December 20, 2012

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

RE: *Update to GHG PSD Permit Application*
Targa Gas Processing LLC
Longhorn Gas Plant

Dear Ms. Wilson:

Targa Gas Processing LLC (Targa) is proposing to update their GHG PSD Permit Application with the inclusion of a flare (EPNs: 9 and 9-MSS) to combust the amine and triethylene glycol (TEG) dehydrator vent streams during the regenerative thermal oxidizer (RTO, EPN 5) downtime. With this update, Targa has included the following attachments to supplement the initial application:

Attachment 1: Updated Process Description
Attachment 2: Updated Process Flow Diagram
Attachment 3: Updated Plot Plan
Attachment 4: Updated Emissions Calculations
Attachment 5: Updated Emission Point Summary [TCEQ Table 1(a)]
Attachment 6: BACT for the Flare

The requested updates will not impact any of the existing sources of regulatory applicability determinations made in the initial application for the Longhorn Gas Plant.

Thank you in advance for your review of the permit application and your consideration of the requested changes. If you have any questions or comments about the information presented in this letter, please do not hesitate to call me at (713) 584-1422 or Ms. Whitney Boger, Trinity, at (972) 661-8100.

Sincerely,

TARGA GAS PROCESSING LLC

Melanie Roberts

Enclosure

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

ATTACHMENT 1

Updated Process Description

The 200 MMscfd Longhorn Gas Plant will consist of inlet separation facilities, an amine treating unit, glycol unit, cryogenic processing skid and supporting equipment. The supporting or auxiliary equipment consists of a hot oil heater, refrigeration system, regeneration heater, residue compression, regenerative thermal oxidizer, flares, and storage and truck loading and unloading facilities for consumable chemicals. A process flow diagram is included in Attachment 2.

Inlet And Separation

Gas will flow into the plant from either of two delivery points through high pressure pipelines equipped with onsite pipeline pig receivers (EPN 7-MSS, EPN 8-MSS). Gas from the pig receivers flows into the inlet slug catcher for liquid removal. The gas is then measured and goes through the Plant Inlet Separator for removal of any additional water, solids or liquids. Gas then flows to the Plant Inlet Filter/Separator for filtering of smaller particles of water and solids. Condensate from all inlet separation equipment is pumped back into a pipeline for delivery and handling at an existing facility located offsite.

Gas Treating

After inlet separation and filtration, the inlet gas flows into the Amine Contactor, where the gas is contacted with an aqueous solution of UCARSOL AP-814 amine to remove CO_2. CO_2 exits with the amine from the bottom of the contactor and is heated and regenerated using closed hot oil system in the Amine Regenerator. Hot oil is circulated and supplied by the Heating Medium Heater (EPN 4). The CO_2 released from the regeneration process is routed to the onsite Regenerative Thermal Oxidizer, (RTO, EPN 5), where the vent gas is combusted and burned. When the RTO is down for maintenance, the vent gas is routed to the flare (EPN 9-MSS). Treated gas (less CO_2) exits the Amine Contactor and is routed to the Treated Gas Coolers where it is cooled with ambient air. Any condensed water drops out in the Treated Gas Scrubber. Water that does not drop out is recycled back to the amine process for reuse.

Gas Dehydrator

Gas from the Treated Gas Scrubber then goes to the TEG Contactor where water removal is accomplished by contacting with triethylene glycol (TEG). The TEG is then regenerated in a 2.0 MMBtu/hr direct fired reboiler (EPN 1). Flash vapors from this unit go through an exchanger to remove condensables and then are routed back to the reboiler burner as fuel. Water removed from the TEG in the reboiler is cooled and any residual vapors are routed to the RTO (EPN 5) for combustion. During RTO maintenance the residual vapors are vented to the flare (EPN 9-MSS). Dehydrated gas leaves the contactor and is exchanged with incoming glycol in a side mounted exchanger and then routed to the Mole Sieve Inlet Separator to recover any glycol carryover. Any recovered glycol/water is recycled back to the TEG system for reuse.

Gas exits the Mole Sieve Inlet Separator and flows into the Inlet Filter / Separator where it is again filtered prior to entering the Mole Sieve Dehydrator Beds. The gas flows into two (2) of the three (3) Mole Sieve Dehydrators for removal of any traces of water prior to the cryogenic process. Each dehydrator contains molecular sieve dehydration beads that absorb trace amounts of water from the gas stream. Two vessels will be used to dehydrate inlet gas while the third vessel is being regenerated. Dehydrated high pressure gas is used for regeneration. The regeneration gas is compressed by a Sundyne Compressor. The compressed gas flows to the Regeneration Gas Heater (EPN 3). The heater duty is not a 24 hour, continuous duty operation but only needed a few hours per day per bed. The hot gas flows from the heater to the dehydrator vessel being regenerated. The water is removed from the molecular sieve by evaporation. The hot gas and vaporized water flow to the Regeneration Gas Cooler, where the gas is cooled and the water is condensed. The cool regeneration gas stream flows to the Regeneration Gas Scrubber where condensed water is level controlled to the closed drain system flash tank and then to the plant waste water tank. The cooled gas recycles to the inlet of the plant upstream of the Inlet Filter/Separator. Dehydrated gas from the mole sieve beds flows into the Mole Sieve Dust Filters to remove any mole sieve particles prior to entry into the cryogenic process.

Cryogenic Process

Gas flow into the Cryogenic Process is split to (2) plate fin type exchangers, Normally 60% will go to the Inlet Gas Exchanger, while the remainder flows to the Gas/Product Exchanger, then the Demethanizer reboiler, and then to the Demethanizer Side Reboiler or Heater. The Exchangers are combined into one plate fin exchanger. Gas vapor and liquid from the exchangers are combined and enter the Demethanizer Tower. The inlet gas is further cooled by heat exchange with propane refrigerant in the Inlet Gas Chiller. There are (3) 1500HP electric driven screw compressors that supply the process with refrigerant propane for cooling of the gas. Any heavier components collected in the refrigeration compressor scrubbers or system goes to the closed drain system flash tank. Refrigerant propane is loaded by truck into the Refrigerant Accumulator. Vapor and liquids from the chiller then flow to the Cold Separator. The Cold Separator is used to separate vapor and liquid hydrocarbons that have condensed as a result of chilling in the exchangers. Most of the vapor exiting the Cold Separator flows into the Expander side of the Expander/Booster Compressor where the temperature and pressure are reduced and enter the Demethanizer Tower. A portion of the Cold Separator liquids combines with a portion of the Cold Separator overhead vapors and flows to the Demethanizer Feed Subcooler where it is cooled with cold residue gas. The pressure is reduced and the stream feeds the top of the Demethanizer Tower. The remainder of the Cold Separator Liquid is level controlled to reduce the pressure and enters the Demethanizer Tower.

The Demethanizer Tower is a packed tower with a bottoms reboiler and a side reboiler (also known as a side heater). Liquids leaving the bottom of the tower flow to the Product Surge Tank. The product is then pumped by the Product Booster Pumps which are tandem seal centrifugal pumps, through the Gas/Product Exchanger where the product is heated by exchange with the inlet gas and then to the Product Pipeline Pumps which are tandem seal multistage centrifugal pumps. Overhead gas vapors (residue) from the Demethanizer Tower flows to the Demethanizer Feed Subcooler, then to the Inlet Gas Exchanger where the temperature is increased by heat exchange with the inlet gas. The residue leaving this exchanger is compressed by the Booster Compressor side of the Expander/Booster Compressor. Boosted residue is cooled in the Booster Compressor After-cooler and then flows to the residue compressors. Residue compressors comprise (3)-5,000 hp electric motor-driven reciprocating compressors which take the residue gas from plant residue pressure to pipeline sales pressure. Any compressor liquids accumulated from scrubbers is routed to the closed drain system flash tank. After cooling with fin fan units the residue gas is delivered by pipeline to the sales point offsite.

Closed Drain System

The closed drain system is designed with a flash tank that allows flash vapors to go to the plant fuel system via pressure feed or a vapor recovery unit. Liquids from the flash tank go to the low pressure condensate tanks (EPNs 17, 18). Water is separated out from the condensate and is drained to the waste water tank (EPN 16). Condensate is loaded out via trucks (FUG-2). Flash, working, and breathing vapors from the low pressure condensate tanks are controlled by the vapor recovery unit (VRU) and delivered to the plant fuel system.

Open Drain System

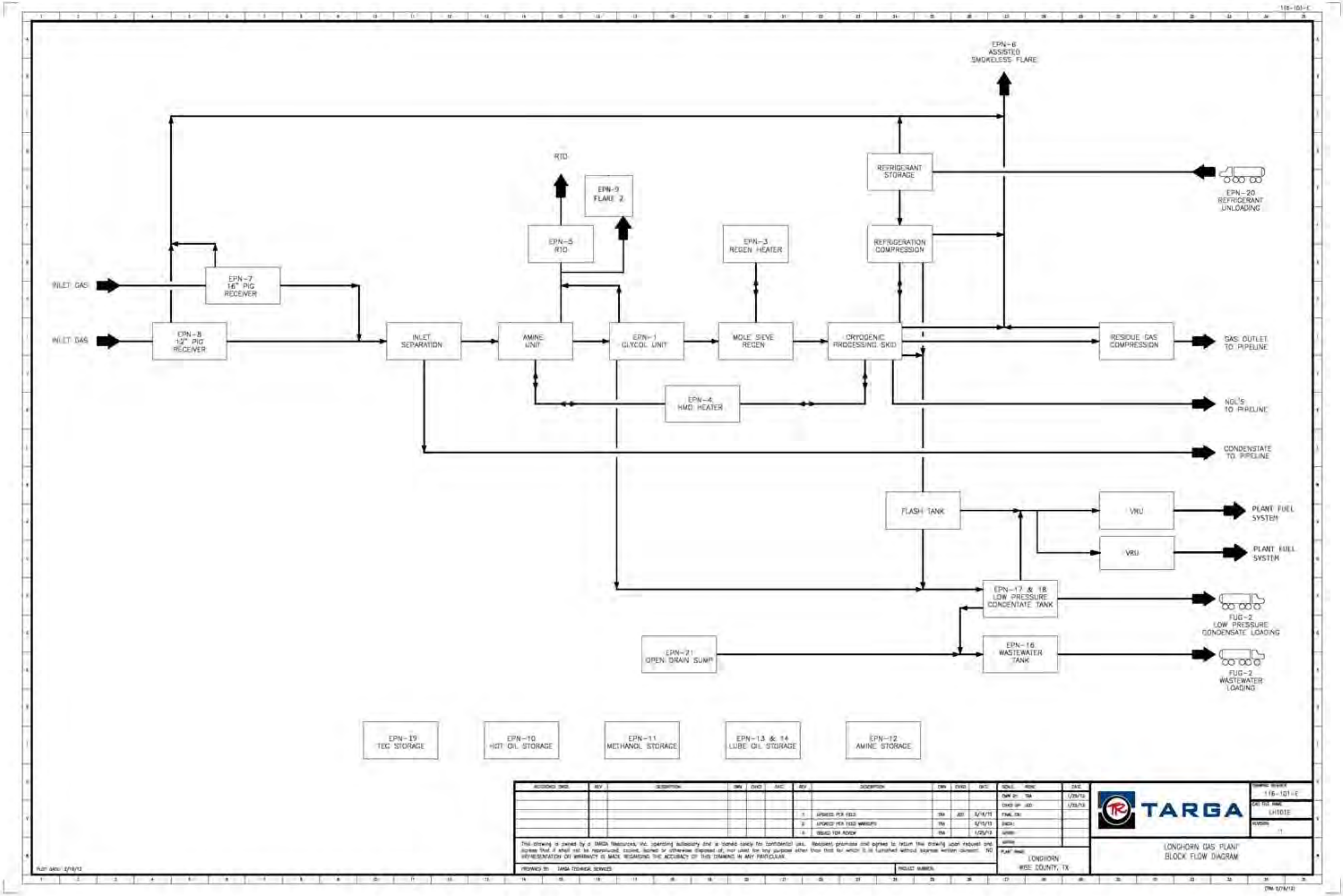
The facility is equipped with an open (atmospheric) drain system to collect rain water and skid drain liquids to the open drain sump (EPN 21). The water collected in the sump flows to the waste water tank (EPN 16). Water in the waste water tank is loaded onto trucks for offsite handling.

Flare System

Two 40 CFR §60.18 compliant flares (EPNs 6 and 9) will be located on the facility site. The flares are air assisted and designed for smokeless operation. All pressure safety valves (PSV) containing heavier than air hydrocarbons, refrigeration system PSVs, compressor blowdown and residue compressor blowdown vapors are routed to the EPN 6 flare. Emissions resulting from the amine unit and TEG dehydrator during RTO downtime are routed to the EPN 9 flare.

ATTACHMENT 2

Updated Process Flow Diagram

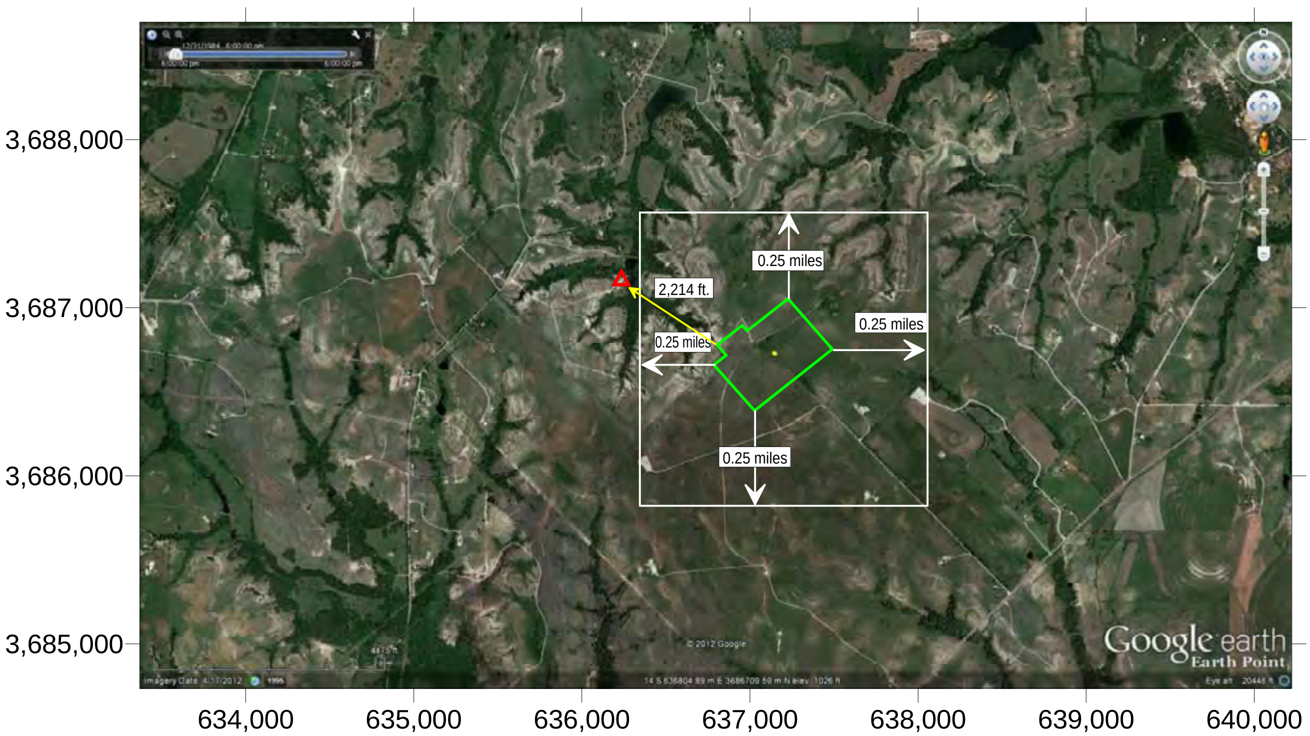


EPN-6 ASSISTED SMOKELESS FLARE
RTO
EPN-9 FLARE 2
REFRIGERANT STORAGE
EPN-20 REFRIGERANT UNLOADING
EPN-5 RTO
EPN-3 REGEN HEATER
REFRIGERATION COMPRESSION
INLET GAS
EPN-7 16" PIG RECEIVER
INLET GAS
EPN-8 12" PIG RECEIVER
INLET SEPARATION
AMINE UNIT
EPN-1 GLYCOL UNIT
MOLE SIEVE REGEN
CRYOGENIC PROCESSING SKID
RESIDUE GAS COMPRESSION
GAS OUTLET TO PIPELINE
EPN-4 HMO HEATER
NGL'S TO PIPELINE
CONDENSATE TO PIPELINE
FLASH TANK
VRU
PLANT FUEL SYSTEM
VRU
PLANT FUEL SYSTEM
EPN-17 & 18 LOW PRESSURE CONDENSATE TANK
FUG-2 LOW PRESSURE CONDENSATE LOADING
EPN-21 OPEN DRAIN SUMP
EPN-16 WASTEWATER TANK
FUG-2 WASTEWATER LOADING
EPN-19 TEG STORAGE
EPN-10 HOT OIL STORAGE
EPN-11 METHANOL STORAGE
EPN-13 & 14 LUBE OIL STORAGE
EPN-12 AMINE STORAGE
TARGA
116-101-E
LH101E
LONGHORN WISE COUNTY, TX
LONGHORN GAS PLANT BLOCK FLOW DIAGRAM

ATTACHMENT 3

Updated Plot Plan

Figure 3-1
Targa Gas Processing LLC
Longhorn Plant Area Map



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

Legend

Property Line

Sensitive Receptor

ATTACHMENT 4

Updated Emission Calculations

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
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	--
9	9	Flare- 2 Flare (Pilot)	18.23	3.43E-04	3.43E-05	18.25	79.87	1.50E-03	1.50E-04	79.95	--
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	**51,514.91**	**4.88**	**0.12**	**51,654.05**	**225,635.30**	**21.36**	**0.52**	**226,244.73**	**--**

[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
9-MSS	9-MSS	Flare 2 - Amine & Dehydrator During RTO Downtime	38,291.15	0.34	0.09	38,327.26	2,910.13	0.03	7.11E-03	2,912.87
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	**40,274.64**	**12.25**	**0.10**	**40,564.04**	**2,921.42**	**0.26**	**7.16E-03**	**2,929.11**

[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	51,514.91	4.88	0.12	51,654.05	225,635.30	21.36	0.52	226,244.73
MSS Activities	40,274.64	12.25	0.10	40,564.04	2,921.42	0.26	7.16E-03	2,929.11
Total Site-wide Emissions	**106,991.04**	**32.65**	**0.26**	**107,756.49**	**228,556.72**	**21.62**	**0.52**	**229,173.84**

[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.

Flare (EPNs 6, 6-MSS, 9, 9-MSS)

Flare 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)
Flare 1 - Pilot Gas	6	0.07	0.32	0.14	0.63	4.87E-04	2.13E-03	2.76E-03	0.01	3.00E-05	1.31E-04	--	--
Flare 1 - MSS	6-MSS	1.79	6.07E-03	3.58	0.01	13.99	0.30	0.03	4.74E-05	3.43E-04	5.14E-07	6.20E-03	8.06E-03
Flare 2 - Pilot Gas	9	0.02	0.09	0.04	0.19	1.45E-04	6.34E-04	8.21E-04	3.60E-03	8.91E-06	3.90E-05	--	--
Flare 2 - MSS (RTO Downtime)	9-MSS	0.64	0.05	1.28	0.10	2.95	0.22	2.64	0.20	0.03	2.18E-03	1.69	0.13
	Total	2.53	0.47	5.05	0.93	16.94	0.52	2.67	0.22	0.03	2.35E-03	1.70	0.14

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

Flare (EPNs 6, 6-MSS, 9, 9-MSS)

Flare Greenhouse Gas Summary [1]

Description	EPN	CO_2		CH_4		N_2O		CO_2e	
		Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)
Flare 1 - Pilot Gas	6	61.37	268.79	1.16E-03	5.06E-03	1.16E-04	5.06E-04	61.43	269.05
Flare 1 - MSS	6-MSS	1,631.17	9.85	5.50E-02	2.95E-04	9.46E-03	4.73E-05	1,635.26	9.87
Flare 2 - Pilot Gas	9	18.23	79.87	3.43E-04	1.50E-03	3.43E-05	1.50E-04	18.25	79.95
Flare 2 - MSS (RTO Downtime)	9-MSS	38,291.15	2,910.13	0.34	0.03	0.09	7.11E-03	38,327.26	2,912.87
	Total	40,001.92	3,268.64	0.39	0.03	0.10	7.82E-03	40,042.20	3,271.74

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

Flare 2 (EPNs 9, 9-MSS)

Flare 2 Emissions - Greenhouse Gases - Amine Acid Gas Combustion

Input Data

Maximum Amine Acid Gas Flowrate [1] =	7.85	MMscfd (wet)
Hours of Operation =	152	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 Flare [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	2,856.00	--	--
Methane	1	0.20992500	99%	30.67	0.31	0.02	30.37	2.31
Ethane	2	0.12877500	99%	35.27	--	--	69.83	5.31
Propane	3	0.03723300	99%	14.95	--	--	44.41	3.38
Butanes [8]	4	0.01722241	98%	9.12	--	--	35.74	2.72
Pentanes +	5	0.07019233	98%	56.00	--	--	274.41	20.86

	Total GHG Emissions [6] (lb/hr)	Total GHG Emissions [6] (tpy)
CO_2 [9]	38,033.77	2,890.57
CH_4 [10]	0.31	0.02
N_2O [11]	0.09	0.01
CO_2e [12]	38,067.81	2,893.15

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

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

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

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)

Example Controlled CO_2 Annual Emission Rate (tpy) = $\frac{37{,}579.00\ \text{lb}}{\text{hr}} \times \frac{152\ \text{hr}}{\text{yr}} \times \frac{1\ \text{ton}}{2{,}000\ \text{lb}} = 2{,}856.00\ \text{tpy}$

[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 Flare (lb/hr) x DRE (%) x Carbon Count (#)

Example CH_4 Converted to CO_2 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)

Example Hourly Emission Rate for N_2O (lb/hr) = $\frac{7.85\ \text{MMscf}}{\text{day}} \times \frac{1\ \text{day}}{24\ \text{hrs}} \times \frac{10^6\ \text{scf}}{1\ \text{MMscf}} \times \frac{1.235\text{E-03 MMBtu}}{\text{scf}} \times \frac{1.00\text{E-04 kg}}{\text{MMBtu}} \times \frac{2.2046\ \text{lb}}{\text{kg}} = \frac{0.09\ \text{lb}}{\text{hr}}$

[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

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{38{,}033.77\ \text{lb}}{\text{hr}} \times 1 + \frac{0.31\ \text{lb}}{\text{hr}} \times 21 + \frac{0.09\ \text{lb}}{\text{hr}} \times 310 = \frac{38{,}067.81\ \text{lb}}{\text{hr}}$

Flare 2 (EPNs 9, 9-MSS)

Flare 2 Emissions - Greenhouse Gases - Dehydrator Waste Gas Combustion

Input Data

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

Hours of Operation = 152 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 Flare [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	1.86E-03	--	--
Methane	1	0.44455652	99%	3.13	0.03	2.38E-03	3.10	0.24
Ethane	2	0.43008969	99%	5.68	--	--	11.25	0.85
Propane	3	0.45586158	99%	8.83	--	--	26.22	1.99
Butanes	4	0.31166393	98%	7.96	--	--	31.19	2.37
Pentanes +	5	0.99635554	98%	37.88	--	--	185.60	14.11

	Total GHG Emissions [6] (lb/hr)	Total GHG Emissions [6] (tpy)
CO_2 [8]	257.38	19.56
CH_4 [9]	0.03	2.38E-03
N_2O [10]	4.54E-03	3.45E-04
CO_2e [11]	259.45	19.72

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

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

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

Example Controlled Methane Hourly Emission Rate (lb/hr) = $\frac{3.13 \text{ lb}}{\text{hr}} \times (1 - 0.99) = \frac{0.03 \text{ lb}}{\text{hr}}$

[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) = $\frac{0.02 \text{ lb}}{\text{hr}} \times \frac{152 \text{ hr}}{\text{yr}} \times \frac{1 \text{ ton}}{2{,}000 \text{ lb}} = 1.86\text{E-03 tpy}$

[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 Flare (lb/hr) x DRE (%) x Carbon Count (#)

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

[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) = $\frac{0.40 \text{ MMscf}}{\text{day}} \times \frac{1 \text{ day}}{24 \text{ hrs}} \times \frac{10^6 \text{ scf}}{1 \text{ MMscf}} \times \frac{1.235\text{E-03 MMBtu}}{\text{scf}} \times \frac{1.00\text{E-04 kg}}{\text{MMBtu}} \times \frac{2.2046 \text{ lb}}{\text{kg}} = \frac{4.54\text{E-03 lb}}{\text{hr}}$

[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) = $\frac{257.38 \text{ lb}}{\text{hr}} \times 1 + \frac{0.03 \text{ lb}}{\text{hr}} \times 21 + \frac{4.54\text{E-03 lb}}{\text{hr}} \times 310 = \frac{259.45 \text{ lb}}{\text{hr}}$

Flare 2 (EPNs 9, 9-MSS)

Flare Emissions - Pilot Gas - Greenhouse Gases

Input Data

Gas Stream Heat Value =	1,000	Btu/scf
Number of Pilots =	2	
Average Flowrate =	78	scf/hr-pilot
Maximum Flowrate =	0.833	scfm/pilot
Hourly Flowrate [1] =	156	scf/hr
Hours of Operation =	8,760	hrs/yr
Annual Flowrate [2] =	1.367	MMscf/yr
Gas Stream Heat Input [3] =	0.16	MMBtu/hr
Gas Stream Heat Input [4] =	1,367	MMBtu/yr

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

$$\text{Hourly Flowrate (scf/hr)} = \frac{78.0\text{ scf}}{\text{hr-pilot}} \times 2 = \frac{156\text{ scf}}{\text{hr}}$$

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

$$\text{Annual Flowrate (MMscf/yr)} = \frac{156\text{ scf}}{\text{hr}} \times \frac{8{,}760\text{ hr}}{\text{yr}} \times \frac{1\text{ MMscf}}{10^6\text{ scf}} = \frac{1.367\text{ MMscf}}{\text{yr}}$$

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

$$\text{Example Hourly Gas Stream Heat Input (MMBtu/hr)} = \frac{156\text{ scf}}{\text{hr}} \times \frac{1{,}000\text{ Btu}}{\text{scf}} \times \frac{1\text{ MMBtu}}{10^6\text{ Btu}} \quad \frac{0.16\text{ MMBtu}}{\text{hr}}$$

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

$$\text{Example Annual Gas Stream Heat Input (MMBtu/yr)} = \frac{0.16\text{ MMBtu}}{\text{hr}} \times \frac{8{,}760\text{ hrs}}{\text{yr}} = \frac{1{,}367\text{ MMBtu}}{\text{yr}}$$

[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)

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

Flare 2 (EPNs 9, 9-MSS)

Flare Emissions - Pilot Gas - Greenhouse Gases

Compound	Flare Emissions [1, 2, 3] (lb/hr)	Flare Emissions [1, 2, 3] (tpy)
CO_2	18.23	79.87
CH_4	3.43E-04	1.50E-03
N_2O	3.43E-05	1.50E-04
CO_2e	18.25	79.95

[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) = $\frac{0.16\ \text{MMBtu}}{\text{hr}} \times \frac{116.89\ \text{lb}}{\text{MMBtu}} = \frac{18.23\ \text{lb}}{\text{hr}}$

[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) = $\frac{18.23\ \text{lb}}{\text{hr}} \times \frac{8{,}760\ \text{hr}}{\text{yr}} \times \frac{1\ \text{ton}}{2{,}000\ \text{lb}} = \frac{79.87\ \text{ton}}{\text{yr}}$

[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) = $\frac{18.23\ \text{lb}}{\text{hr}} \times 1 + \frac{3.43\text{E-}04\ \text{lb}}{\text{hr}} \times 21 + \frac{3.43\text{E-}05\ \text{lb}}{\text{hr}} \times 310 = \frac{18.25\ \text{lb}}{\text{hr}}$

Flare 2 Total GHG Emissions Summary

CO_2		CH_4		N_2O		CO_2e	
(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
38309.39	2990.00	0.34	0.03	0.09	7.26E-03	38345.51	2992.82

ATTACHMENT 5

Updated Emission Point Summary [TCEQ Table 1(a)]

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	November 2012	Permit No.:	TBD	Regulated Entity No.	RN106346745
Area Name:	Targa Gas Processing LLC - Longhorn Gas Plant			Customer Reference No.	CN604041806

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
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
9	9	Flare- 2 Flare (Pilot)	CO_2	18.23	79.87
			CH_4	<0.01	<0.01
			N_2O	<0.01	<0.01
			CO_2e	18.25	79.95

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	November 2012	Permit No.:	TBD	Regulated Entity No.	RN106346745
Area Name:	Targa Gas Processing LLC - Longhorn Gas Plant			Customer Reference No.	CN604041806

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)
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
9-MSS	9-MSS	Flare 2 - Amine & Dehydrator During RTO Downtime	CO_2	38291.15	2910.13
			CH_4	0.34	0.03
			N_2O	0.09	<0.01
			CO_2e	38327.26	2912.87
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.

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	November 2012	Permit No.:	TBD	Regulated Entity No.	RN106346745
Area Name:	Targa Gas Processing LLC - Longhorn Gas Plant			Customer Reference No.	CN604041806

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

AIR CONTAMINANT DATA			EMISSION POINT DISCHARGE PARAMETERS										
1. Emission Point			4. UTM Coordinates of Emission Point			Source							
						5. Building Height (Feet)	6. Height Above Ground (Feet)	7.Stack Exit Data			8. Fugitives		
EPN (A)	FIN (B)	NAME (C)	Zone	East (Meters)	North (Meters)			Diameter (Feet) (A)	Velocity (fps) (B)	Temperature (°f) (C)	Length (ft.) (A)	Width (ft.) (B)	Axis Degrees (C)
1	1	TEG-1 Glycol Reboiler	14	637217	3686920		16.67	1.33	7.94	750			
3	3	HTR-1 Regen Heater	14	637219	3686918		18.00	2.50	6.45	680			
4	4	HTR-2 Hot Oil Heater	14	637224	3686927		124.00	6.75	13.89	550			
5	2, 15	RTO-1 Regen Thermal Oxidizer	14	637197	3686923		30.00	3.50	51.97	600			
6	6	Flare-1 Flare (Pilot)	14	637210	3686911		75.00	1.67	65.60	1832			
9	9	Flare- 2 Flare (Pilot)	14	637195	3686975		40.00	1.50	65.60	1,832			
11	11	MEOH-1 Methanol Storage	14	637246	3686806		4.00	0.003	0.003	Ambient			
16	16	Produced Water Tank 210 bbl	14	637195	3686975		15	0.003	0.003	Ambient			
17	17	LP Condensate Tank 1	14	637358	3686796		15	0.003	0.003	Ambient			
18	18	LP Condensate Tank 2	14	637361	3686800		15	0.003	0.003	Ambient			
21	21	Open Drain Sump	14	637364	3686804		1	0.003	0.003	Ambient			
FUG-1	FUG-1	Plant-wide Fugitive Components	14	637129	3686779		10				1,090	1,033	314
FUG-2	FUG-2	Truck Loading	14	637130	3686575		3				50	50	314
5-MSS	5-MSS	RTO-1 Startup	14	637359	3686789		30	3.50	51.97	600			
6-MSS	6-MSS	Flare-1 Flare MSS	14	637210	3686911		75.00	1.67	65.60	1832			
7-MSS	7-MSS	PR-1 16" Reciever	14	637282	3686889		10.00				10	10	0
8-MSS	8-MSS	PR-2 12" Reciever	14	637005	3686726		10.00				10	10	0
9-MSS	9-MSS	Flare 2 - Amine & Dehydrator During RTO Downtime	14	637195	3686975		40.00	1.50	65.60	1,832			
20-MSS	20-MSS	Refrigerant Unloading	14	637145	3686959		4.00				10	10	0
FUG-MSS	FUG-MSS	Plant-wide MSS Fugitives	14	637130	3686575		10				1,090	1,033	314

ATTACHMENT 6

BACT for Flare

The additional flare at the Longhorn Gas Plant will be used to destroy the off-gas produced during RTO downtime for the amine and TEG dehydrator vent streams. GHG emissions will be generated by the combustion of natural gas in the pilot 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 flare is an example of a control device in which the control of certain pollutants causes the formation of collateral GHG emissions. Specifically, the control of CH_4 in the process gas at the flare results in the creation of additional CO_2 emissions via the combustion reaction mechanism. However, given the relative GWPs of CO_2 and CH_4 and the destruction of VOCs, it is appropriate to apply combustion controls to CH_4 emissions even though it will form additional CO_2 emissions.[1]

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.

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.

Carbon Capture and Sequestration

Carbon sequestration is a method to reduce GHG emissions. It complements two other major approaches for GHG reduction, namely improving energy efficiency and increasing the use of non-carbon energy sources. CO_2 is captured at its source and subsequently stored in non-atmospheric reservoirs. Targa conducted research and analysis to determine the technical feasibility of CO_2 capture and transfer. Since most of the CO_2 emissions from the proposed project are generated from the amine unit, Targa conducted studies to evaluate potential options to capture and transfer the CO_2 to an off-site facility for injection.

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.

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[1] 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.

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.

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.

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.

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.

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.

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.

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, shutdown, and maintenance 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.

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
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

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.

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 a manner to minimize the frequency and duration of such MSS activities and therefore, the amount of MSS vent gas released to the flare.

Compliance with work practices is noted below:

- Flare shall have a minimum destruction and removal efficiency (DRE) of 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