TARGA

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August 9, 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 Gas Processing LLC
Longhorn Gas Plant

Dear Ms. Wilson:

Please find Targa Gas Processing LLC's (Targa's) response to your letter dated May 4, 2012, regarding additional information requested to our permit application for our proposed Longhorn Gas Plant. Below please find the questions followed by Targa's written response.

General

1. *There is no recommended monitoring, recordkeeping, and reporting for the CO_2 emissions. Does Targa have a preferred monitoring method for the glycol reboiler, regeneration heater, hot oil heater, regenerative thermal oxidizer, and flare?*

   Targa intends to install a separate fuel flow meter for each of the following combustion sources: hot oil heater (EPN 4), glycol reboiler (EPN 1), regeneration heater (EPN 3), regenerative thermal oxidizer (EPN 5), and flare (EPN 6). Additional monitoring is listed out in question 6 below for these emission sources.

2. *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 and 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).

3. *What is the heat input rating for the three natural gas heaters (EPNs 1, 3, 4)?*

   The heat input ratings for the heaters are provided below as well as in the emission rate calculations spreadsheets included in Section 7 of the application.

   - TEG Reboiler (EPN 1): 2.0 MMBtu/hr
   - Regeneration Heater (EPN 3): 12.4 MMBtu/hr
   - Hot Oil Heater (EPN 4): 98.0 MMBtu/hr

4. *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 submitted a Biological Assessment (BA) on May 10, 2012. This assessment included 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 still being evaluated and will be submitted to the Texas Commission on Environmental Quality (TCEQ) upon request, which has not occurred at this time.

Emission Calculations

5. *The emission calculations for the RTO and Flare, pages 16-18 in the permit application and the attached emissions data calculations, do not utilize the 40 CFR Part 98 Subpart W equations. Please provide justification and explanation for use of the provided emission calculations or provide a supplement to your application using equations W-33, W-34, W-39A, or W-39B for GHG volumetric emissions; W-36 for GHG mass emissions for the RTO of CO2 and CH4; and use equation W-40 for calculating the N2O mass emissions from the RTO. For the flare, please use equations, W-19, W-20, W-21, and W-40.*

According to 40 CFR Part 98.233(z)(1) (Subpart W), if the fuel combusted in the stationary or portable equipment is listed in Table C-1 of Subpart C, then emissions are calculated per Subpart C. Therefore Subpart C is used to calculation GHG emissions from the following sources and operating scenarios, which combust natural gas.

- RTO Startup
- Flare Pilot

- Flare Emissions from Residue and Refrigerant Compressor Blowdowns
- Flare Emissions from Pigging

Per 40 CFR Part 98.233(z)(2)(iii) (Subpart W), for combustion units that combust process vent gas, equation W-39A and W-39B are used to estimate the GHG emissions from additional carbon compounds in the waste gas. According to 40 CFR Part 98.233(z)(2)(vi) (Subpart W), for combustion units that combust process vent gas, equation W-40 is used to estimate the GHG emissions. Therefore Subpart W is used for the following sources, which combust process vent gas.

- RTO Emissions from Amine Acid Gas Combustion
- RTO Emissions from Dehydrator Waste Gas Combustion

BACT Analysis

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 provide 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.*

Targa has revised the BACT write-up in Section 10 of the application to include output based BACT limits where feasible. Please see the revised pages of Section 10 in addition to the details included below.

Heaters (EPNs 1, 3, and 4)

Targa has calculated BACT limits for GHG emission units to include the efficiency of the unit based on the plant natural gas throughput capacity. The Longhorn Gas Plant is designed to process 200 million standard cubic feet per day (MMscfd) of inlet gas. The production rate of pipeline quality natural gas is 155 MMSCFD during ethane recovery and 177 MMSCFD during ethane rejection. The updated limit below illustrates the calculation methodology and the efficiency of the heaters in terms of the plant production rate (lb/MMscf):

$$\left(233.78\frac{lb}{hr}+1{,}449.44\frac{lb}{hr}+11{,}455.22\frac{lb}{hr}\right)\div 177\frac{MMscf}{day}\times 24\frac{hr}{day}=1{,}781.5\frac{lb}{MMscf}$$

The heater duty required for the amine treater regeneration is dependent on the inlet gas composition of H_2S and CO_2. Since the gas entering the Longhorn Gas Plant will have a high CO_2 inlet concentration (and little to no H_2S) it will need a larger hot oil heater for regeneration than a similar sized plant with less CO_2 in the inlet gas. Also, the amount of natural gas liquids to natural gas (methane) in the inlet gas will also affect the size of the heaters needed and design of the plant.

Thermal Oxidizer (EPNs 5, 2, and 15)

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 CO_2 that comes directly from the amine vent stream and are not reduced by the TO. The amine unit removes CO_2 for to prevent freezing during the cryogenic expansion process and to meet pipeline specifications for transportation of the natural gas and natural gas liquid (NGL) product streams. Because the amine unit is designed to remove CO_2 from the inlet 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 natural gas and natural gas liquids that would eventually be emitted. Since a BACT limit is not feasible, Targa proposes the following operating work practices for the TO:

- The TO is designed to combust VOC and methane in the waste gas from the amine and TEG dehydrator 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.

<u>Flare (EPN 6)</u>
A short term emission limit for BACT is not feasible for this source because it is an intermittent source that is operated to control upsets and scheduled maintenance, startup, and shutdown (MSS) emissions; therefore 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.
- 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.

Fugitives (EPNs 15, 16, 17, 18, 21, FUG-1, and FUG-2)

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 air driven pneumatic devices 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. A cost analysis, Appendix E of the permit application, is provided for the amine unit and dehydrator units. Please provide a cost analysis for the equipment needed to implement CCS for the amine and dehydrator units. Also, we are requesting a comparison of the cost of CCS to the current project's annualized cost.*

Targa has provided a comparison of the currently estimated cost (only installation of the pipeline) to the current project's annualized cost. 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 CO2 stream prior to pipeline
- Controls/Instrumentation, panel board, PLC
- Foundations for compressor/motor, MCC building, glycol unit, cooling unit, etc.
- Power to MCC building

8. *The current BACT analysis does not appear to provide adequate information in the five-step BACT analysis for the three natural gas heaters, amine treating unit, TEG dehydrator, regenerative thermal oxidizer, and flare. Step 2 does not provide detailed information on the energy efficiency measures. In Step 3, the applicant should provide information on control efficiency, expected emission rate, and expected emission reductions. The applicant should provide comparative benchmark information indicating*

other similar industry operating or designed units and compare the design efficiency of this process to other similar or alike processes. The applicant should then use this information to rank the available control technologies. A comparison of equipment energy efficiencies is necessary to evaluate the energy efficiency of the proposed equipment and possible control technologies. This information should also detail the basis for your BACT proposal 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 pages of Section 10.

9. *The BACT analysis, page 37 of the permit application, for the Amine Unit and TEG Dehydrator/Regenerative Thermal Oxidizer (RTO) shows that the RTO will fire natural gas during start-up and once the system has reached temperature, the burners will be turned off. What temperature will the RTO operate at? Will natural gas not be needed to supplement the waste gases to attain the proper Btu content to achieve the proper temperature for destruction of carbon compounds? Also, confirm the destruction and removal efficiency of the RTO. The BACT analysis, on page 38 of the permit application, states that the more expensive RTO was chosen over a standard oxidizer to reduce fuel consumption and emission rates, giving a difference in efficiency from 65% to 98%. Please provide your preferred method to monitor this efficiency for compliance.*

   The RTO is intended to operate at approximately 1500 °F. The RTO is designed with a thermal heat exchanger efficiency of 95% and can self-sustain the normal operating temperature with a waste gas heat input as low as 8-10 Btu/scf. This makes an RTO ideal for the treatment of amine acid gas processes that have a low VOC and btu/scf content. Supplemental natural gas will not be needed for proper temperature in the thermal oxidizer. Therefore, using a RTO, the burner will typically not operate during normal operation and thus have a better thermal efficiency over a recuperative thermal oxidizer. By comparison, traditional thermal recuperative oxidizers using a shell and tube heat exchanger typically average 65% design thermal efficiency. In the original application, Targa was attempting to demonstrate that choosing a regenerative over a recuperative thermal oxidizer was a more thermally efficient design.

   The RTO will achieve a destruction efficiency of 99% for methane or less than 10 ppmv methane at the outlet.

10. *The BACT analyses for fugitive emissions, on pages 42 though 45 of the permit application, indicated that the TCEQ 28VHP, LDAR program will be used, and states*

> *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.

In addition to the above changes we have made to the application for clarification, Targa is submitting two additional changes to the permit application and emission rate calculations. First, Targa is adding purge gas on the flare, which is recommended by the manufacturer. A flare manufacturer had not been established when the original application was submitted. Secondly, the amine treater vent stream emission rates were not maximized to worst-case scenarios. Targa is revising the application to show increased CO_2 emission rates from the amine treater. While the design parameters of the amine treater are not changing, the inlet gas composition is changing.

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 Gas Processing LLC

Attachments

cc: Clark White, Targa, Vice President (via email)
Shane Tribe, Targa – North Texas, Environmental Specialist (via email)
Kim Peterson, Targa, Senior Director Engineering (via email)
Environmental Files

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ATTACHMENT 1

Permit Application Revised Section 10

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

10.4. GHG BACT EVALUATION FOR PROPOSED EMISSION SOURCES

The following is an analysis of BACT for the control of GHG emissions from the proposed Longhorn Gas Plant 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 included at the end of this section.

Table 10.4-1 provides a summary of the proposed BACT limits discussed in the following sections.

Table 10.4-1. Proposed GHG BACT Limits for Longhorn Gas Plant

EPN	Description	Proposed BACT Limit
1	TEG-1 Glycol Reboiler	1,783.23 CO_2 lb/MMscf (combined limit for the 3 units)
3	HTR-1 Regen Heater	
4	HTR-2 Hot Oil Heater	
5	RTO-1 Regen Thermal Oxidizer	Work Practices
6	Flare-1 Flare (Pilot)	Work Practices
5-MSS	RTO-1 Startup	Work Practices
15-MSS	Amine Still Vent During RTO Downtime	Work Practices
2-MSS	TEG Dehydrator During RTO Downtime	Work Practices

Detailed BACT analysis is conducted for major CO_2e contributors.

10.5. 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. As

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

[33] U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: October 2010). http://www.epa.gov/nsr/ghgdocs/iciboilers.pdf

[34] U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: October 2010). http://www.epa.gov/nsr/ghgdocs/refineries.pdf

such, overall energy efficiency was a basic design criterion in the selection of technologies and processing alternatives to be installed at the proposed Longhorn Gas Plant.

The new 200 MMscfd Longhorn Gas Processing Plant will be designed and constructed using all new, energy efficient equipment. The plant is designed for deep ethane recovery using minimal fuel and power. This is accomplished using a state of the art recovery process, incorporating multiple exchangers for maximum heat recovery and utilizing an efficient non-powered turbo- expander. This facility will utilize high pressure gas for efficient product recovery.

The facility is completely electric-driven from an existing high voltage transmission line located adjacent to the property. There will be three (3) electric-driven compressors for residue compression. The plant's refrigeration system utilizes all electric compression using screw type compressors for propane circulation. This is much more efficient with considerably less emissions potential (e.g., packing, fugitive points) than a reciprocating compressor in this service.

Many of the required electric pumps and one of the large residue compressors in the plant are controlled by Variable Frequency Drives (VFDs) that reduce electrical consumption by varying motor speed in response to control inputs. Since motors/pumps are rarely needed at maximum speed under normal operations, this lowers electrical consumption considerably. The product 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 UCARSOL AP-814 as the amine treating fluid because of its affinity for CO_2. This amine is more expensive but requires the lowest circulation rates and lowest heat duties (i.e., less fuel) to treat the inlet gas than other amine solutions.

In dehydrating, typical glycol units are sized for a water content of 7 lbs per MMcf of outlet gas. The Longhorn unit has been sized for minimal circulation and minimal heat duty. It will dehydrate just enough to allow the mole sieve beds to dehydrate effectively.

The vents from the amine unit and dehydrator will be routed to a Regenerative Thermal Oxidizer (RTO) to assure complete destruction of VOCs and hazardous components. The RTO is intended to operate at 1500ºF. The RTO is designed with a thermal heat exchanger efficiency of 95% and can self-sustain the normal operating temperature with a waste gas heat input as low as 8-10 Btu/scf. This makes an RTO ideal for the treatment of amine acid gas processes that have a low VOC and btu/scf content. Supplemental natural gas will not be needed for proper temperature in the thermal oxidizer. Therefore, using a RTO, the burner will typically not operate during normal operation and thus have a better thermal efficiency over a recuperative thermal oxidizer. By comparison, traditional thermal recuperative oxidizers using a shell and tube heat exchanger typically average 65% design thermal efficiency. The glycol vent will be condensed and recycled to the reboiler fuel to be burned. All water accumulated from the amine unit and glycol unit will be recycled back to their respective systems.

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. Inlet gas separator liquids will be re-injected back into the pipeline for handling at another facility.

The facility will have a closed drain system for collection of incidental condensate from process scrubbers and dumps. This will be equipped with a vapor recovery unit (VRU)-controlled flash tank that routes any vapors back to the plant fuel system for burning. All major skids and equipment containing ground-contaminating liquids will have concrete pads underneath extending out 3 feet from all sides to facilitate maintenance and to collect any drips or spills underneath. Compressor packages will have drip rails installed on skids to contain and collect oil drips and spills.

10.6. BENEFITS OF ELECTRIC MOTORS

Electric motors, in comparison to other driver alternatives, (1) produce no GHG emissions, (2) do not have their energy efficiency affected by weather or add-on control technologies, (3) have more efficient turndown characteristics for variable output operations, (4) can be sized to allow for a more efficient design and (5) have no waste heat which is readily usable with the design of the Longhorn Gas Plant. With respect to weather-related inefficiencies, other primary driver alternatives typically lose efficiency (i.e., become de-rated) as temperatures and humidity levels deviate from the design conditions used to engineer the applicable driver.

Selecting electric motors as the primary drivers for the large compressors and pumps at the Longhorn Gas Plant avoids these inefficiencies. In addition, other primary driver alternatives which produce GHG emissions would likely utilize add-on control technologies (such as selective catalytic reduction units) which cause additional energy inefficiencies for the driver. Once operational, the Longhorn Gas Plant will be operated at varying rates due to, among other things, changes in customer demands and variations in the inlet natural gas supply.

When coupled with variable speed drives (which will be used at the Longhorn Gas Plant), electric motors remain efficient within a larger operating envelope than other primary driver alternatives. In other words, electric motors have more efficient turndown characteristics. Furthermore, electric motors are supplied in a greater number of standard sizes which allows Targa to select a motor size that is optimal to the desired design output required by the project. If a different primary driver was selected, the size of the driver would determine the design output of the train rather than vice versa, which would lead to Targa having to design a train size which is larger than desired, thus losing energy efficiency through over-sizing of equipment. Finally, other primary driver alternatives typically generate a significant amount of heat as a by-product of their operation which, in some instances, can be utilized to increase the efficiency of those drivers (such as through the use of heat recovery steam generator units).

10.7. PROCESS 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 a hot oil heater, a mole sieve regenerator heater, and a glycol dehydrator reboiler. The following section presents BACT evaluations for GHG emissions from the proposed process heaters.

10.7.1. Step 1 – Identify All Available Control Technologies

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

- Carbon Capture and Sequestration;
- Low Carbon Fuel Selection;
- Good Combustion, Operating, and Maintenance Practices;
- Oxygen Trim Controls;
- Fuel Gas Pre-heater / Air Pre-heater; and
- Efficient Heater Design.

10.7.1.1. Carbon Capture and Sequestration

As previously discussed, this project's CO_2e emissions profile 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 process 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.[35] 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.[36] In addition, the compression of the CO_2 would require additional power demand, resulting in additional fuel consumption (and CO_2 emissions).[37]

10.7.1.2. Low Carbon Fuel Selection

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

10.7.1.3. Good Combustion, Operating, and Maintenance Practices

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

10.7.1.4. Oxygen Trim Controls

Combustion units operated with too much excess air may lead to inefficient combustion, and additional energy will be needed to heat the excess air. Oxygen monitors and intake air flow monitors can be used to optimize the fuel/air mixture. [38]

10.7.1.5. 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.

10.7.1.6. Efficient Heater Design

Efficient heater design and proper air-to-fuel ratio improve mixing of fuel and create more efficient heat transfer. Since Targa is proposing to install new heaters, these heaters will be designed to optimize combustion efficiency. Additionally, as discussed in Section 10.5, the amine treater and TEG dehydrator have been designed to minimize heat duty and require less fuel to treat inlet gas.

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

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

[37] 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

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

10.7.2. 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.

10.7.2.1. 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.[39] 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.

10.7.2.2. 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.

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

With elimination of CCS and fuel gas/air preheating as control options, the following remain as technically feasible control options for minimizing GHG emissions from the process 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	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
3	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

[39] *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.

Rank	Control Technology	Estimated Reduction	Reduction Details	Reference
4	Oxygen Trim Controls	1% - 3%	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

10.7.4. 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.

10.7.5. Step 5 – Select BACT for the Process Heaters

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

> Low Carbon Fuel Selection;
> Good Combustion, Operating, and Maintenance Practices;
> Oxygen Trim Control; and
> Efficient Heater Design.

Targa proposes the combined CO_2 emission limit for the heaters is 1,783.23 lb CO_2/MMscf. This is the sum of the individual limits for the heaters as shown below:

> TEG-2 Glycol Reboiler (EPN 1): 31.73lbs of CO_2/MMscf
> HTR-1 Regeneration Heater (EPN 3): 169.73 lbs of CO_2/MMscf
> HTR-2 Hot Oil Heater (EPN 4): 1,554.77 lbs of CO_2/MMscf

These proposed emission limits are based on the plant design outlet flowrate of 177 MMSCFD. The production rate of pipeline quality natural gas is approximately 155 MMSCFD during ethane recovery and approximately 177 MMSCFD during ethane rejection.

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.

10.8. AMINE UNIT AND TEG DEHYDRATOR

The amine unit at the Longhorn Gas Plant will be used to remove CO_2 in order to prevent freezing during the cryogenic expansion process and to meet pipeline specifications for transportation of the NGL product stream. Because the amine unit is designed to remove CO_2 from the inlet 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 natural gas and natural gas liquids that would eventually be emitted. The TEG dehydration unit will be used to remove water from the gases.

10.8.1. 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 Operation
> Use of Tank Flash Gas Recovery Systems

10.8.1.1. 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 units, Targa conducted studies to evaluate potential options to capture and transfer the CO_2 to an off-site facility for injection.

Based on the results of these studies, capture and transfer of CO_2 from the amine treatment units is technically feasible. A study was performed to evaluate the potential options for capture and transfer of CO_2 from the Longhorn Gas Plant (located near Decatur in Wise 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.

10.8.1.2. Flare

The use of a flare can only reduce the CH_4 emissions contained in the Longhorn Gas Plant stripped amine acid gases and dehydrator waste gases. 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 streams with a flare would also require significant supplemental fuel to increase the heating value of the waste gases to the point that it can be effectively combusted in a flare at 300 Btu/ft^3. This will create collateral CO_2 and CH_4 emissions from the additional combustion of the fuel gas and increase the overall CO_2e emissions from this control device. Flares have a destruction efficiency rate (DRE) of 98% for VOCs and 99% for compounds containing no more than 3 carbons and contain no elements other than carbon and hydrogen, including CH_4. Additionally, the flare requires the use of a continuous pilot ignition system or equivalent that results in additional GHG emissions from natural gas combustion in the pilot. The combustion of the supplemental fuel and pilot fuel result in an overall increase in the net CO_2e emissions from this source.

10.8.1.3. Thermal Oxidizer

Another option to reduce the CH_4 emitted from the Longhorn Gas Plant is to send stripped amine acid gases and dehydrator waste gases to a thermal oxidizer (TO). The TO is also 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) of 99% or greater. In contrast with a flare, which requires the use of supplemental fuel to increase the waste gas heating value as well as a constant pilot, a RTO only uses a minimal amount of natural gas to get up to the optimum temperature for combustion resulting in lower use of supplemental fuel and lower GHG emissions.

10.8.1.4. Condenser

Condensers are supplemental emissions control that reduces 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%. The use of condensers in amine units and TEG dehydrators, coupled with a combustion unit like the one being proposed by Targa, reduces the waste gas streams by at least 50%, resulting in reduced GHG emissions.

10.8.1.5. 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. The amine unit and the TEG dehydrator still overhead stream will be controlled with a condenser and an RTO.

10.8.1.6. 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.

10.8.2. Step 2 – Eliminate Technically Infeasible Options

All control options identified in Step 1 are technically feasible.

10.8.3. 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. *(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 5.1.5 Improved Maintenance
3	Condenser	< 0.25%	Reduction of CH_4 in acid gas and dehydrate 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

Rank	Control Technology	Estimated CO_2e Reduction	Reduction Details	Reference
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

10.8.4. Step 4 – Evaluate Most Effective Control Options

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

While the process stream from the amine unit and TEG dehydration unit are relatively high in CO_2 content, additional processing will be required to implement CCS. These include separation, 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 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 Wise County (District No. 9) and adjacent districts (District Nos. 5 and 7B).[40] 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 proposed Longhorn Gas Plant, the nearest CO_2 injection well is located at 110 miles. A map of the location of the proposed Longhorn Gas Plant and the nearest well is included in Appendix C.

As can be seen in the map, a CO_2 transfer pipeline laid straight from the Longhorn Gas Plant to this well would need to pass through the Dallas-Fort Worth (DFW) Metroplex, which is not technically, economically, or environmentally feasible. Therefore, the actual length of a transfer pipeline would be much greater than 110 miles. For cost estimation purposes, a pipeline length of 110 miles is used to be conservative.

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 D 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 in Appendix E of this application. 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

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

- 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.

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

Targa proposes the following design elements and work practices as BACT for the amine unit and TEG dehydration unit in place of a numerical BACT limit:

- Thermal Oxidizer;
- Proper Design and Operation;
- Use of Tank Flash Gas Recovery Systems; and
- Use of a Condenser.

10.9. REGENERATIVE THERMAL OXIDIZER

The RTO at the Longhorn Gas Plant will be used to destroy the process waste gas produced by the amine unit and TEG dehydration 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 and TEG dehydration unit. 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.[41]

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 and TEG dehydration unit.

[41] 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.

10.9.1. 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.

10.9.1.1. Carbon Capture and Sequestration

A detailed discussion of CCS technology is provided in Section 10.8. 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 10.8.4. Therefore controlling these minimal emissions generated from the RTO burners are also economically infeasible.

10.9.1.2. Proper Design

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

10.9.1.3. 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 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 and TEG dehydrator waste streams alone to support combustion.

10.9.1.4. 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.

10.9.2. 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 illustrate in Section 10.7.2.1.

10.9.3. 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

Rank	Control Technology	Estimated Reduction	Reduction Details	Reference
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.

10.9.4. Step 4 – Evaluate Most Effective Control Options

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

10.9.5. 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 and TEG dehydrator 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 flow rate 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.

10.10. FLARE

The flare at the Longhorn Gas Plant will 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 flares are 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.[42]

The following sections present a BACT evaluation for GHG emissions from combustion of pilot gas and vent gas released to the flare during planned startup and shutdown events.

10.10.1. 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;
> Low Carbon Fuel Selection;
> Flare Gas Recovery;
> Good Combustion, Operating, Maintenance Practices;
> Good Flare Design; and
> Limited Vent Gas Releases to Flare.

10.10.1.1. Carbon Capture and Sequestration

A detailed discussion of CCS technology is provided in Section 10.8.

10.10.1.2. Low Carbon Fuel Selection

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

10.10.1.3. 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.

10.10.1.4. 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.

[42] 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.

10.10.1.5. 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, blower controls, and monitoring/control of waste gas heating value.

10.10.1.6. 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.

10.10.2. Step 2 – Eliminate Technically Infeasible Options

The technical infeasibility of CCS and flare gas recovery is discussed below. All other control technologies listed in Step 1 are considered technically feasible.

10.10.2.1. Carbon Capture and Sequestration

With no ability to collect exhaust gas from a flare other than using an enclosure, post combustion capture is not an available control option. Pre-combustion capture has not been demonstrated for removal of CO_2 from intermittent process gas streams routed to a flare. Flaring will be limited to emergency situations and during planned startup and shutdown events of limited duration and vent rates resulting in a very intermittent CO_2 stream; thus, CCS is not considered a technically feasible option. Therefore, it has been eliminated from further consideration in the remaining steps of the analysis.

10.10.2.2. Flare Gas Recovery

Installing a flare gas recovery system to recover flare gas to the fuel gas system is considered a feasible control technology for industrial process flares. Flaring at the Longhorn Gas Plant will be limited to emergency situations and during planned startup and shutdown events of limited duration and vent rates. Due to infrequent MSS activities and the amount of gas sent to the flare, it is technically infeasible to re-route the flare gas to a process fuel system and hence, the gas will be combusted by the flare for control. Therefore, the amount of flare gas produced by this project will not sustain a flare gas recovery system. For this project, flare gas recovery is infeasible.

10.10.3. 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	28% (Natural Gas Versus No. 2 Fuel Oil)	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

Rank	Control Technology	Estimated Reduction	Reduction Details	Reference
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

10.10.4. 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.

10.10.5. Step 5 – Select BACT for the Flares

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

- Low Carbon Fuel Selection;
- Good Combustion, Operating, 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, such as electric compressors, whose MSS emissions are routed to the flare will be operated in 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 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.
- 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

10.11. 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 at the proposed Longhorn Gas Plant include traditional components (valves, flanges, pressure relief valves, pumps, compressors, and connectors), O_2 sensors, and gas chromatographs.

10.11.1. 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.

10.11.1.1. 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.

10.11.1.2. Air-Driven Pneumatic Controllers

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

10.11.1.3. 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.

10.11.1.4. 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.

10.11.1.5. AVO Monitoring Program

Leaking fugitive components can be identified through AVO methods. The fuel gases and some process fluids at the Longhorn Gas Plant 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.

10.11.1.6. 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.

10.11.2. 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.

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

10.11.3.1. Air-Driven Pneumatic Controllers

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

10.11.3.2. LDAR Programs

Instrumented monitoring is effective for identifying leaking CH_4, and although it cannot detect CO_2, it can detect CO_2 if it is a minor component in a highly concentrated hydrocarbon stream.. 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). [43] 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	75%	97%	97%	97%	97%	97%

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

(Gas/Vapor)						
Open-ended Lines	75%	97%	97%	97%	97%	97%
Sampling Connections	75%	97%	97%	97%	97%	97%

10.11.3.3. 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.

10.11.3.4. AVO Monitoring Program

Audio/Visual/Olfactory (AVO) 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 a 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. This method is a requirement of 28LAER TCEQ monitoring program.

10.11.3.5. High Quality Components

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

10.11.4. Step 4 - Evaluate Most Effective Control Options

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

10.11.5. 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 pneumatic devices No process gas will be utilized or vented for these applications. Instrumented monitoring implemented through the TCEQ's 28 LAER program, with control effectiveness of 97% for most equipment, is considered top-level BACT.

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.

10.11.2. 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.

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

10.11.3.1. Air-Driven Pneumatic Controllers

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

10.11.3.2. LDAR Programs

Instrumented monitoring is effective for identifying leaking CH_4, and although it cannot detect CO_2, it can detect CO_2 if it is a minor component in a highly concentrated hydrocarbon stream.. 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). [43] 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	75%	97%	97%	97%	97%	97%

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

ATTACHMENT 2

Permit Application Revised Emission Rate Spreadsheets Section 7

Revised Table 1(a)

Site-Wide Emission Summary for Greenhouse Gas Pollutants

Normal Operations Summary

EPN	FIN	Description	Hourly Emissions (lb/hr)				Annual Emissions (tpy)				GHG BACT Limit[1] (lb/MMscf)
			CO_2	CH_4	N_2O	CO_2e	CO_2	CH_4	N_2O	CO_2e	CO_2e
1	1	TEG-1 Glycol Reboiler	233.78	4.40E-03	4.00E-04	234.00	1,023.96	0.02	1.80E-03	1,024.92	31.73
2	2	TEG Dehydrator During RTO Downtime	0.02	3.13	--	65.81	1.86E-03	0.24	--	5.00	--
3	3	HTR-1 Regen Heater	1,449.44	0.03	2.70E-03	1,450.91	6,348.55	0.13	0.01	6,354.99	196.73
4	4	HTR-2 Hot Oil Heater	11,455.22	0.22	0.02	11,466.44	50,173.86	0.94	0.09	50,223.01	1,554.77
5	2, 15	RTO-1 Regen Thermal Oxidizer	38,296.53	0.34	0.09	38,332.64	167,738.79	1.48	0.41	167,896.94	--
6	6	Flare-1 Flare (Pilot)	61.37	1.16E-03	1.16E-04	61.43	268.79	5.06E-03	5.06E-04	269.05	--
15	15	Amine Still Vent During RTO Downtime	37,579.00	30.67	--	38,223.16	2,856.00	2.33	--	2,904.96	--
16	16	Produced Water Tank 210 bbl	--	--	--	--	--	--	--	--	--
17	17	LP Condensate Tank 1 (During VRU Downtime)	--	--	--	--	--	--	--	--	--
18	18	LP Condensate Tank 2 (During VRU Downtime)	--	--	--	--	--	--	--	--	--
21	21	Open Drain Sump	--	--	--	--	--	--	--	--	--
FUG-1	FUG-1	Plant-wide Fugitive Components	0.34	4.29	--	90.38	1.49	18.78	--	395.86	--
FUG-2	FUG-2	Truck Loading	--	--	--	--	--	--	--	--	--
		Total Normal Operations Emissions	**89,075.70**	**38.68**	**0.12**	**89,924.77**	**228,411.44**	**23.93**	**0.52**	**229,074.74**	**--**

[1] GHG BACT Limit (lb CO_2 / MMscf) = Hourly Emission Rate (lb/hr) / Plant Design Outlet Flowrate (177 MMSCFD) x (24 hr/day)

MSS Operations Summary[1]

EPN	FIN	Description	Hourly Emissions (lb/hr)				Annual Emissions (tpy)			
			CO_2	CH_4	N_2O	CO_2e	CO_2	CH_4	N_2O	CO_2e
5-MSS	5-MSS	RTO-1 Startup	350.67	6.60E-03	6.60E-04	351.01	1.40	2.64E-05	2.64E-06	1.40
6-MSS	6-MSS	Flare-1 Flare MSS	1,631.17	0.06	9.46E-03	1,635.26	9.85	2.95E-04	4.73E-05	9.87
7-MSS	7-MSS	PR-1 16" Reciever	0.46	3.32	--	70.17	0.01	0.09	--	1.82
8-MSS	8-MSS	PR-2 12" Reciever	0.46	3.32	--	70.17	0.01	0.09	--	1.82
20-MSS	20-MSS	Refrigerant Unloading	--	--	--	--	--	--	--	--
FUG-MSS	FUG-MSS	Plant-wide MSS Fugitives	0.73	5.21	--	110.17	8.72E-03	0.06	--	1.32
		Total MSS Emissions	**1,983.49**	**11.91**	**0.01**	**2,236.78**	**11.29**	**0.24**	**4.99E-05**	**16.24**

[1] FUG-MSS does not include pigging or refrigerant unloading since those activities have separate EPNs.

Total Operations Summary

Description	Hourly Emissions (lb/hr)[1]				Annual Emissions (tpy)			
	CO_2	CH_4	N_2O	CO_2e	CO_2	CH_4	N_2O	CO_2e
Normal Operations	89,075.70	38.68	0.12	89,924.77	228,411.44	23.93	0.52	229,074.74
MSS Activities	1,983.49	11.91	0.01	2,236.78	11.29	0.24	4.99E-05	16.24
Total Site-wide Emissions	**181,400.47**	**130.60**	**0.16**	**184,193.84**	**228,422.73**	**24.16**	**0.52**	**229,090.98**

[1] Some MSS emissions may occur at the same time as normal operation. For example, RTO startup (EPN 5-MSS) does not occur at the same time as RTO normal operation (EPN 5). In these cases, the total hourly emissions are calculated based on the maximum emission rates between MSS and normal operation scenarios.

RTO (EPNs 5, 5-MSS)

RTO Criteria Pollutant Summary [1]

Description	EPN	NO_x		CO		VOC		SO_2		H_2S		HAP	
		Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)
RTO - Normal Operation	5	0.11	0.48	3.32	14.55	1.61	7.05	2.81	12.29	0.02	0.07	0.85	3.74
RTO - Startup	5-MSS	0.45	1.80E-03	0.45	1.80E-03	0.02	6.34E-05	1.73E-03	6.92E-06	--	--	--	--
	Total	0.56	0.48	3.77	14.55	1.62	7.05	2.81	12.29	0.02	0.07	0.85	3.74

[1] Total RTO emissions based on emission estimates for each inlet stream to RTO.

RTO (EPNs 5, 5-MSS)

RTO Greenhouse Gas Summary [1]

Description	EPN	CO_2 Hourly (lb/hr)	CO_2 Annual (tpy)	CH_4 Hourly (lb/hr)	CH_4 Annual (tpy)	N_2O Hourly (lb/hr)	N_2O Annual (tpy)	CO_2e Hourly (lb/hr)	CO_2e Annual (tpy)
RTO - Normal Operation	5	38,296.53	167,738.79	0.34	1.48	0.09	0.41	38,332.64	167,896.94
RTO - Startup	5-MSS	350.67	1.40	6.60E-03	2.64E-05	6.60E-04	2.64E-06	351.01	1.40
	Total	38,647.20	167,740.19	0.34	1.48	0.09	0.41	38,683.65	167,898.35

[1] Total RTO emissions based on emission estimates for each inlet stream to RTO.

RTO (EPNs 5, 5-MSS)

RTO Emissions - Greenhouse Gases - Amine Acid Gas Combustion

Input Data

Maximum Amine Acid Gas Flowrate [1] =	7.85	MMscfd (wet)
Hours of Operation =	8,760	hrs/yr

Global Warming Potentials [2]

CO_2	CH_4	N_2O
1	21	310

Compound	Number of Carbon Atoms	Composition [1] (mol %)	DRE [3] (%)	Inlet to RTO [4] (lb/hr)	Controlled GHG Emissions [5, 6] (lb/hr)	Controlled GHG Emissions [5, 6] (tpy)	Converted to CO_2 [6, 7] (lb/hr)	Converted to CO_2 [6, 7] (tpy)
Carbon Dioxide	1	93.74700000	0%	37,579.00	37,579.00	164,596.02	--	--
Methane	1	0.20992500	99%	30.67	0.31	1.34	30.37	133.01
Ethane	2	0.12877500	99%	35.27	--	--	69.83	305.87
Propane	3	0.03723300	99%	14.95	--	--	44.41	194.53
Butanes [8]	4	0.01722241	99%	9.12	--	--	36.11	158.14
Pentanes +	5	0.07019233	99%	56.00	--	--	277.21	1214.18

	Total GHG Emissions [6] (lb/hr)	Total GHG Emissions [6] (tpy)
CO_2 [9]	38,036.93	166,601.76
CH_4 [10]	0.31	1.34
N_2O [11]	0.09	0.39
CO_2e [12]	38,070.97	166,750.87

[1] Maximum amine acid gas flowrate and composition data based on amine acid gas stream from ProMax output data.

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

[3] Destruction efficiency per manufacturer.

[4] Hourly inlet to RTO based on amine acid gas stream from ProMax output data.

[5] Controlled RTO Maximum Potential Hourly Emission Rate (lb/hr) = Inlet to RTO (lb/hr) x (1 - DRE)

$$\text{Example Controlled Methane Hourly Emission Rate (lb/hr)} = \frac{30.67\ \text{lb}}{\text{hr}} \times (1 - 0.99) = \frac{0.31\ \text{lb}}{\text{hr}}$$

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

$$\text{Example Controlled } CO_2 \text{ Annual Emission Rate (tpy)} = \frac{37{,}579.00\ \text{lb}}{\text{hr}} \times \frac{8{,}760\ \text{hr}}{\text{yr}} \times \frac{1\ \text{ton}}{2{,}000\ \text{lb}} = 164{,}596.02\ \text{tpy}$$

[7] During combustion, hydrocarbons in the acid gas waste stream are oxidized to form CO_2 and water vapor.

Per 40 CFR Part 98.233(z)(2)(iii) (Subpart W), for combustion units that combust process vent gas, equation W-39A and W-39B are used to estimate the GHG emissions from additional carbon compounds in the waste gas.

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

$$\text{Example } CH_4 \text{ Converted to } CO_2 \text{ Hourly Emission Rate (lb/hr)} = \frac{30.67\ \text{lb}}{\text{hr}} \times 99\ \% \times 1 = \frac{30.37\ \text{lb}}{\text{hr}}$$

[8] Piperazine has 4 carbon atoms and therefore is included in the Butane total composition.

[9] Total CO_2 is the sum of controlled CO_2 emissions plus the CO_2 emissions from the oxidation of other carbon compounds in the combustion stream.

[10] Total CH_4 is sum of controlled CH_4 emissions.

[11] Per 40 CFR Part 98.233(z)(2)(vi) (Subpart W), for combustion units that combust process vent gas, equation W-40 is used to estimate the N_2O emissions.

Hourly Emission Rate for N_2O (lb/hr) = Acid 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)

$$\text{Example Hourly Emission Rate for } N_2O \text{ (lb/hr)} = \frac{7.85\ \text{MMscf}}{\text{day}} \times \frac{1\ \text{day}}{24\ \text{hrs}} \times \frac{10^6\ \text{scf}}{1\ \text{MMscf}} \times \frac{1.235\text{E-}03\ \text{MMBtu}}{\text{scf}} \times \frac{1.00\text{E-}04\ \text{kg}}{\text{MMBtu}} \times \frac{2.2046\ \text{lb}}{\text{kg}} = \frac{8.90\text{E-}02\ \text{lb}}{\text{hr}}$$

[12] 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

$$\text{Example } CO_2e \text{ Hourly Emission Rate (lb/hr)} = \frac{38{,}036.93\ \text{lb}}{\text{hr}} \times 1 + \frac{0.31\ \text{lb}}{\text{hr}} \times 21 + \frac{8.90\text{E-}02\ \text{lb}}{\text{hr}} \times 310 = \frac{38{,}070.97\ \text{lb}}{\text{hr}}$$

RTO (EPNs 5, 5-MSS)

RTO Emissions - Greenhouse Gases - Dehydrator Waste Gas Combustion

Input Data

Maximum Dehydrator Waste Gas Flowrate [1] = 0.40 MMscfd (wet)

Hours of Operation = 8,760 hrs/yr

Global Warming Potentials [2]

CO_2	CH_4	N_2O
1	21	310

Compound	Number of Carbon Atoms	Composition [1] (mol %)	DRE [3] (%)	Inlet to RTO [4] (lb/hr)	Controlled GHG Emissions [5,6] (lb/hr)	Controlled GHG Emissions [5,6] (tpy)	Converted to CO_2 [6,7] (lb/hr)	Converted to CO_2 [6,7] (tpy)
Carbon Dioxide	1	0.00126829	0%	0.02	0.02	0.11	--	--
Methane	1	0.44455652	99%	3.13	0.03	0.14	3.10	13.58
Ethane	2	0.43008969	99%	5.68	--	--	11.25	49.26
Propane	3	0.45586158	99%	8.83	--	--	26.22	114.85
Butanes	4	0.31166393	99%	7.96	--	--	31.51	138.00
Pentanes +	5	0.99635554	99%	37.88	--	--	187.50	821.23
							Total GHG Emissions [6] (lb/hr)	**(tpy)**
CO_2 [8]							259.60	1,137.03
CH_4 [9]							0.03	0.14
N_2O [10]							4.54E-03	0.02
CO_2e [11]							261.66	1,146.07

[1] Maximum dehydrator waste gas flowrate and composition data based on the dehydrator waste gas stream from ProMax output data.

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

[3] Destruction efficiency per manufacturer.

[4] Hourly inlet to RTO based on dehydrator waste gas stream from ProMax output data.

[5] Controlled RTO Maximum Potential Hourly Emission Rate (lb/hr) = Inlet to RTO (lb/hr) x (1 - DRE)

Example Controlled Methane Hourly Emission Rate (lb/hr) = $\frac{03.13\ \text{lb}}{\text{hr}}$ | (1 - 0.99) = $\frac{0.03\ \text{lb}}{\text{hr}}$

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

Example Controlled CO_2 Annual Emission Rate (tpy) = $\frac{0.02\ \text{lb}}{\text{hr}}$ | $\frac{8{,}760\ \text{hr}}{\text{yr}}$ | $\frac{1\ \text{ton}}{2{,}000\ \text{lb}}$ = 0.11 tpy

[7] During combustion, hydrocarbons in the acid gas waste stream are oxidized to form CO2 and water vapor.

Per 40 CFR Part 98.233(z)(2)(iii) (Subpart W), for combustion units that combust process vent gas, equation W-39A and W-39B are used to estimate the GHG emissions from additional carbon compounds in the waste gas.

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

Example Converted Methane Hourly Emission Rate (lb/hr) = $\frac{3.13\ \text{lb}}{\text{hr}}$ | 99 % | 1 = $\frac{3.10\ \text{lb}}{\text{hr}}$

[8] Total CO_2 is the sum of controlled CO_2 emissions plus the CO_2 emissions from the oxidation of other carbon compounds in the combustion stream.

[9] Total CH_4 is sum of controlled CH_4 emissions.

[10] Per 40 CFR Part 98.233(z)(2)(vi) (Subpart W), for combustion units that combust process vent gas, equation W-40 is used to estimate the GHG emissions.

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 Hourly Emission Rate for N_2O (lb/hr) = $\frac{0.40\ \text{MMscf}}{\text{day}}$ | $\frac{1\ \text{day}}{24\ \text{hrs}}$ | $\frac{10^6\ \text{scf}}{1\ \text{MMscf}}$ | $\frac{1.235\text{E-03 MMBtu}}{\text{scf}}$ | $\frac{1.00\text{E-04 kg}}{\text{MMBtu}}$ | $\frac{2.2046\ \text{lb}}{\text{kg}}$ = $\frac{4.54\text{E-03 lb}}{\text{hr}}$

[11] 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) = $\frac{259.60\ \text{lb}}{\text{hr}}$ | 1 + $\frac{0.03\ \text{lb}}{\text{hr}}$ | 21 + $\frac{4.54\text{E-03 lb}}{\text{hr}}$ | 310 = $\frac{261.66\ \text{lb}}{\text{hr}}$

RTO (EPNs 5, 5-MSS)

RTO Emissions - Greenhouse Gases - Startup [1]

Input Data

Startup Burner Size = 3 MMBtu/hr
Startup Event Duration = 2 hr/event
Startup Event Frequency = 4 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	350.67	1.40
CH_4	6.60E-03	2.64E-05
N_2O	6.60E-04	2.64E-06
CO_2e	351.01	1.40

[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) = $\frac{3 \text{ MMBtu}}{\text{hr}} \times \frac{116.89 \text{ lb}}{\text{MMBtu}} = \frac{350.67 \text{ lb}}{\text{hr}}$

[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) = $\frac{350.67 \text{ lb}}{\text{hr}} \times 1 + \frac{6.60\text{E-}03 \text{ lb}}{\text{hr}} \times 21 + \frac{6.60\text{E-}04 \text{ lb}}{\text{hr}} \times 310 = \frac{351.01 \text{ lb}}{\text{hr}}$

[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) = $\frac{350.67 \text{ lb}}{\text{hr}} \times \frac{2 \text{ hr}}{\text{event}} \times \frac{4 \text{ events}}{\text{yr}} \times \frac{1 \text{ ton}}{2{,}000 \text{ lb}} = \frac{1.40 \text{ ton}}{\text{yr}}$

US EPA ARCHIVE DOCUMENT

Amine Still Vent (EPN 15)

Amine Still Vent Emissions During Scheduled RTO Downtime[1]

Input Data

Maximum amine acid gas flowrate[2] =	5.07	MMscfd (wet)
Scheduled RTO downtime duration =	38	hr/event
Scheduled RTO downtime frequency =	4	events/yr
Hours of Operation =	152	hrs/yr

Compound	Composition[2] (mol %)	Uncontrolled Amine Emissions[2,3,4] (lb/hr)	(tpy)
Propane	0.07101130	18.41	1.40
i-Butane	0.00703255	2.40	0.18
n-Butane	0.02852200	9.75	0.74
i-Pentane	0.00374544	1.59	0.12
n-Pentane	0.00573108	2.43	0.18
Other Hexanes	0.00340137	1.72	0.13
n-Hexane	0.00204024	1.03	7.86E-02
Cyclohexane	0.00419270	2.07	0.16
iC7	0.00053762	0.32	2.41E-02
nC7	0.00014163	0.08	6.34E-03
iC8	0.00009984	0.07	5.10E-03
nC8	0.00006844	0.05	3.92E-03
Isononane	0.00002952	0.02	1.69E-03
Decane	0.00001733	0.01	1.10E-03
Undecane	0.00008222	0.08	5.74E-03
Benzene	0.04525290	20.79	1.58
Toluene	0.06219930	33.70	2.56
Ethylbenzene	0.00237375	1.48	0.11
p-Xylene	0.01636040	10.21	0.78
MDEA	0.00000008	5.82E-05	4.42E-06
Piperazine	0.00000003	1.55E-05	1.18E-06
Hydrogen Sulfide	0.00700000	1.33	0.10
VOC[5]	0.25	106.23	3.04
HAP[6]	0.13	67.22	5.11

[1] During scheduled RTO downtime, the amine acid gas stream will be vented to the atmosphere.

[2] Maximum amine acid gas flowrate, composition data, and uncontrolled hourly emission rates based on amine acid gas stream from ProMax output data. H_2S content estimated as 70 ppmv or 0.007 mol % maximum.

[3] Hourly H_2S Inlet to RTO (lb/hr) = H_2S MW (lb/lb-mol) x H_2S Composition (mol %) x Waste Gas Flowrate (MMscf/day) x (10^6 scf / 1 MMscf) x (1 day / 24 hr) x (1 lb-mol / 379.5 scf)

$$H_2S \text{ Emissions (lb/hr)} = \frac{34.08\text{ lb}}{\text{lb-mol}} \times 0.007\,\% \times \frac{5.07\text{ MMscf}}{\text{day}} \times \frac{10^6\text{ scf}}{1\text{ MMscf}} \times \frac{1\text{ day}}{24\text{ hr}} \times \frac{1\text{ lb-mol}}{379.5\text{ scf}} = \frac{1.33\text{ lb}}{\text{hr}}$$

[4] Maximum Potential Annual Rate (tpy) = Hourly Rate (lb/hr) x RTO Downtime Duration (hr/event) x RTO Downtime Frequency (events/yr) x (1 ton / 2,000 lb)

$$\text{Example Propane Annual Emission Rate (tpy)} = \frac{18.41\text{ lb}}{\text{hr}} \times \frac{38\text{ hr}}{\text{event}} \times \frac{4\text{ events}}{\text{yr}} \times \frac{1\text{ ton}}{2{,}000\text{ lb}} = \frac{1.40\text{ ton}}{\text{yr}}$$

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

[6] Total HAP taken as the sum of all hazardous air pollutants.

Amine Still Vent (EPN 15)

Amine Still Vent Emissions During Scheduled RTO Downtime - Greenhouse Gases[1]

Input Data

Scheduled RTO downtime duration = 38 hr/event

Scheduled RTO downtime frequency = 4 events/yr

Hours of Operation = 152 hrs/yr

Global Warming Potentials[2]

CO_2	CH_4	N_2O
1	21	310

Compound	Amine Still Vent Emissions	
	(lb/hr)[3,4]	(tpy)[5]
CO_2	37,579.00	2,856.00
CH_4	30.67	2.33
N_2O	--	--
CO_2e	38,223.16	2,904.96

[1] During scheduled RTO downtime, the amine acid gas stream will be vented to the atmosphere.

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

[3] Maximum Potential Hourly Emission Rate (lb/hr) taken from ProMax output data.

[4] 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

$$\text{Example } CO_2e \text{ Hourly Emission Rate (lb/hr)} = \frac{37{,}579.00 \text{ lb}}{\text{hr}} \Big| \ 1 \quad + \quad \frac{30.67 \text{ lb}}{\text{hr}} \Big| \ 21 \quad = \quad \frac{38{,}223.16 \text{ lb}}{\text{hr}}$$

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

$$\text{Example } CO_2 \text{ Annual Emission Rate (tpy)} = \frac{37{,}579.00 \text{ lb}}{\text{hr}} \Big| \frac{38 \text{ hr}}{\text{event}} \Big| \frac{4 \text{ events}}{\text{yr}} \Big| \frac{1 \text{ ton}}{2{,}000 \text{ lb}} = \frac{2{,}856.00 \text{ ton}}{\text{yr}}$$

Flare (EPNs 6, 6-MSS)

Flare Emissions - Pilot Gas - Greenhouse Gases

Input Data

Gas Stream Heat Value =	1,000	Btu/scf
Number of Pilots =	3	
Average Flowrate =	175	scf/hr-pilot
Sweep Gas =	375	scf/hr
Maximum Flowrate =	0.833	scfm/pilot
Hourly Flowrate [1] =	525	scf/hr
Hours of Operation =	8,760	hrs/yr
Annual Flowrate [2] =	4.599	MMscf/yr
Gas Stream Heat Input [3] =	0.53	MMBtu/hr
Gas Stream Heat Input [4] =	4,599	MMBtu/yr

Natural Gas External Combustion Greenhouse Gas Emission Factors [5]

Units [6]	CO_2	CH_4	N_2O
kg/MMBtu	53.02	1.00E-03	1.00E-04
GWP [7]	1	21	310
lb/MMBtu [8]	116.89	2.20E-03	2.20E-04

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

$$\text{Hourly Flowrate (scf/hr)} = \frac{175.0\text{ scf}}{\text{hr-pilot}} \left| \; 3 \right. = \frac{525\text{ scf}}{\text{hr}}$$

[2] Annual Flowrate (MMscf/yr) = Hourly Flowrate (scf/hr) x Annual Operation (hr/yr) x (1 MMscf /10⁶scf)

$$\text{Annual Flowrate (MMscf/yr)} = \frac{525\text{ scf}}{\text{hr}} \left| \frac{8{,}760\text{ hr}}{\text{yr}} \right| \frac{1\text{ MMscf}}{10^6\text{ scf}} = \frac{4.599\text{ MMscf}}{\text{yr}}$$

[3] Hourly Gas Stream Heat Input (MMBtu/hr) = Hourly Flowrate (scf/hr) x Gas Stream Heat Value (Btu/scf) x (1 MMscf /10⁶scf)

$$\text{Example Hourly Gas Stream Heat Input (MMBtu/hr)} = \frac{525\text{ scf}}{\text{hr}} \left| \frac{1{,}000\text{ Btu}}{\text{scf}} \right| \frac{1\text{ MMBtu}}{10^6\text{ Btu}} \quad \frac{0.53\text{ MMBtu}}{\text{hr}}$$

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

$$\text{Example Annual Gas Stream Heat Input (MMBtu/yr)} = \frac{0.53\text{ MMBtu}}{\text{hr}} \left| \frac{8{,}760\text{ hrs}}{\text{yr}} \right. = \frac{4{,}599\text{ MMBtu}}{\text{yr}}$$

[5] Per 40 CFR Part 98.233(z)(1) (Subpart W), if the fuel combusted in the stationary or portable equipment is listed in Table C-1 of Subpart C, then emissions are calculated per Subpart C.

[6] Emission factors obtained from 40 CFR 98 Subpart C Tables C-1 and C-2 for natural gas.

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

[8] 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)

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

US EPA ARCHIVE DOCUMENT

Flare (EPNs 6, 6-MSS)

Flare Emissions - Pilot Gas - Greenhouse Gases

Compound	Flare Emissions [1, 2, 3]	
	(lb/hr)	(tpy)
CO_2	61.37	268.79
CH_4	1.16E-03	5.06E-03
N_2O	1.16E-04	5.06E-04
CO_2e	61.43	269.05

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

Example CO_2 Hourly Emission Rate (lb/hr) = $\frac{0.53\ \text{MMBtu}}{\text{hr}} \times \frac{116.89\ \text{lb}}{\text{MMBtu}} = \frac{61.37\ \text{lb}}{\text{hr}}$

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

Example CO_2 Annual Emission Rate (tpy) = $\frac{61.37\ \text{lb}}{\text{hr}} \times \frac{8{,}760\ \text{hr}}{\text{yr}} \times \frac{1\ \text{ton}}{2{,}000\ \text{lb}} = \frac{268.79\ \text{ton}}{\text{yr}}$

[3] CO_2e emissions based on GWPs for each greenhouse gas pollutant.

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

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{61.37\ \text{lb}}{\text{hr}} \times 1 + \frac{1.16\text{E-03}\ \text{lb}}{\text{hr}} \times 21 + \frac{1.16\text{E-04}\ \text{lb}}{\text{hr}} \times 310 = \frac{61.43\ \text{lb}}{\text{hr}}$

Flare (EPNs 6, 6-MSS)

Flare Emissions - Residue Compressor Blowdowns - Greenhouse Gases[1]

Input Data

Number of Compressors =	3	
Annual Number of Events per Compressor =	3	events/compressor-yr
Total Number of Events =	9	events/year
Estimated Event Duration[2] =	1	hr/event
Event Flowrate =	2,000	scf/event
Annual Event Hours =	9	hrs/yr
Gas Stream Heat Value =	1,000	Btu/scf
Hourly Flowrate[3] =	6,000	scf/hr
Annual Flowrate[4] =	0.018	MMscf/yr
Hourly Gas Stream Heat Input[5] =	6.00	MMBtu/hr
Annual Gas Stream Heat Input[6] =	54.00	MMBtu/yr

Natural Gas External Combustion Greenhouse Gas Emission Factors[7]

Units[8]	CO_2	CH_4	N_2O
kg/MMBtu	53.02	1.00E-03	1.00E-04
GWP[9]	1	21	310
lb/MMBtu[10]	116.89	2.20E-03	2.20E-04

[1] Blowdowns from the electric driven compressors are routed to the flare.

[2] For events lasting less than 1 hour, it is assumed that no more than 1 event occurs per hour.

[3] The maximum hourly flowrate occurs during a plant shudown when all compressors are shutdown at the same time.
Hourly Flowrate (scf/hr) = Event Flowrate (scf/event) / Event Duration (hrs/event) * Number of Compressors

$$\text{Hourly Flowrate (scf/hr)} = \frac{2{,}000 \text{ scf}}{\text{event}} \left| \frac{\text{event}}{1 \text{ hr}} \right| 3 \text{ compressors} = \frac{6{,}000 \text{ scf}}{\text{hr}}$$

[4] Annual Flowrate (MMscf/yr) = Event Flowrate (scf/event) x Total Number of Event (events/yr) x (1 MMscf / 10^6 scf)

$$\text{Annual Flowrate (MMscf/yr)} = \frac{2{,}000 \text{ scf}}{\text{event}} \left| \frac{9 \text{ events}}{\text{yr}} \right| \frac{1 \text{ MMscf}}{10^6 \text{ scf}} = \frac{0.018 \text{ MMscf}}{\text{yr}}$$

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

$$\text{Hourly Gas Stream Heat Input (MMBtu/hr)} = \frac{6000 \text{ scf}}{\text{hr}} \left| \frac{1{,}000 \text{ Btu}}{\text{scf}} \right| \frac{1 \text{ MMBtu}}{10^6 \text{ Btu}} \quad \frac{6.00 \text{ MMBtu}}{\text{hr}}$$

[6] Annual Gas Stream Heat Input (MMBtu/yr) = Annual Flowrate (MMscf/yr) x Gas Stream Heat Value (Btu/scf)

$$\text{Annual Gas Stream Heat Input (MMBtu/yr)} = \frac{0.018 \text{ MMscf}}{\text{yr}} \left| \frac{1{,}000 \text{ Btu}}{\text{scf}} \right. = \frac{54.00 \text{ MMBtu}}{\text{yr}}$$

[7] Per 40 CFR Part 98.233(z)(1) (Subpart W), if the fuel combusted in the stationary or portable equipment is listed in Table C-1 of Subpart C, then emissions are calculated per Subpart C.

[8] Emission factors obtained from 40 CFR 98 Subpart C Tables C-1 and C-2 for natural gas.

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

[10] 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)

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

Flare (EPNs 6, 6-MSS)

Flare Emissions - Residue Compressor Blowdowns - Greenhouse Gases

Compound	Flare Emissions[1,2,3]	
	(lb/hr)	(tpy)
CO_2	701.34	3.16
CH_4	0.01	5.94E-05
N_2O	1.32E-03	5.94E-06
CO_2e	702.03	3.16

[1] Maximum Potential Hourly Emission Rate (lb/hr) = Hourly Heat Input (MMBtu/hr) x Emission Factor (lb/MMBtu)

Example CO_2 Hourly Emission Rate (lb/hr) = $\frac{6.00\ \text{MMBtu}}{\text{hr}} \times \frac{116.89\ \text{lb}}{\text{MMBtu}} = \frac{701.34\ \text{lb}}{\text{hr}}$

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

Example CO_2 Annual Emission Rate (tpy) = $\frac{54.00\ \text{MMBtu}}{\text{yr}} \times \frac{116.89\ \text{lb}}{\text{MMBtu}} \times \frac{1\ \text{ton}}{2{,}000\ \text{lb}} = \frac{3.16\ \text{ton}}{\text{yr}}$

[3] CO_2e emissions based on GWPs for each greenhouse gas pollutant.

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

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{701.34\ \text{lb}}{\text{hr}} \times 1 + \frac{1.32\text{E-}02\ \text{lb}}{\text{hr}} \times 21 + \frac{1.32\text{E-}03\ \text{lb}}{\text{hr}} \times 310 = \frac{702.03\ \text{lb}}{\text{hr}}$

Flare (EPNs 6, 6-MSS)

Flare Emissions - Refrigerant Compressor Blowdowns - Greenhouse Gases[1]

Input Data

Number of Compressors =	3	
Annual Number of Events per Compressor =	3	events/compressor-yr
Total Number of Events =	9	events/year
Estimated Event Duration[2] =	1	hr/event
Event Flowrate =	2,000	scf/event
Annual Event Hours =	9	hrs/yr
Gas Stream Heat Value =	1,000	Btu/scf
Hourly Flowrate[3] =	6,000	scf/hr
Annual Flowrate[4] =	0.018	MMscf/yr
Hourly Gas Stream Heat Input[5] =	6.00	MMBtu/hr
Annual Gas Stream Heat Input[6] =	54.00	MMBtu/yr

Propane External Combustion Greenhouse Gas Emission Factors[7]

Units[8]	CO_2	CH_4	N_2O
kg/MMBtu	61.46	3.00E-03	6.00E-04
GWP[9]	1	21	310
lb/MMBtu[10]	135.49	6.60E-03	1.32E-03

[1] Blowdowns from the electric driven compressors are routed to the flare.

[2] For events lasting less than 1 hour, it is assumed that no more than 1 event occurs per hour.

[3] The maximum hourly flowrate occurs during a plant shudown when all compressors are shutdown at the same time.

Hourly Flowrate (scf/hr) = Event Flowrate (scf/event) / Event Duration (hrs/event) * Number of Compressors

$$\text{Hourly Flowrate (scf/hr)} = \frac{2{,}000\ \text{scf}}{\text{event}} \cdot \frac{\text{event}}{1\ \text{hr}} \cdot 3\ \text{compressors} = \frac{6{,}000\ \text{scf}}{\text{hr}}$$

[4] Annual Flowrate (MMscf/yr) = Event Flowrate (scf/event) x Total Number of Event (events/yr) x (1 MMscf /10^6scf)

$$\text{Annual Flowrate (MMscf/yr)} = \frac{2{,}000\ \text{scf}}{\text{event}} \cdot \frac{9\ \text{events}}{\text{yr}} \cdot \frac{1\ \text{MMscf}}{10^6\ \text{scf}} = \frac{0.018\ \text{MMscf}}{\text{yr}}$$

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

$$\text{Hourly Gas Stream Heat Input (MMBtu/hr)} = \frac{6000\ \text{scf}}{\text{hr}} \cdot \frac{1{,}000\ \text{Btu}}{\text{scf}} \cdot \frac{1\ \text{MMBtu}}{10^6\ \text{Btu}} \quad \frac{6.00\ \text{MMBtu}}{\text{hr}}$$

[6] Annual Gas Stream Heat Input (MMBtu/yr) = Annual Flowrate (MMscf/yr) x Gas Stream Heat Value (Btu/scf)

$$\text{Annual Gas Stream Heat Input (MMBtu/yr)} = \frac{0.018\ \text{MMscf}}{\text{yr}} \cdot \frac{1{,}000\ \text{Btu}}{\text{scf}} = \frac{54.00\ \text{MMBtu}}{\text{yr}}$$

[7] Per 40 CFR Part 98.233(z)(1) (Subpart W), if the fuel combusted in the stationary or portable equipment is listed in Table C-1 of Subpart C, then emissions are calculated per Subpart C.

[8] Emission factors obtained from 40 CFR 98 Subpart C Tables C-1 and C-2 for propane gas.

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

[10] 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)

$$\text{Example } CO_2 \text{ Emission Factor (lb/MMBtu)} = \frac{61.46\ \text{kg}}{\text{MMBtu}} \cdot \frac{2.2046\ \text{lb}}{\text{kg}} = \frac{135.49\ \text{lb}}{\text{MMBtu}}$$

Flare (EPNs 6, 6-MSS)

Flare Emissions - Refrigerant Compressor Blowdowns - Greenhouse Gases[1]

Compound	Flare Emissions[1,2,3]	
	(lb/hr)	(tpy)
CO_2	812.94	3.66
CH_4	0.04	1.78E-04
N_2O	7.92E-03	3.56E-05
CO_2e	816.23	3.67

[1] Maximum Potential Hourly Emission Rate (lb/hr) = Hourly Heat Input (MMBtu/hr) x Emission Factor (lb/MMBtu)

Example CO_2 Hourly Emission Rate (lb/hr) = $\frac{6.00\ \text{MMBtu}}{\text{hr}} \times \frac{135.49\ \text{lb}}{\text{MMBtu}} = \frac{812.94\ \text{lb}}{\text{hr}}$

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

Example CO_2 Annual Emission Rate (tpy) = $\frac{54.00\ \text{MMBtu}}{\text{yr}} \times \frac{135.49\ \text{lb}}{\text{MMBtu}} \times \frac{1\ \text{ton}}{2{,}000\ \text{lb}} = \frac{3.66\ \text{ton}}{\text{yr}}$

[3] CO_2e emissions based on GWPs for each greenhouse gas pollutant.

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

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{812.94\ \text{lb}}{\text{hr}} \times 1 + \frac{3.96\text{E-}02\ \text{lb}}{\text{hr}} \times 21 + \frac{7.92\text{E-}03\ \text{lb}}{\text{hr}} \times 310 = \frac{816.23\ \text{lb}}{\text{hr}}$

Flare (EPNs 6, 6-MSS)

Flare Emissions - Pigging - Greenhouse Gases[1]

Input Data

	Pigging 12"	Pigging 16"	
Annual Number of Events =	52	52	events/year
Estimated Event Duration[2] =	1	1	hr/event
Event Flowrate =	360	640	scf/event
Annual Event Hours =	52	52	hrs/yr
Gas Stream Heat Value =	1,000	1,000	Btu/scf
Hourly Flowrate[3] =	360	640	scf/hr
Annual Flowrate[4] =	0.019	0.033	MMscf/yr
Hourly Gas Stream Heat Input[5] =	0.36	0.64	MMBtu/hr
Annual Gas Stream Heat Input[6] =	18.72	33.28	MMBtu/yr

Natural Gas External Combustion Greenhouse Gas Emission Factors[7]

Units[8]	CO_2	CH_4	N_2O
kg/MMBtu	53.02	1.00E-03	1.00E-04
GWP[9]	1	21	310
lb/MMBtu[10]	116.89	2.20E-03	2.20E-04

[1] Blowdowns from the electric driven compressors are routed to the flare.

[2] For events lasting less than 1 hour, it is assumed that no more than 1 event occurs per hour.

[3] Hourly Flowrate (scf/hr) = Event Flowrate (scf/event) / Event Duration (hrs/event) * Number of Compressors

$$\text{Hourly Flowrate (scf/hr)} = \frac{0{,}360\ \text{scf}}{\text{event}} \times \frac{\text{event}}{1\ \text{hr}} = \frac{360\ \text{scf}}{\text{hr}}$$

[4] Annual Flowrate (MMscf/yr) = Event Flowrate (scf/event) x Total Number of Event (events/yr) x (1 MMscf / 10^6 scf)

$$\text{Annual Flowrate (MMscf/yr)} = \frac{0{,}360\ \text{scf}}{\text{event}} \times \frac{52\ \text{events}}{\text{yr}} \times \frac{1\ \text{MMscf}}{10^6\ \text{scf}} = \frac{0.019\ \text{MMscf}}{\text{yr}}$$

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

$$\text{Hourly Gas Stream Heat Input (MMBtu/hr)} = \frac{360\ \text{scf}}{\text{hr}} \times \frac{1{,}000\ \text{Btu}}{\text{scf}} \times \frac{1\ \text{MMBtu}}{10^6\ \text{Btu}} \quad \frac{0.36\ \text{MMBtu}}{\text{hr}}$$

[6] Annual Gas Stream Heat Input (MMBtu/yr) = Annual Flowrate (MMscf/yr) x Gas Stream Heat Value (Btu/scf)

$$\text{Annual Gas Stream Heat Input (MMBtu/yr)} = \frac{0.019\ \text{MMscf}}{\text{yr}} \times \frac{1{,}000\ \text{Btu}}{\text{scf}} = \frac{18.72\ \text{MMBtu}}{\text{yr}}$$

[7] Per 40 CFR Part 98.233(z)(1) (Subpart W), if the fuel combusted in the stationary or portable equipment is listed in Table C-1 of Subpart C, then emissions are calculated per Subpart C.

[8] Emission factors obtained from 40 CFR 98 Subpart C Tables C-1 and C-2 for natural gas.

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

[10] 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)

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

Flare (EPNs 6, 6-MSS)

Flare Emissions - Pigging - Greenhouse Gases[1]

Compound	Flare Emissions[1, 2, 3]	
	(lb/hr)	(tpy)
CO_2	116.89	3.04
CH_4	2.20E-03	5.72E-05
N_2O	2.20E-04	5.72E-06
CO_2e	117.00	3.04

[1] Maximum Potential Hourly Emission Rate (lb/hr) = (Hourly Heat Input for the 12" Pipe + Hourly Heat Input for the 16" Pipe)(MMBtu/hr) x Emission Factor (lb/MMBtu)

Example CO_2 Hourly Emission Rate (lb/hr) = $\dfrac{(0.36\ \text{MMBtu/hr} + 0.64\text{MMBtu/hr})}{} \Big| \dfrac{116.89\ \text{lb}}{\text{MMBtu}} = \dfrac{116.89\ \text{lb}}{\text{hr}}$

[2] Maximum Potential Annual Emission Rate (tpy) = (Annual Heat Input for the 12" Pipe + Annual Heat Input for the 16" Pipe)(MMBtu/yr) x Emission Factor (lb/MMBtu) x (1 ton / 2,000 lb)

Example CO_2 Annual Emission Rate (tpy) = $\dfrac{(18.72\ \text{MMBtu/yr} + 33.28\text{MMBtu/yr})}{} \Big| \dfrac{116.89\ \text{lb}}{\text{MMBtu}} \Big| \dfrac{1\ \text{ton}}{2{,}000\ \text{lb}} = \dfrac{3.04\ \text{ton}}{\text{yr}}$

[3] CO_2e emissions based on GWPs for each greenhouse gas pollutant.

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

Example CO_2e Hourly Emission Rate (lb/hr) = $\dfrac{116.89\ \text{lb}}{\text{hr}} \Big| 1 + \dfrac{2.20\text{E-}03\ \text{lb}}{\text{hr}} \Big| 21 + \dfrac{2.20\text{E-}04\ \text{lb}}{\text{hr}} \Big| 310 = \dfrac{117.00\ \text{lb}}{\text{hr}}$

TCEQ

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	February 2012	Permit No.:	TBD	Regulated Entity No.	TBD
Area Name:	Targa Gas Processing LLC - Longhorn Gas Plant			Customer Reference No.	TBD

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	
EPN (A)	FIN (B)	NAME (C)		Pounds per hour (A)	TPY (B)
1	1	TEG-1 Glycol Reboiler	CO_2	233.78	1,023.96
			CH_4	<0.01	0.02
			N_2O	<0.01	<0.01
			CO_2e	234.00	1,024.92
2	2	TEG Dehydrator During RTO Downtime	CO_2	0.02	<0.01
			CH_4	3.13	0.24
			CO_2e	65.81	5.00
3	3	HTR-1 Regen Heater	CO_2	1,449.44	6,348.55
			CH_4	0.03	0.13
			N_2O	<0.01	0.01
			CO_2e	1,450.91	6,354.99
4	4	HTR-2 Hot Oil Heater	CO_2	11,455.22	50,173.86
			CH_4	0.22	0.94
			N_2O	0.02	0.09
			CO_2e	11,466.44	50,223.01
5	2, 15	RTO-1 Regen Thermal Oxidizer	CO_2	38,296.53	167,738.79
			CH_4	0.34	1.48
			N_2O	0.09	0.41
			CO_2e	38,332.64	167,896.94
6	6	Flare-1 Flare (Pilot)	CO_2	61.37	268.79
			CH_4	<0.01	<0.01
			N_2O	<0.01	<0.01
			CO_2e	61.43	269.05

TCEQ

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	February 2012	Permit No.:	TBD	Regulated Entity No.	TBD
Area Name:	Targa Gas Processing LLC - Longhorn Gas Plant			Customer Reference No.	TBD

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	
EPN (A)	FIN (B)	NAME (C)		Pounds per hour (A)	TPY (B)
15	15	Amine Still Vent During RTO Downtime	CO_2	37,579.00	2,856.00
			CH_4	30.67	2.33
			CO_2e	38,223.16	2,904.96
FUG-1	FUG-1	Plant-wide Fugitive Components	CO_2	0.34	1.49
			CH_4	4.29	18.78
			CO_2e	90.38	395.86
5-MSS	5-MSS	RTO-1 Startup	CO_2	350.67	1.40
			CH_4	<0.01	<0.01
			N_2O	<0.01	<0.01
			CO_2e	351.01	1.40
6-MSS	6-MSS	Flare-1 Flare MSS	CO_2	1631.17	9.85
			CH_4	0.06	<0.01
			N_2O	<0.01	<0.01
			CO_2e	1635.26	9.87
7-MSS	7-MSS	PR-1 16" Reciever	CO_2	0.46	0.01
			CH_4	3.32	0.09
			CO_2e	70.17	1.82
8-MSS	8-MSS	PR-2 12" Reciever	CO_2	0.46	0.01
			CH_4	3.32	0.09
			CO_2e	70.17	1.82
FUG-MSS [1]	FUG-MSS	Plant-wide MSS Fugitives	CO_2	0.73	<0.01
			CH_4	5.21	0.06
			CO_2e	110.17	1.32

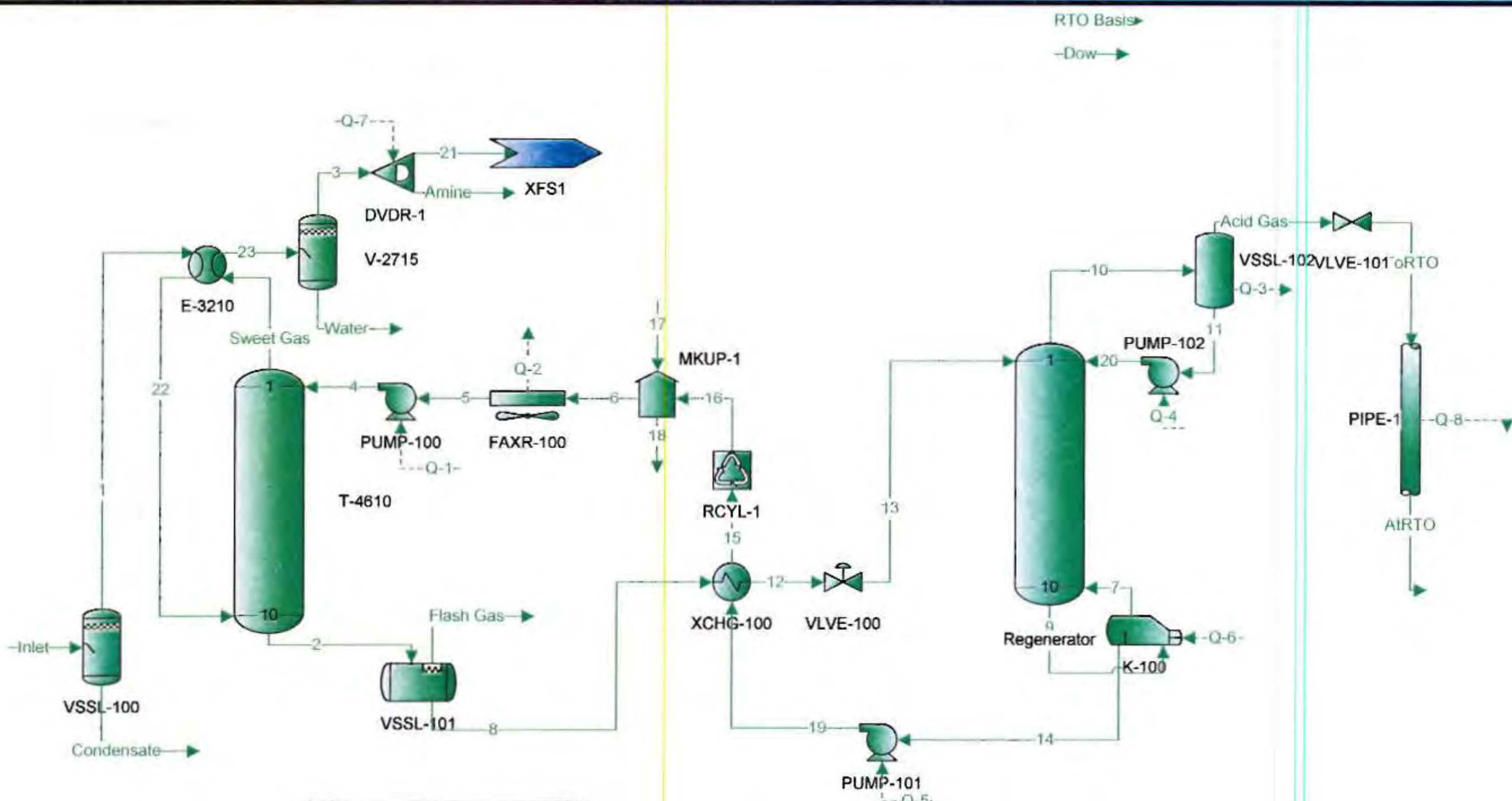
[1] FUG-MSS does not include pigging since those activities have separate EPNs.

ATTACHMENT 3

Revised Amine Treater PROMAX Run Appendix A

Amine Treating
Plant Schematic

Client Name:	3.9 CO2 55 wtPC 70F	Job:	
Location:			
Flowsheet:	Amine Treating		



Sour CO2	0.039
Sweet CO2	1.8402e-005
Lean Loading	0.020971
Rich Loading	0.40508

	Max VOC Case	Max GHG Case
Process Streams	**AtRTO**	**AtRTO**
Mole Fraction	%	%
Nitrogen	0.000128768	0.000066175
Carbon Dioxide	93.3318	93.7470
Methane	0.370683	0.209925
Ethane	0.2572580	0.1287750
Propane	0.0710113	0.0372330
i-Butane	0.00703255	0.00342981
n-Butane	0.02852200	0.01379260
i-Pentane	0.003745440	0.001223020
n-Pentane	0.005731080	0.002004060
i-C6	3.40137E-03	1.31310E-03
n-Hexane	2.04024E-03	7.93918E-04
Cyclohexane	4.19270E-03	1.93898E-03
i-C7	0.00054	0.00019
n-C7	0.0001416	0.0000500
iC8	0.000099838	0.000040586
iC7	1.21448E-05	5.21089E-06
n-Octane	6.84388E-05	3.10308E-05
Isononane	0.00002952	0.00001317
Decane	1.73298E-05	7.66678E-06
Undecane	8.22242E-05	3.91300E-05
Benzene	0.045252900	0.023839400
Toluene	0.06219930	0.03153880
Ethylbenzene	2.37375E-03	9.68758E-04
m-Xylene	1.63604E-02	6.19733E-03
MDEA	8.29911E-08	5.59177E-08
Piperazine	3.06880E-08	1.14022E-08
Water	5.78727E+00	5.78955E+00
Molar Flow	lbmol/h	lbmol/h
Nitrogen	0.00075721	0.00060275
Carbon Dioxide	548.834	853.884
Methane	2.17979	1.91208
Ethane	1.512800	1.172930
Propane	0.417579	0.339133
i-Butane	0.04135460	0.03124010
n-Butane	0.1677230	0.1256280
i-Pentane	0.02202490	0.01113970
n-Pentane	0.03370130	0.01825380
i-C6	0.020001600	0.011960200
n-Hexane	1.19975E-02	7.23131E-03
Cyclohexane	2.46550E-02	1.76610E-02
i-C7	0.0032	0.0017
n-C7	0.0008328	0.0004550
iC8	0.00058709	0.00036967
iC7	0.000071417	0.000047463
n-Octane	4.02452E-04	2.82641E-04
Isononane	0.0001736	0.0001199
Decane	1.01907E-04	6.98320E-05
Undecane	4.83516E-04	3.56412E-04
Benzene	0.26610800	0.21713800
Toluene	0.36576000	0.28726800
Ethylbenzene	1.39587E-02	8.82383E-03
m-Xylene	9.62067E-02	5.64477E-02
MDEA	4.88026E-07	5.09320E-07
Piperazine	1.80460E-07	1.03856E-07
Water	3.40318E+01	5.27335E+01
Mass Fraction	%	%
Nitrogen	0.000085006	0.000043659
Carbon Dioxide	96.7948	97.1660

Methane	0.1401360	0.0793134
Ethane	0.1822910	0.0911929
Propane	0.0737902	0.0386664
i-Butane	0.00963232	0.00469486
n-Butane	0.03906600	0.01887980
i-Pentane	0.006368070	0.002078130
n-Pentane	0.009744090	0.003405260
i-C6	0.006907370	0.002664960
n-Hexane	4.14323E-03	1.61127E-03
Cyclohexane	8.31520E-03	3.84314E-03
i-C7	0.00127	0.00044
n-C7	0.0003344	0.0001179
iC8	0.000268748	0.000109184
iC7	3.26918E-05	1.40184E-05
n-Octane	2.06849E-04	9.37300E-05
Isononane	0.0000892	0.0000398
Decane	5.81056E-05	2.56905E-05
Undecane	3.02871E-04	1.44046E-04
Benzene	0.083298900	0.043855300
Toluene	0.13505200	0.06843800
Ethylbenzene	5.93871E-03	2.42218E-03
m-Xylene	4.09309E-02	1.54952E-02
MDEA	2.33048E-07	1.56927E-07
Piperazine	6.22914E-08	2.31303E-08
Water	2.45692E+00	2.45638E+00
Mass Flow	**lb/h**	**lb/h**
Nitrogen	0.0212121	0.0168850
Carbon Dioxide	24153.9	37579.0
Methane	34.9692	30.6745
Ethane	45.4883	35.2689
Propane	18.41340	14.95430
i-Butane	2.403620	1.815740
n-Butane	9.74841	7.30178
i-Pentane	1.589070	0.803719
n-Pentane	2.431510	1.316990
i-C6	1.7236500	1.0306700
n-Hexane	1.03389E+00	6.23161E-01
Cyclohexane	2.07495E+00	1.48634E+00
i-C7	0.317	0.172
n-C7	0.08345	0.04560
iC8	0.067063	0.042227
iC7	0.0081578	0.0054216
n-Octane	0.05161650	0.03625010
Isononane	0.02227	0.01538
Decane	0.01449950	0.00993582
Undecane	0.075577500	0.055710100
Benzene	20.786200	16.961100
Toluene	33.70060	26.46840
Ethylbenzene	1.48193000	0.93678200
m-Xylene	10.213800000	5.992770000
MDEA	0.000058154	0.000060692
Piperazine	0.000015544	0.000008946
Water	613.09300000	950.00800000

Process Streams		**AtRTO**	**AtRTO**
Property	**Units**		
Temperature	°F	120.001	119.989
Pressure	psia	19.1968	18.4996
Mole Fraction Vapor	%	100	100
Mole Fraction Light Liquid	%	0	0

Mole Fraction Heavy Liquid	%	0	0
Molecular Weight	lb/lbmol	42.4350	42.4609
Mass Density	lb/ft^3	0.131741	0.127007
Molar Flow	lbmol/h	588.046	910.839
Mass Flow	lb/h	24953.7	38675.1
Vapor Volumetric Flow	ft^3/h	189415	304512
Liquid Volumetric Flow	gpm	23615.4	37965.1
Std Vapor Volumetric Flow	MMSCFD	5.35570	8.29558
Std Liquid Volumetric Flow	sgpm	61.0965	94.4546
Compressibility		0.994002	0.994231
Specific Gravity		1.46516	1.46606
Enthalpy	Btu/h	-96318800	-149727000
Mass Enthalpy	Btu/lb	-3.85990E+03	-3.87141E+03
Mass Cp	Btu/(lb*°F)	0.22	0.22
Ideal Gas CpCv Ratio		1.278580	1.279540
Dynamic Viscosity	cP	0.01609	0.01612
Kinematic Viscosity	cSt	7.6249100	7.9234000
Thermal Conductivity	Btu/(h*ft*°F)	0.01064	0.01062
Surface Tension	lbf/ft		
Net Ideal Gas Heating Value	Btu/ft^3	16.2825	8.24782
Net Liquid Heating Value	Btu/lb	46.14830	-25.50140
Gross Ideal Gas Heating Value	Btu/ft^3	20.4922	11.8261
Gross Liquid Heating Value	Btu/lb	83.79410	6.47860
Normal Vapor Volumetric Flow	MMCFD	5.0671	7.8486

ATTACHMENT 4

Permit Application Revised BACT Cost Analysis Appendix E

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	110	miles
Average Diameter of Pipeline	8	inches
CO2 emissions from vents	162,905.13	tons/year
CO2 capture efficiency	90%	
Captured CO2	146,614.61	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)	$10,973,371.60
Labor	$ Diameter (inches), Length (miles)	$341,627 + $1.85 x L x (343.2 x D^2 + 2,074 x D + 170,013)	$42,785,581.30
Miscellaneous	$ Diameter (inches), Length (miles)	$150,166 + $1.58 x L x (8,417 x D + 7,234)	$13,110,432.00
Right of Way	$ Diameter (inches), Length (miles)	$48,037 + $1.20 x L x (577 x D + 29,788)	$4,589,365.00
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	$949,520.00
		Total CCS Cost	$73,669,537.90

Amortized CCS Cost

Equipment Life (years)[2]	10
Interest rate	0.07
Capital Recovery Factor (CRF)[3]	0.142
Total Capital Investment (TCI)	$72,720,017.90
Amortized Installation Cost (TCI*CRF)	$10,326,242.54
Total CCS Annualized Cost	**$11,275,762.54**

Amortized Project Cost (without CCS)

Equipment Life[2]	20
Interest rate	0.07
Capital Recovery Factor (CRF)[3]	0.094
Total Capital Investment (TCI)	$79,500,000.00
Amortized Installation Cost (TCI*CRF)	$7,473,000.00
Annual Operating Cost Estimation	$6,000,000.00
Total Project Annualized Cost	**$13,473,000.00**

[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.