.78\ \text{lb}}{\text{hr}} \times \frac{2\ \text{hr}}{\text{event}} \times \frac{12\ \text{events}}{\text{yr}} \times \frac{1\ \text{ton}}{2{,}000\ \text{lb}} = \frac{2.81\ \text{ton}}{\text{yr}}$

Targa Midstream Services LLC - Mont Belvieu Plant
RTO Emission Calculations

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 RTO (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	98%	0.14	2.76E-03	0.01	0.14	0.59
	Ethane	2	98%	24.65	--	--	48.31	211.61
	Propane	3	98%	0.33	--	--	0.97	4.24
	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	98%	0.77	1.54E-02	0.07	0.76	3.31
	Ethane	2	98%	76.85	--	--	150.62	659.73
	Propane	3	98%	0.99	--	--	2.91	12.75
	Ucarsol AP-810	5	98%	6.65E-05	--	--	3.26E-04	1.43E-03

Total GHG Emissions [7]	(lb/hr)	(tpy)
CO_2	2,686.29	11,765.94
CH_4	1.82E-02	0.08
N_2O	0.01	0.03
CO_2e	2,688.70	11,776.52

[1] Per Manufacturer specification sheet provided by Ms. Melanie Roberts, Targa, to Ms. Whitney Boger, Trinity, on September 28, 2012.

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

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

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

Example Controlled Methane Hourly Emission Rate (lb/hr) = $\frac{0.14\ \text{lb}}{\text{hr}} \left| \frac{(100 - 98\%)}{100} \right. =$ 2.76E-03 lb/hr

[4] Controlled RTO 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) = $\frac{2.76\text{E-}03\ \text{lb}}{\text{hr}} \left| \frac{8{,}760\ \text{hr}}{\text{yr}} \right| \frac{1\ \text{ton}}{2{,}000\ \text{lb}} =$ 1.21E-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 CO2 (lb/hr) = Inlet to RTO (lb/hr) x DRE (%)/100 x Carbon Count (#)

Example Converted Methane Hourly Emission Rate (lb/hr) = $\frac{0.14\ \text{lb}}{\text{hr}} \left| \frac{98\%}{100} \right| 1 =$ 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) = $\frac{0.14\ \text{lb}}{\text{hr}} \left| \frac{8{,}760\ \text{hr}}{\text{yr}} \right| \frac{1\ \text{ton}}{2{,}000\ \text{lb}} =$ 0.59 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) = $\frac{2686.29\ \text{lb}}{\text{hr}} \left| 1 \right. + \frac{1.82\text{E-}02\ \text{lb}}{\text{hr}} \left| 21 \right. + \frac{0.01\ \text{lb}}{\text{hr}} \left| 310 \right. =$ 2688.70 lb/hr

Targa Midstream Services LLC - Mont Belvieu Plant
Amine Still Vent Emissions During Scheduled RTO Downtime
GHG Emissions - Uncontrolled Amine Acid Gas Still Vent Emissions During Scheduled RTO Downtime

Input Data		
Maximum Amine Acid Gas Flowrate =	2,571.91	lb/hr
	0.02	MMscf/day
Maximum Amine Flash Gas Flowrate =	79.10	lb/hr
	0.01	MMscf/day
Hours of Operation =	24	hrs/yr

[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.

Speciated GHG Emissions

Gas Stream	Compound	Uncontrolled GHG Emissions[1] (lb/hr)	(tpy)
Acid Gas	Carbon Dioxide	2,482.41	29.79
	Methane	0.14	1.66E-03
Flash Gas	Carbon Dioxide	0.17	1.98E-03
	Methane	0.77	0.01

	Total GHG Emissions[2] (lb/hr)	(tpy)
CO_2	2,482.57	29.79
CH_4	0.91	0.01
CO_2e	2,501.66	30.02

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

Example Controlled Methane Annual Emission Rate (tpy) = $\frac{0.14\text{ lb}}{\text{hr}} \times \frac{24\text{ hr}}{\text{yr}} \times \frac{1\text{ ton}}{2{,}000\text{ lb}}$ = 1.66E-03 tpy

[2] CO_2e Hourly Emission Rate (lb/hr) = CO_2 Emission Rate (lb/hr) x CO_2 GWP + CH4 Emission Rate (lb/hr) x CO2 GWP

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{2{,}483\text{ lb}}{\text{hr}} \times 1 + \frac{9.09\text{E-01 lb}}{\text{hr}} \times 21$ = 2,502 lb/hr

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

TCEQ

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
TEG-2	FLR-5, TEG-2	Flare - Normal Operation	CO_2e	3,607.87	4,875.21
			CO_2	3,586.79	4,866.27
			CH_4	0.93	0.09
			N_2O	<0.01	0.02
RTO-5	RTO-5	RTO-5 Regenerative Thermal Oxidizer	CO_2e	2,688.70	11,776.52
			CO_2	2,686.29	11,765.94
			CH_4	0.02	0.08
			N_2O	6.56E-03	0.03
RTO5-MSS	RTO5-MSS	RTO Startup Emissions	CO_2e	234.01	2.81
			CO_2	233.78	2.81
			CH_4	4.40E-03	5.28E-05
			N_2O	4.40E-04	5.28E-06
AU-4	AU-4	Amine Still Vent During RTO Downtime	CO_2e	2,501.66	30.02
			CO_2	2,482.57	29.79
			CH_4	0.91	1.66E-03
			N_2O	--	-
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:	October 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)
TEG-2	FLR-5, TEG-2	Flare - Normal Operation	15	316335	3301920	185	1.79231855	65.6168	1831.73			
RTO-5	RTO-5	RTO-5 Regenerative Thermal Oxidizer	15	316335	3301920	30	1.83333333	31.5679	350			
RTO5-MSS	RTO5-MSS	RTO Startup Emissions	15	316335	3301920	30	1.83333333	31.5679	350			
AU-4	AU-4	Amine Still Vent During RTO Downtime	15	316335	3301920	75	1	80.3	120			
F5A	F5A	Hot Oil Heater	15	316371	3302016	122	4.12454786	61.85	410			
F5B	F5B	Hot Oil Heater	15	316382	3302018	122	4.12454786	61.85	410			
FUG-FRAC5	FUG-FRAC5	Frac5 Fugitives	15	316339	3301923	10				464.1	326.8	345
FLR-5	Maintenance	Controlled Maintenance Emissions	15	316339	3301923	185	1.79231855	65.6168	1831.73			
FLR-5	Startup	Controlled Startup Emissions	15	316438	3302033	185	1.79231855	65.6168	1831.73			
FLR-5	Shutdown	Controlled Shutdown Emissions	15	316450	3302035	185	1.79231855	65.6168	1831.73			
Shutdown	Shutdown	Shutdown Emissions to Atmosphere	15	316476	3302039	10				464.1	326.8	345
Maintenance	Maintenance	Maintenance Emissions to Atmosphere	15	316463	3302037	10				464.1	326.8	345

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

FIN/EPN	Description	Proposed BACT Limit
F5A	Hot Oil Heater	8.11 lb CO_2/ bbl
F5B	Hot Oil Heater	
AU-4/ RTO-5	Amine Unit	Work Practices
TEG-2/ FLR-5	TEG Dehydration Unit	Work Practices
FLR-5	Pilot Gas and Supplemental Fuel Combustion, Amine Unit, TEG Dehydrator, and MSS activities	Work Practices
FUG-FRAC5	Fugitive Emissions	Work Practices
EPN Shutdown, EPN Maintenance	Maintenance and Shutdown Emissions	Work Practices

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.[38] 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

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

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 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 regenerative thermal oxidizer 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;
- Low Carbon Fuel Selection;
- Fuel Gas Pre-heater/Air Pre-heater;
- Good Combustion Practices, Operating, and Maintenance Practices;
- Oxygen Trim Controls;
- Heat Integration; and
- Efficient Heater Design.

11.2.1.1. Carbon Capture and Sequestration

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.[39] 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.[40] In addition, the compression of the CO_2 would require additional power demand, resulting in additional fuel consumption (and CO_2 emissions).[41]

11.2.1.2. Low Carbon 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. Fuel Gas Pre-heater / Air Pre-heater

Preheating the fuel gas and air reduces heating load and increases thermal efficiency of the combustion unit. An air pre-heater recovers heat in the heater exhaust gas to preheat combustion air. Preheating the combustion air in this way reduces heater heating load, increases its thermal efficiency, and reduces emissions.

11.2.1.4. 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.

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

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

[41] 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

11.2.1.5. 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. [42]

11.2.1.6. 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.

11.2.1.7. 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 and fuel gas/air preheating are 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.[43] 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.

11.2.2.2. Oxygen Trim Controls

Oxygen trim controls can be used on forced draft heaters that monitor stack oxygen concentration and automatically adjust the inlet air at the burner for optimum efficiency. Targa is proposing induced draft heaters that do not have any sort of automatic control of the air flow into the burners; therefore oxygen trim controls are not technically feasible on these types of heaters.

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

[43] 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.

11.2.2.3. Fuel Gas Pre-heater / Air Pre-heater

Fuel gas/air preheating is not feasible for small heaters. This is more suitable for large boilers (>100 MMBtu/hr). In addition, these options may increase NO_X emissions.

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

With elimination of CCS, oxygen trim controls and fuel gas/air pre-heaters as a control options, the following remain as technically feasible control options for minimizing GHG emissions from the hot oil heaters:

Rank	Control Technology	Estimated Reduction	Reduction Details	Reference
1	Low Carbon Fuel Selection	28% (Natural Gas Versus No. 2 Fuel Oil)	Reduction in all GHGs.	40 CFR Part 98 Subpart C, Table C-1
2	Heat Integration	10-15%	Reduction in all GHGs.	Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry issued by EPA October 2010 Section 3.0 Summary of GHG Reduction Measures Table 1 Summary of GHG Reduction Measures for the Petroleum Refinery Industry
3	Efficient Heater Design	10%	Reduction in all GHGs.	Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry issued by EPA October 2010 Section 3.0 Summary of GHG Reduction Measures Table 1 Summary of GHG Reduction Measures for the Petroleum Refinery Industry
4	Good Combustion, Operating, and Maintenance Practices	1% - 10%	Reduction in all GHGs.	Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry issued by EPA October 2010 Section 5.1.1.5 Improved Maintenance

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:

> low carbon fuel selection;
> good combustion, operating, and maintenance practices;
> heat integration; and
> efficient heater design.

Targa proposes the 8.11 lb CO_2/bbl emission limits for the heaters:

> Hot Oil Heater (EPN F5A): 4.06lbs CO_2/bbl
> Hot Oil Heater (EPN F5B): 4.06 lbs CO_2/bbl

These proposed emission limits are based on the plant design inlet flowrate of 100,000 bbl/day.

Compliance with these emission limits will be demonstrated by monitoring plant inlet volume and performing calculations consistent with the calculations included in Section 7 of this application.

11.3. AMINE UNIT AND TEG DEHYDRATOR

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. Because the amine unit is designed to remove CO_2 from the fractionated gas stream, the generation of CO_2 is inherent to the process, and a reduction of the CO_2 emissions by process changes would reduce the process efficiency. This would result in more CO_2 in the ethane and natural gas liquids that would eventually be emitted. The TEG dehydration unit will be used to remove water or water vapor present in the ethane gas stream.

11.3.1. Step 1 – Identify All Available Control Technologies

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

> Carbon Capture and Sequestration;
> Flare;
> Thermal Oxidizer;
> Condenser;
> Proper Design and Operations; and
> Use of Tank Flash Gas Recovery System.

11.3.1.1. Carbon Capture and Sequestration

Targa conducted research and analysis to determine the technical feasibility of CO_2 capture and transfer. Since most of the CO_2 emissions 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. Flare

One option to reduce the GHGs emitted from the Mont Belvieu Plant is to send stripped amine acid gases and dehydrator waste gases to a flare. The flare is an example of a control device in which the control of certain pollutants causes the formation of collateral GHG emissions. Controlling the amine and dehydrator vent streams with a flare would also require supplemental fuel to increase the heating value of the gas to the point that it can be effectively combusted in a flare at 300 Btu/ft^3. This has collateral CO_2 and CH_4 emissions from the additional combustion of the fuel gas.. However, given the relative GWPs of CO_2 and CH_4 and the destruction of VOCs and HAPs, it is appropriate to apply combustion controls to CH_4 emissions even though it will form additional CO_2 emissions. In general, flares have a destruction efficiency rate (DRE) of 98%, resulting in minor CH_4 emissions from the process flare due to incomplete combustion of CH_4. Additionally, the flare requires the use of a continuous pilot ignition system or equivalent that results in additional GHG emissions.

11.3.1.3. Thermal Oxidizer

Another option to reduce the GHGs emitted from the Mont Belvieu Plant is to send stripped amine acid gases and dehydrator waste gases to a thermal oxidizer (TO). The TO is an example of a control device in which the control of certain pollutants causes the formation of collateral GHG emissions, the control of CH_4 in the process gas at the TO results in the creation of additional CO_2 emissions via the combustion reaction mechanism. However, given the relative GWPs of CO_2 and CH_4 and the destruction of VOCs and HAPs, it is appropriate to apply combustion controls to CH_4 emissions even though it will form additional CO_2 emissions. A regenerative thermal oxidizer (RTO) has a high efficiency heat recovery. This allows the facility to recover heat from the exhaust stream, reducing the overall heat input of the plant. In general, TOs have a destruction efficiency rate (DRE) greater than of 99%, resulting in minor CH_4 emissions from the process flare due to incomplete combustion of CH_4. In contrast with a flare, which requires the use of additional fuel to maintain a constant pilot, a RTO only uses additional natural gas to get up to the optimum temperature for combustion resulting in lower use of assist gas and lower GHG emissions due to pilot burning when compared to a flare.

11.3.1.4. Condenser

Condensers provide supplemental emissions control by reducing the temperature of the still column vent vapors on amine and TEG dehydration units to condense water and VOCs, including CH_4. The condensed liquids are then collected for further treatment or disposal. The reduction efficiency of the condensers is variable and depends on the type of condenser and the composition of the waste gas, ranging from 50-98% of the CH_4 emissions in the waste gas stream.

11.3.1.5. Proper Design and Operations

The amine unit and the TEG dehydration unit will be new equipment installed on site. New equipment has better energy efficiency, hence reducing the GHGs emitted during combustion. The new equipment will operate at a minimum circulation rate with consistent amine concentrations. By minimizing the circulation rate, the equipment avoids pulling out additional VOCs and GHGs in both amine and glycol streams, which would increase VOC and GHG emissions into the atmosphere.

11.3.1.6. Use of Tank Flash Gas Recovery Systems

The amine unit and TEG dehydration unit will be equipped with flash tanks. The flash tanks will be used to recycle off-gases formed as the pressure of the rich glycol/rich amine streams drops to remove lighter compounds in the stream prior to entering the reboiler. These off-gases are recycled back into the plant for reprocessing, instead of venting to the atmosphere or combustion device. The use of flash tanks increases the effectiveness of other downstream control devices.

11.3.2. Step 2 – Eliminate Technically Infeasible Options

All control options identified in Step 1 are technically feasible.

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

The control options for minimizing GHG emissions from the amine unit and TEG dehydration unit are ranked below:

Rank	Control Technology	Estimated CO_2e Reduction	Reduction Details	Reference
1	Carbon Capture and Sequestration	80%	Reduction of all GHGs.	Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry issued by EPA October 2010 Section 5.1.4 Carbon Capture.

Rank	Control Technology	Estimated CO_2e Reduction	Reduction Details	Reference
				(Also noted that industrial application of this technology is not expected to be available for 10 years.)
2	Proper Design and Operation	1% - 10%	Reduction of all GHGs.	Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry issued by EPA October 2010 Section 5.1.1.5 Improved Maintenance
3	Condenser	< 0.25%	Reduction of CH_4 in acid gas and dehydrator waste gas.	Vendor Data
4	Use of Tank Flash Gas Recovery Systems	< 0.25%	Reduction of CH_4 in flash gas only.	Hard piped back into the system
5	Thermal Oxidizer	--	Reduction in acid gas CH_4. Increase in CO_2 due to acid gas combustion	Vendor Data
6	Flare	--	Reduction in acid gas CH_4. Increase in CO_2 due to acid gas, supplemental fuel, and pilot gas combustion.	http://www.tceq.texas.gov/permitting/air/guidance/newsourcereview/flares/ and vendor data

11.3.4. Step 4 – Evaluate Most Effective Control Options

The only options that are technical feasibility, but could have a significant adverse energy or environmental impacts (that would influence the GHG BACT selection process) are the use of CCS as discussed below. All other control technologies listed in Step 1 are considered technically feasible. No significant adverse energy or environmental impacts (that would influence the GHG BACT selection process) associated with the above-mentioned technically feasible control options are expected

11.3.4.1. Carbon Capture and Sequestration

While the amine acid gas stream routed to the RTO 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).[44] This website provides the details of registered wells and permitted fluids for injection. Most of the wells are permitted to inject saltwater, 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.

Targa has provided a comparison of the currently estimated cost (only installation of the pipeline) to the current project's annualized cost. A copy of this cost analysis is provided at the end of this section. If this is not sufficient to demonstrate that the project is not economically feasible, Targa will then provide the additional cost estimates for installing equipment at the site to get the amine and glycol vents into the pipeline. The additional equipment that would be needed to be installed at the plant to compress the amine vent stream into a pipeline at approximately 1200 psig would include the following:

- Approximately 2,400 hp electric motor
- 6-throw compressor frame with 5 stages of compression
- 5 bay fin fan cooling unit
- MCC building for electrical switchgear, VFD and motor starters
- Suction scrubbers on each compressor stage plus final scrubber (6 total)
- Measurement, meter run and sampling equipment
- Approximately 1.5-2.0 MMBtu/hr glycol unit, contactor, regeneration unit with VRU to dehydrate the CO_2 stream prior to pipeline
- Controls/Instrumentation, panel board, PLC
- Foundations for compressor/motor, MCC building, glycol unit, cooling unit, etc.
- Power to MCC building

Therefore, based on the comparison between the pipeline transfer cost and the project's annualized cost, although technically feasible, off-site transfer is not regarded as a viable or economically feasible CO_2 control option. Additionally, CO_2 capture and transfer would have negative environmental and energy impacts, as discussed above.

11.3.5. Step 5 – Select BACT for the Amine Unit/TEG Dehydration Unit

Targa proposes the following design elements as BACT for the amine unit and TEG dehydration unit. Work practices are discussed in the flare section in place of a numerical BACT limit:

- Thermal Oxidizer for amine unit still vent (EPN AU-4)
- Flare for TEG dehydrator still vent (EPN TEG-2);
- Proper Design and Operation;
- Use of Tank Flash Gas Recovery Systems; and
- Use of a Condenser.

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

11.4. REGENERATIVE THERMAL OXIDIZER

The RTO (EPN RTO-5) at the Mont Belvieu Plant will be used to destroy the process waste gas produced by the amine unit. GHG emissions will be generated by the combustion of natural gas as well as combustion of the vent gas to the RTO.

CO_2 emissions from burning process gas are produced from the combustion of carbon-containing compounds (e.g., VOCs, CH_4) present in the vent streams routed to the RTO and the burner fuel. CO_2 emissions from the RTO are based on the estimated amount of carbon-containing gases produced from the amine. In addition, minor CH_4 emissions from the RTO are emitted from the RTO due to incomplete combustion of CH_4.

The RTO is an example of a control device in which the control of certain pollutants causes the formation of collateral GHG emissions. Specifically, the control of CH_4 in the process gas at the RTO results in the creation of additional CO_2 emissions via the combustion reaction mechanism. However, given the relative GWPs of CO_2 and CH_4 and the destruction of VOCs and HAPs, it is appropriate to apply combustion controls to CH_4 emissions even though it will form additional CO_2 emissions.[45]

The following sections present a BACT evaluation for GHG emissions from combustion of burner gas and vent gas released to the RTO from the amine unit.

11.4.1. Step 1 – Identify All Available Control Technologies

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

> Carbon Capture and Sequestration;
> Proper Design;
> Low Carbon Fuel Selection; and
> Good Combustion, Operating, and Maintenance Practices.

11.4.1.1. Carbon Capture and Sequestration

A detailed discussion of CCS technology is provided in Section 11.3. The emission units evaluated in this step for the RTO are the burners on the RTO. The employment of CCS for the emissions from process units that vent through the RTO were deemed economically infeasible as discussed in Section 11.3.4. Therefore controlling these minimal emissions generated from the RTO burners are also economically infeasible.

11.4.1.2. Proper Design

Good RTO design can be employed to destroy any VOCs and CH_4 entrained in the waste gas from the amine unit. Good RTO design includes flow measurement and monitoring/control of waste gas heating values.

11.4.1.3. Low Carbon Fuel Selection

The fuel for firing the proposed RTO will be limited to natural gas fuel. Natural gas has the lowest carbon intensity of any available fuel for the RTO. In addition, the RTO will utilize the gas-fired burner system to bring the RTO up to

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[45] For example, combusting 1 lb of CH_4 (21 lb CO_2e) at the flare will result in 0.02 lb CH_4 and 2.7 lb CO_2 (0.02 lb CH_4 x 21 CO_2e/CH_4 + 2.7 lb CO_2 x 1 CO_2e/CO_2 = 2.9 lb CO_2e), and therefore, on a CO_2e emissions basis, combustion control of CH_4 is preferable to venting the CH_4 uncontrolled.

combustion temperature during startup only. After the system has reached temperature, the burners will be shut off and the system will function using the energy content of the amine waste streams alone to support combustion.

11.4.1.4. Good Combustion, Operating, and Maintenance Practices

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

11.4.2. Step 2 – Eliminate Technically Infeasible Options

As discussed above, the burners are the unit of interest in this section; therefore, the use of CCS is technically infeasible as illustrated in Section 11.2.2.1.

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

The control options for minimizing GHG emissions from the RTO are ranked below:

Rank	Control Technology	Estimated Reduction	Reduction Details	Reference
1	Low Carbon Fuel Selection	28% (Natural Gas Versus No. 2 Fuel Oil)	Reduction in all GHGs.	40 CFR Part 98 Subpart C, Table C-1
2	Proper Design	1% - 10%	Reduction in all GHGs.	Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry issued by EPA October 2010 Section 5.1.1.5 Improved Maintenance
3	Good Combustion, Operating, and Maintenance Practices	1% - 10%	Reduction in all GHGs.	EPA Guidance document "Good Combustion Practices" available at: http://www.epa.gov/ttn/atw/iccr/dirss/gcp.pdf.

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 the RTO

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

- Proper Design;
- Low Carbon Fuel Selection; and
- Good combustion, Operating, and Maintenance Practices.

Compliance with work practices is noted below:

- The Thermal Oxidizer is designed to combust VOC and methane in the waste gas from the amine vent streams.
- For burner combustion, the natural gas fuel usage will be recorded using a flow meter.

- Waste gas will be sampled and analyzed on a quarterly basis for composition.
- The flowrate of the waste gas combusted will be measured and recorded using a flow meter.
- Periodic maintenance will be performed at least annually on the TO.
- Targa will install a temperature monitor in the combustion chamber to record the combustion temperature. Targa would like to base the minimum combustion temperature to be determined during the initial stack test. Targa will maintain that temperature at all times when processing waste gases from the amine and dehydration units in the thermal oxidizer to ensure proper destruction efficiency. Targa will install and maintain a temperature recording device with an accuracy of ± 0.75 percent of the temperature being measured expressed in degrees Celsius.
- Targa requests the continuous temperature monitor to be based on a minimum of 1 reading per 15 minutes, reduced to hourly temperature averages.

11.5. FLARE

Stripped dehydrator waste gases will be routed to a flare. GHG emissions from the flare result from routing removed CO_2 from the dehydrator to the flare and the combustion of process waste gases from 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 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.

The flare is an example of a control device in which the control of certain pollutants causes the formation of collateral GHG emissions. Specifically, the control of CH_4 in the process gas at the flare results in the creation of additional CO_2 emissions via the combustion reaction mechanism. However, given the relative GWPs of CO_2 and CH_4 and the destruction of VOCs, it is appropriate to apply combustion controls to CH_4 emissions even though it will form additional CO_2 emissions.[46]

The flare at the Mont Belvieu Plant will also be used to destroy the off-gas produced during emergency situations and during planned MSS activities. GHG emissions will be generated by the combustion of natural gas as well as combustion of the vent gas to the flare.

CO_2 emissions from flaring process gas are produced from the combustion of carbon-containing compounds (e.g., VOCs, CH_4) present in the vent streams routed to the flare during MSS events and the pilot fuel. CO_2 emissions from the flare are based on the estimated flared carbon-containing gases derived from heat and material balance data. In addition, minor CH_4 emissions from the flare are emitted from the flare due to incomplete combustion of CH_4.

The following sections present a BACT evaluation for GHG emissions from combustion of burner gas and vent gas released to the flare from the amine unit and TEG dehydration unit.

11.5.1. Step 1 – Identify All Available Control Technologies

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

- Carbon Capture and Sequestration

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

11.5.1.1. Carbon Capture and Sequestration

A detailed discussion of CCS technology is provided in Section 11.3. The emission unit evaluated in this step for the flare is the pilot for the flare. The employment of CCS for the emissions from process units that vent through the Flare were deemed economically infeasible as discussed in Section 11.3.4. Therefore controlling these minimal emissions generated from the flare pilot is also economically infeasible.

11.5.1.2. 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.

11.5.1.3. 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.

11.5.1.4. 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.

11.5.1.5. 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.

11.5.1.6. 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.

11.5.2. 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.

11.5.2.1. Carbon Capture and Sequestration

With no ability to collect exhaust gas from a flare other than using an enclosure, post combustion capture is technically infeasible and not an available control option. Also, as discussed above in Section 11.4.1.1, CCS for the pilot flare is economically infeasible.

11.5.2.2. 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 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.

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

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

Rank	Control Technology	Estimated Reduction	Reduction Details	Reference
1	Low Carbon Fuel Selection	18.6% (Natural Gas Versus Butane)	Reduction in all GHGs.	40 CFR Part 98 Subpart C, Table C-1
2	Good Flare Design	1% - 15%	Reduction in all GHGs.	Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry issued by EPA October 2010 Section 3.0 Summary of GHG Reduction Measures Table 1 Summary of GHG Reduction Measures for the Petroleum Refinery Industry
3	Good Combustion, Operating, Maintenance Practices	1% - 10%	Reduction in all GHGs.	EPA Guidance document "Good Combustion Practices" available at: http://www.epa.gov/ttn/atw/iccr/dirss/gcp.pdf.
4	Limited Vent Gas Releases to Flare	N/A	Reduction in all GHGs.	N/A

11.5.4. Step 4 – Evaluate Most Effective Control Options

No significant adverse energy or environmental impacts (that would influence the GHG BACT selection process) associated with the above-mentioned technically feasible control options are expected.

11.5.5. Step 5 – Select BACT for the Flare

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

- Low carbon fuel selection;
- Good combustion, operating, and maintenance practices;
- Good flare design; and
- 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.

Compliance with work practices is noted below:

- Flare shall have a minimum destruction and removal efficiency (DRE) of 99% for compounds with three carbons or less and 98% for all other compounds based on flowrate and gas composition measurements as specified in 40 CFR Part 98 Subpart W §98.233(n).
- The flare shall be designed and operated in accordance with 40 CFR 60.18 including specifications of minimum heating value of the waste gas, maximum tip velocity, and pilot flame monitoring.
- An infrared monitor is considered equivalent to a thermocouple for flame monitoring purposes.
- Targa proposes to limit MSS activities and flaring events to minimize GHG emissions from this source
- Targa proposes the implementation of good combustion practices noted in their initial application.
- Waste gas will be collected with a composite sampler and analyzed monthly to determine composition of gas to the flare.

11.6. 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.

11.6.1. 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 Leak Detection and Repair (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.

11.6.1.1. 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.

11.6.1.2. Air-Driven Pneumatic Controllers

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

11.6.1.3. 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.

11.6.1.4. 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.

11.6.1.5. 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.

11.6.1.6. 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.

11.6.2. 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.

11.6.3. Step 3 - Rank Remaining Control Technologies by Control Effectiveness

11.6.3.1. Air-Driven Pneumatic Controllers

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

11.6.3.2. 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). [47] The following table demonstrated the control efficiencies for TCEQ's various LDAR Programs:

Equipment/Service	**28M**	**28RCT**	**28VHP**	**28MID**	**28LAER**	**AVO**
Valves						
Gas/Vapor	75%	97%	97%	97%	97%	97%
Light Liquid	75%	97%	97%	97%	97%	97%
Heavy Liquid	0%	0%	0%	0%	0%	97%
Pumps						
Light Liquid	75%	75%	85%	93%	93%	93%
Heavy Liquid	0%	0%	0%	0%	0%	93%
Flanges/Connectors						
Gas/Vapor	30%	30%	30%	30%	97%	97%
Light Liquid	30%	30%	30%	30%	97%	97%
Heavy Liquid	30%	30%	30%	30%	30%	97%
Compressors	75%	75%	85%	95%	95%	95%
Relief Valves (Gas/Vapor)	75%	97%	97%	97%	97%	97%
Open-ended Lines	75%	97%	97%	97%	97%	97%
Sampling Connections	75%	97%	97%	97%	97%	97%

11.6.3.3. 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 (i.e. 40 CFR Part 98 Subpart W) 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.

11.6.3.4. 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.

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

11.6.3.5. High Quality Components

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

11.6.4. Step 4 - Evaluate Most Effective Control Options

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

11.6.5. 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 implemented through TCEQ's 28 LAER 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, which is a requirement per TCEQ's 28LAER program. 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.

The product pumps containing VOCs, and potentially CH_4 and CO_2, will have tandem seals equipped with detection or alarm points to eliminate seal leakage and alert personnel when the first seal begins to leak.

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.