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

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

11.3. AMINE UNIT

The amine unit in Train 5 of the Mont Belvieu Plant will be used to absorb CO_2 from a fractionated ethane gas stream to produce a treated gas stream with lower CO_2 content. Because the amine unit is designed to remove CO_2 from the fractionated gas stream, the generation of CO_2 is inherent to the process, and a reduction of the CO_2 emissions by process changes would reduce the process efficiency. This would result in more CO_2 in the ethane and natural gas liquids that would eventually be emitted.

11.3.1. Step 1 – Identify All Available Control Technologies

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

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

11.3.1.1. Carbon Capture and Sequestration

Targa conducted research and analysis to determine the technical feasibility of CO_2 capture and transfer. Most of the CO_2 emissions from the proposed project are generated from the hot oil heaters. A detailed evaluation is included in section 11.2.1.1 for the Hot Oil Heaters.

11.3.1.2. Flare

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

11.3.1.3. Thermal Oxidizer

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

11.3.1.4. Condenser

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

11.3.1.5. Proper Design and Operations

The amine unit 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 the amine stream, which would increase VOC and GHG emissions into the atmosphere.

11.3.1.6. Use of Tank Flash Gas Recovery Systems

The amine unit will be equipped with a flash tank. 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 as fuel, instead of venting to the atmosphere. The use of flash tanks increases the effectiveness of other downstream control devices.

11.3.2. Step 2 – Eliminate Technically Infeasible Options

All control options identified in Step 1 are technically feasible.

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

The control options for minimizing GHG emissions from the amine unit 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 5.1.1.5 Improved Maintenance
3	Condenser	< 0.25%	Reduction of CH_4 in acid 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

Rank	Control Technology	Estimated CO_2e Reduction	Reduction Details	Reference
5	Thermal Oxidizer	--	Reduction in acid gas CH_4. Increase in CO_2 due to acid gas combustion	Vendor Data
6	Flare	--	Reduction in acid gas CH_4. Increase in CO_2 due to acid gas, supplemental fuel, and pilot gas combustion.	http://www.tceq.texas.gov/permitting/air/guidance/newsourcereview/flares/ and vendor data

11.3.4. Step 4 – Evaluate Most Effective Control Options

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

11.3.4.1. Carbon Capture and Sequestration

Information on CCS is included in Section 11.2.4.

11.3.5. Step 5 – Select BACT for the Amine Unit

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

- Thermal Oxidizer for amine unit still vent (FIN AU-4);
- Proper Design and Operation;
- Use of Tank Flash Gas Recovery System;
- Use of a Condenser;
- Flare for amine still vent during startup and RTO scheduled maintenance downtime; and
- Flare for amine flash tank during startup;

11.4. TEG DEHYDRATOR

The TEG Dehydration Unit in Train 5 of the Mont Belvieu Plant will be used to absorb water from a fractionated ethane gas stream to produce a treated gas stream with lower water content to meet product specifications.

11.4.1. 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;
- Vent Gas Recovery;
- Proper Design and Operations;
- Use of Tank Flash Gas Recovery System; and
- Use of Regeneration Vent Recovery System.

11.4.1.1. Carbon Capture and Sequestration

Targa conducted research and analysis to determine the technical feasibility of CO_2 capture and transfer. Most of the CO_2 emissions from the proposed project are generated from the hot oil heaters. A detailed evaluation is included in section 11.2.1.1 for the Hot Oil Heaters.

11.4.1.2. Flare

One option to reduce the GHGs emitted from the Mont Belvieu Plant is to send stripped dehydrator waste gases to a flare. The flare is an example of a control device in which the control of certain pollutants causes the formation of collateral GHG emissions. However, given the relative GWPs of CO_2 and CH_4 and the destruction of VOCs and HAPs, it is appropriate to apply combustion controls to CH_4 emissions even though it will form additional CO_2 emissions. In general, flares have a destruction efficiency rate (DRE) of 98%, resulting in minor CH_4 emissions from the process flare due to incomplete combustion of CH_4. Additionally, the flare requires the use of a continuous pilot ignition system or equivalent that results in additional GHG emissions.

11.4.1.3. Thermal Oxidizer

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

11.4.1.4. Condenser

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

11.4.1.5. Proper Design and Operations

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. By minimizing the circulation rate, the equipment avoids pulling out additional VOCs and GHGs in the glycol stream, which would increase VOC and GHG emissions into the atmosphere.

11.4.1.6. Use of Tank Flash Gas Recovery Systems

The TEG dehydration unit will be equipped with a flash tank. The flash tank 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 as fuel, instead of venting to the atmosphere. The use of flash tanks increases the effectiveness of other downstream control devices.

11.4.1.7. Use of Regeneration Vent Recovery System

The TEG dehydration unit regeneration vent stream once condensed can be compressed, cooled and used as fuel. Theslighter compounds in the stream prior to entering the reboiler. These off-gases are recycled back into the plant as fuel, instead of venting to the atmosphere or routing to a control device. This reduces purchased fuel and

11.4.2. Step 2 – Eliminate Technically Infeasible Options

All control options identified in Step 1 are technically feasible.

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

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

Rank	Control Technology	Estimated CO_2e Reduction	Reduction Details	Reference
1	Use of Regeneration Vent Recovery System	100%	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.)*
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 5.1.1.5 Improved Maintenance
3	Condenser	< 0.25%	Reduction of CH_4 in dehydrator waste gas.	Vendor Data
4	Use of Tank Flash Gas Recovery Systems	< 0.25%	Reduction of CH_4 in flash gas only.	Hard piped back into the system
5	Thermal Oxidizer	--	Reduction in CH_4. Increase in CO_2 due to waste gas combustion.	Vendor Data
6	Flare	--	Reduction in CH_4. Increase in CO_2 due	http://www.tceq.texas.gov/permitting/air/guidance/newsourcereview/flares/ and vendor

Rank	Control Technology	Estimated CO_2e Reduction	Reduction Details	Reference
			to waste gas and pilot gas combustion.	data

11.4.4. Step 4 – Evaluate Most Effective Control Options

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

11.4.4.1. Carbon Capture and Sequestration

Information on CCS is included in Section 11.2.4.

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

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

- Use of Regeneration Vent Recovery System;
- Proper Design and Operation;
- Use of Tank Flash Gas Recovery Systems; and
- Use of a Condenser.

11.5. REGENERATIVE THERMAL OXIDIZER

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

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

The RTO is an example of a control device in which the control of certain pollutants causes the formation of collateral GHG emissions. Specifically, the control of CH_4 in the process gas at the RTO results in the creation of additional CO_2 emissions via the combustion reaction mechanism. However, given the relative GWPs of CO_2 and CH_4 and the destruction of VOCs and HAPs, it is appropriate to apply combustion controls to CH_4 emissions even though it will form additional CO_2 emissions.[44]

[44] 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

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

Summary of GHG Hourly Emissions

GHG Pollutants	Hourly Emissions (lb/hr)												
GHG Pollutants	**RTO-5 Regenerative Thermal Oxidizer Emissions (RTO-5)**	**RTO Startup Emissions (RTO5-MSS)**	**Amine Still Vent to Flare During RTO Downtime Emissions (FLR-5)**	**Hot Oil Heater (F5A)**	**Hot Oil Heater (F5B)**	**Fugitives (FUG-FRAC5)**	**Flare Pilot (FLR-5)**	**Controlled Maintenance Emissions (FLR-5)**	**Maintenance Emissions to Atmosphere (Maintenance)**	**Controlled Startup Emissions (FLR-5)**	**Controlled Shutdown Emissions (FLR-5)**	**Shutdown Emissions to Atmosphere (Shutdown)**	**Total [1]**
CO_2	2,531.83	233.78	2,532.34	16,884.46	16,884.46	2.35E-03	23.73	20,279.46	-	41,031.55	41,465.66	-	59,370.05
CH_4	2.76E-03	4.40E-03	1.38E-03	0.32	0.32	0.03	4.47E-04	1.57	3.17	3.47	3.26	7.42	7.42
N_2O	1.24E-04	4.40E-04	6.28E-03	0.03	0.03	-	4.47E-05	2.72E-04	-	6.28E-03	1.37E-03	-	0.07
CO_2e	2,531.93	234.01	2,534.31	16,901.02	16,901.02	0.53	23.75	20,312.49	66.66	41,106.42	41,534.48	155.85	59,439.06
lb CO_2/bbl [2]	--	--	--	4.06	4.06	--	--	--	--	--	--	--	8.11

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

Maximum hourly emissions are taken from the following operating scenarios:

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

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

Greenhouse Gas Limit	16,884.46 lb	day	24 hrs	=	4.06 lb CO2
	hr	100,000 bbl	day		bbl

Summary of GHG Annual Emissions

GHG Pollutants	Annual Emissions (tpy)												
GHG Pollutants	**RTO-5 Regenerative Thermal Oxidizer Emissions (RTO-5)**	**RTO Startup Emissions (RTO5-MSS)**	**Amine Still Vent to Flare During RTO Downtime Emissions (FLR-5)**	**Hot Oil Heater (F5A)**	**Hot Oil Heater (F5B)**	**Fugitives (FUG-FRAC5)**	**Flare Pilot (FLR-5)**	**Controlled Maintenance Emissions (FLR-5)**	**Maintenance Emissions to Atmosphere (Maintenance)**	**Controlled Startup Emissions (FLR-5)**	**Controlled Shutdown Emissions (FLR-5)**	**Shutdown Emissions to Atmosphere (Shutdown)**	**Total [1]**
CO_2	10,881.18	0.94	192.46	73,953.92	73,953.92	0.01	103.93	302.95	-	300.65	400.59	-	160,090.55
CH_4	0.01	1.76E-05	1.05E-04	1.39	1.39	0.11	1.96E-03	0.02	0.03	0.02	0.03	0.05	3.06
N_2O	5.43E-04	1.76E-06	4.78E-04	0.14	0.14	-	1.96E-04	6.17E-06	-	4.44E-05	1.88E-05	-	0.28
CO_2e	10,881.61	0.94	192.61	74,026.45	74,026.45	2.33	104.03	303.36	0.65	301.19	401.13	1.04	160,241.78

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

FLR-5 Emission Factors [1]

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

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

Start-up Emissions Summary

FIN	EPN	Source Name	Hourly Emissions (lb/hr) VOC [1]	Hourly Emissions (lb/hr) NO_x [2]	Hourly Emissions (lb/hr) CO [2]	Annual Emissions (tpy) VOC [1]	Annual Emissions (tpy) NO_x [3]	Annual Emissions (tpy) CO [3]
Startup	FLR-5	Startup Emissions to FLR-5	48.01	3.31	6.60	0.51	0.03	0.05

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

Hourly Emissions of NO_x (lb/hr) = $\frac{0.138\ \text{lb}}{\text{MMBtu}} \Big| \frac{8.89\ \text{MMBtu}}{\text{hr}}$ = 3.31 lb/hr

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

Gas Heating Rates [1]

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

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

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

Startup Parameters for Emissions to FLR-5

Unit ID	Description	Hours Per Event (hr/event)	Frequency per Year (event/yr)	ID (ft)	Height (ft)	Total Volume [1] (ft^3/event)	Total Volume Rate [2] (ft^3/hr)	Vapor Density (lb/ft^3)	Vapor Mass Fraction [3] C1	C2	C3	iC4	C4	iC5	C5	C6	C7+	Gas Heating Rate [4] (MMBtu/hr)
TEG Dehydration Unit																		
TEG-2	TEG Flash Gas Vent and Still Vent	3	1			5,637	1,879											3.26
Amine Unit																		
AU-4	Amine Flash Gas and Still Vents	2	4			46,158	23,079											0.56
Pressure Vessels																		
31-358-1 Deeth	DC2	12	1	16	126	28,551	2,379	3.35	0.0323	0.7766	0.1329	0.0269	0.0199	0.0053	0.0033	0.0004	0.0025	4.42
30-358-1	DC2 Reflux Accum	12	1	10	50	4,712	393	7.72	0.0203	0.9699	0.0098	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.66
30-358-4	C2 Comp suct scrub	6	1	7	10	548	91	7.72	0.0203	0.9699	0.0098	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.15
30-358-6	Refrig comp suct scrub	6	1	8	10	905	151	1.50	0.0000	0.1297	0.8584	0.0109	0.0010	0.0000	0.0000	0.0000	0.0000	0.35
30-358-7	Refrig Accumulator	12	1	8	24	1,608	134	1.50	0.0000	0.1297	0.8584	0.0109	0.0010	0.0000	0.0000	0.0000	0.0000	0.31
31-358-4	DC3	12	1	13	114	16,857	1,405	0.83	0.0000	0.1079	0.6462	0.0800	0.1290	0.0183	0.0122	0.0009	0.0055	3.54
30-358-9	DC3 Reflux Accum	12	1	10	40	3,927	327	1.50	0.0000	0.1297	0.8584	0.0109	0.0010	0.0000	0.0000	0.0000	0.0000	0.75
30-358-401A/B	C3 COS Reactors	6	1	6	30	1,018	170	1.50	0.0000	0.1297	0.8584	0.0109	0.0010	0.0000	0.0000	0.0000	0.0000	0.39
30-358-402A/B	C3 H2S Reactors	6	1	7	34	1,578	263	1.50	0.0000	0.1297	0.8584	0.0109	0.0010	0.0000	0.0000	0.0000	0.0000	0.61
31-358-5	DC4	12	1	10	98	7,620	635	0.33	0.0000	0.0000	0.0069	0.3097	0.5389	0.0728	0.0480	0.0034	0.0203	2.04
30-358-10	DC4 Reflux accum	12	1	9	30	2,185	182	0.46	0.0000	0.0000	0.0079	0.3612	0.6294	0.0014	0.0000	0.0000	0.0000	0.57
31-358-6	C4 Splitter	12	1	12	212	25,334	2,111	0.46	0.0000	0.0000	0.0079	0.3612	0.6294	0.0014	0.0000	0.0000	0.0000	6.57
30-358-11	C4 Splitter comp K.O.	12	1	7	16	747	62	0.59	0.0000	0.0000	0.0225	0.9647	0.0128	0.0000	0.0000	0.0000	0.0000	0.19
30-358-12	C4 Splitter Reflux accum	12	1	9	40	2,752	229	0.46	0.0000	0.0000	0.0225	0.9647	0.0128	0.0000	0.0000	0.0000	0.0000	0.71
30-358-501A/B/C	Gasoline treaters	6	1	8	16	3,619	603	0.12	0.0000	0.0000	0.0000	0.0003	0.0230	0.4936	0.3272	0.0221	0.1338	2.30
30-358-502A/B/C	Caustic separators	6	1	6	20	2,205	368	0.12	0.0000	0.0000	0.0000	0.0003	0.0230	0.4936	0.3272	0.0221	0.1338	1.40
30-358-601A/B	Caustic Contactors	6	1	12	50	14,024	2,337	0.12	0.0000	0.0000	0.0000	0.0003	0.0230	0.4936	0.3272	0.0221	0.1338	8.89
30-358-602A/B	Caustic Settlers	6	1	6	30	2,036	339	0.12	0.0000	0.0000	0.0000	0.0003	0.0230	0.4936	0.3272	0.0221	0.1338	1.29
Pipelines																		
	RP	6	1	1	3,800	2,487	415	3.35	0.0323	0.7766	0.1329	0.0269	0.0199	0.0053	0.0033	0.0004	0.0025	0.77
	C2	6	1	1	3,800	2,487	415	7.72	0.0203	0.9699	0.0098	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.70
	C3	6	1	1	3,800	1,990	332	1.50	0.0000	0.1297	0.8584	0.0109	0.0010	0.0000	0.0000	0.0000	0.0000	0.76
	iC4	6	1	1	3,800	1,492	249	0.59	0.0000	0.0000	0.0225	0.9647	0.0128	0.0000	0.0000	0.0000	0.0000	0.77
	nC4	6	1	1	3,800	1,492	249	0.40	0.0000	0.0000	0.0000	0.0401	0.9576	0.0021	0.0001	0.0000	0.0000	0.78
	C5+	6	1	1	3,800	1,492	249	0.12	0.0000	0.0000	0.0000	0.0003	0.0230	0.4936	0.3272	0.0221	0.1338	0.95
Compressors																		
11-358-1A/B	Ethane	1	1	-	-	2,000	2,000	7.72	0.0203	0.9699	0.0098	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	3.38
11-358-2A/B	Refrigeration	2	1	-	-	1,200	600	1.50	0.0000	0.1297	0.8584	0.0109	0.0010	0.0000	0.0000	0.0000	0.0000	1.38
11-358-3	C4 Splitter	2	1	-	-	1,000	500	0.59	0.0000	0.0000	0.0225	0.9647	0.0128	0.0000	0.0000	0.0000	0.0000	1.54

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

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

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

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

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

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

[5] TEG-2 data taken from GRI-GLYCalc 4.0

Startup Emissions to FLR-5

			Controlled Weight Per Hour (lb/hr) [1]									Controlled Weight Per Year (lb/yr) [2]								
Unit ID	**Description**	**Emission Groups**	**C1**	**C2**	**C3**	**iC4**	**C4**	**iC5**	**C5**	**C6**	**C7**	**C1**	**C2**	**C3**	**iC4**	**C4**	**iC5**	**C5**	**C6**	**C7**
TEG Dehydration Unit																				
TEG-2	TEG Flash Gas Vent and Still Vent	A	5.53E-03	1.41	0.04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.02	4.24	0.11	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Amine Unit																				
AU-4	Amine Flash Gas and Still Vents	A	0.14	24.65	0.33	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.11	197.20	2.63	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Pressure Vessels																				
31-358-1 Deeth	DC2	A	2.57	61.80	10.58	4.29	3.16	0.84	0.52	0.07	0.40	30.83	741.64	126.92	51.47	37.92	10.05	6.23	0.79	4.80
30-358-1	DC2 Reflux Accum	A	0.62	29.40	0.30	1.60E-05	3.68E-07	3.68E-07	3.68E-07	5.22E-08	3.16E-07	7.39	352.79	3.57	1.92E-04	4.41E-06	4.41E-06	4.41E-06	6.27E-07	3.79E-06
30-358-4	C2 Comp suct scrub	A	0.14	6.83	0.07	3.71E-06	8.55E-08	8.55E-08	8.55E-08	1.21E-08	7.33E-08	0.86	40.99	0.41	2.23E-05	5.13E-07	5.13E-07	5.13E-07	7.28E-08	4.40E-07
30-358-6	Refrig comp suct scrub	B	1.61E-08	0.29	1.94	0.05	4.51E-03	7.45E-08	7.45E-08	1.06E-08	6.40E-08	9.65E-08	1.75	11.61	0.29	0.03	4.47E-07	4.47E-07	6.35E-08	3.84E-07
30-358-7	Refrig Accumulator	B	1.43E-08	0.26	1.72	0.04	4.01E-03	6.63E-08	6.63E-08	9.41E-09	5.68E-08	1.72E-07	3.12	20.64	0.52	0.05	7.95E-07	7.95E-07	1.13E-07	6.82E-07
31-358-4	DC3	C	7.97E-08	1.26	7.55	1.87	3.02	0.43	0.29	0.02	0.13	9.57E-07	15.13	90.65	22.44	36.20	5.12	3.43	0.26	1.55
30-358-9	DC3 Reflux Accum	C	3.49E-08	0.63	4.20	0.11	9.80E-03	1.62E-07	1.62E-07	2.30E-08	1.39E-07	4.19E-07	7.61	50.40	1.28	0.12	1.94E-06	1.94E-06	2.76E-07	1.67E-06
30-358-401A/B	C3 COS Reactors	D	1.81E-08	0.33	2.18	0.06	5.08E-03	8.39E-08	8.39E-08	1.19E-08	7.19E-08	1.09E-07	1.97	13.06	0.33	0.03	5.03E-07	5.03E-07	7.14E-08	4.32E-07
30-358-402A/B	C3 H2S Reactors	D	2.80E-08	0.51	3.37	0.09	7.87E-03	1.30E-07	1.30E-07	1.85E-08	1.12E-07	1.68E-07	3.06	20.25	0.51	0.05	7.80E-07	7.80E-07	1.11E-07	6.69E-07
31-358-5	DC4	E	6.94E-25	1.62E-09	0.01	1.28	2.23	0.30	0.20	0.01	0.08	8.33E-24	1.95E-08	0.17	15.34	26.70	3.61	2.38	0.17	1.00
30-358-10	DC4 Reflux accum	E	3.02E-25	3.02E-25	6.56E-03	0.60	1.04	2.32E-03	7.66E-05	5.84E-12	3.53E-11	3.62E-24	3.62E-24	0.08	7.19	12.53	0.03	9.19E-04	7.00E-11	4.23E-10
31-358-6	C4 Splitter	E	3.50E-24	3.50E-24	0.08	6.95	12.11	0.03	8.88E-04	6.77E-11	4.09E-10	4.20E-23	4.20E-23	0.91	83.38	145.30	0.32	0.01	8.12E-10	4.91E-09
30-358-11	C4 Splitter comp K.O.	E	1.35E-25	1.35E-25	8.31E-03	0.71	9.46E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.61E-24	1.61E-24	0.10	8.55	0.11	0.00E+00	0.00E+00	0.00E+00	0.00E+00
30-358-12	C4 Splitter Reflux accum	E	3.81E-25	3.81E-25	0.02	2.02	0.03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.57E-24	4.57E-24	0.28	24.19	0.32	0.00E+00	0.00E+00	0.00E+00	0.00E+00
30-358-501A/B/C	Gasoline treaters	E	0.00E+00	1.98E-24	6.14E-11	3.78E-04	0.03	0.71	0.47	0.03	0.19	0.00E+00	1.19E-23	3.68E-10	2.27E-03	0.20	4.24	2.81	0.19	1.15
30-358-502A/B/C	Caustic separators	E	0.00E+00	1.21E-24	3.74E-11	2.30E-04	0.02	0.43	0.29	0.02	0.12	0.00E+00	7.24E-24	2.24E-10	1.38E-03	0.12	2.58	1.71	0.12	0.70
30-358-601A/B	Caustic Contactors	E	0.00E+00	7.68E-24	2.38E-10	1.46E-03	0.13	2.74	1.82	0.12	0.74	0.00E+00	4.61E-23	1.43E-09	8.79E-03	0.76	16.43	10.89	0.74	4.45
30-358-602A/B	Caustic Settlers	E	0.00E+00	1.11E-24	3.45E-11	2.13E-04	0.02	0.40	0.26	0.02	0.11	0.00E+00	6.69E-24	2.07E-10	1.28E-03	0.11	2.39	1.58	0.11	0.65
Pipelines																				
	RP	-	0.45	10.77	1.84	0.75	0.55	0.15	0.09	0.01	0.07	2.69	64.60	11.06	4.48	3.30	0.88	0.54	0.07	0.42
	C2	-	0.65	31.03	0.31	1.69E-05	3.88E-07	3.88E-07	3.88E-07	5.51E-08	3.33E-07	3.90	186.19	1.88	1.01E-04	2.33E-06	2.33E-06	2.33E-06	3.31E-07	2.00E-06
	C3	-	3.54E-08	0.64	4.26	0.11	9.93E-03	1.64E-07	1.64E-07	2.33E-08	1.41E-07	2.12E-07	3.86	25.53	0.65	0.06	9.83E-07	9.83E-07	1.40E-07	8.44E-07
	iC4	-	5.38E-25	5.38E-25	0.03	2.85	0.04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.23E-24	3.23E-24	0.20	17.10	0.23	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	nC4	-	0.00E+00	0.00E+00	0.00E+00	0.08	1.92	4.22E-03	2.01E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.48	11.55	0.03	1.21E-03	0.00E+00	0.00E+00
	C5+	-	0.00E+00	8.17E-25	2.53E-11	1.56E-04	0.01	0.29	0.19	0.01	0.08	0.00E+00	4.90E-24	1.52E-10	9.35E-04	0.08	1.75	1.16	0.08	0.47
Compressors																				
11-358-1A/B	Ethane	-	3.14	149.73	1.52	8.14E-05	1.87E-06	1.87E-06	1.87E-06	2.66E-07	1.61E-06	3.14	149.73	1.52	8.14E-05	1.87E-06	1.87E-06	1.87E-06	2.66E-07	1.61E-06
11-358-2A/B	Refrigeration	-	6.40E-08	1.16	7.70	0.20	0.02	2.97E-07	2.97E-07	4.21E-08	2.54E-07	1.28E-07	2.33	15.40	0.39	0.04	5.93E-07	5.93E-07	8.42E-08	5.09E-07
11-358-3	C4 Splitter	-	1.08E-24	1.08E-24	0.07	5.73	0.08	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.16E-24	2.16E-24	0.13	11.46	0.15	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Emissions [3]			3.47	149.73	11.75	11.56	15.61	4.60	3.03	0.21	1.24	49.93	1,776.21	397.53	250.10	275.96	47.42	30.75	2.51	15.19

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

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

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

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

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

GHG Emissions

Input Data		
Maximum Hourly Release to Flare [1] =	23,079.17	scf/hr
Annual Releases to Flare [1] =	326,135.97	scf/yr
Higher Heating Value for N_2O [2] =	1.235E-03	MMBtu/scf

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

Global Warming Potentials [1]

CO_2	CH_4	N_2O
1	21	310

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

N_2O Emissions

Emission Factor[1,2]		N_2O Emissions[3,4]	
(kg/MMBtu)	(lb/MMBtu)	(lb/hr)	(tpy)
1.00E-04	2.20E-04	6.28E-03	4.44E-05

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

Example N_2O Hourly Emissions (lb/hr) = $\frac{23{,}079.17 \text{ scf}}{\text{hr}} \times \frac{1.235\text{E-03 MMBtu}}{\text{scf}} \times \frac{2.20\text{E-04 lb}}{\text{MMBtu}}$ = 6.28E-03 lb/hr

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

Example N_2O Annual Emission Rate (tpy) = $\frac{326{,}135.97 \text{ scf}}{\text{yr}} \times \frac{1.235\text{E-03 MMBtu}}{\text{scf}} \times \frac{2.20\text{E-04 lb}}{\text{MMBtu}} \times \frac{1 \text{ ton}}{2{,}000 \text{ lb}}$ = 4.44E-05 tpy

Speciated GHG Emissions - FLR-5

Gas Stream	Compound	Number of Carbon Atoms	DRE [1] (%)	Inlet to Flare [2] (lb/hr)	Inlet to Flare [2] (tpy)	Controlled GHG Emissions[3,4] (lb/hr)	Controlled GHG Emissions[3,4] (tpy)	Converted to CO_2 [5,6] (lb/hr)	Converted to CO_2 [5,6] (tpy)
Emissions to FLR-5	Methane	1	99%	347.25	2.50	3.47	0.02	343.78	2.47
	Ethane	2	99%	14,972.69	88.81	--	--	29,645.93	175.84
	Propane	3	99%	1,175.37	19.88	--	--	3,490.85	59.03
	Butanes	4	98%	1,358.50	13.15	--	--	5,325.33	51.55
	Pentanes +	5	98%	454.22	2.40	--	--	2,225.67	11.75

FLR-5 GHG Emissions [7]	(lb/hr)	(tpy)
CO_2	41,031.55	300.65
CH_4	3.47	0.02
N_2O	6.28E-03	4.44E-05
CO_2e	41,106.42	301.19

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

Example Controlled Methane Hourly Emission Rate (lb/hr) = $\frac{347.25 \text{ lb}}{\text{hr}} \times \frac{(100 - 99\%)}{100}$ = 3.47 lb/hr

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

Example Controlled Methane Annual Emission Rate (tpy) = $\frac{2.50 \text{ ton}}{\text{yr}} \times \frac{(100 - 99\%)}{100}$ = 0.02 tpy

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

Example Converted Methane Hourly Emission Rate (lb/hr) = $\frac{347.25 \text{ lb}}{\text{hr}} \times \frac{99\ \%}{100} \times 1$ = 343.78 lb/hr

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

Example Converted Methane Annual Emission Rate (tpy) = $\frac{2.50 \text{ ton}}{\text{yr}} \times \frac{99\ \%}{100} \times 1$ = 2.47 tpy

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

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{41{,}031.55 \text{ lb}}{\text{hr}} \times 1 + \frac{3.47 \text{ lb}}{\text{hr}} \times 21 + \frac{6.28\text{E-03 lb}}{\text{hr}} \times 310$ = 41,106.42 lb/hr

Targa Midstream Services LLC - Mont Belvieu Plant
Amine Still Vent Emissions During Scheduled RTO Downtime
FIN AU-4 EPN FLR-5

FLR-5 Emission Factors [1]

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

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

Speciated Gas Heating Rate

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

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

Gas Heating Rate of Methane in the Acid Gas (MMBtu/hr) = $\frac{2571.91 \text{ lb}}{\text{hr}} \times \frac{0.01\%}{100} \times 23{,}900 \text{ Btu} \times \frac{1 \text{ MMBtu}}{1{,}000{,}000 \text{ Btu}}$ = 0.0033 MMBtu/hr

Parameter	Units	Acid Gas
Gas Volume Flow Rate [1]	MMscf/day	0.55
Gas Mass Flow Rate [1]	lb/hr	2,571.91
Scheduled RTO Downtime Duration	hr/event	38
Scheduled RTO Downtime Frequency	events/yr	4
Annual Scheduled RTO Downtime	hr/yr	152
Flare Destruction Efficiency for C1-C3 [2]	%	99
Flare Destruction Efficiency for C4+ [2]	%	98

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

Amine Unit Outlet Streams

Speciated Gas	Speciated Acid Gas Percentage[1] (%)
Carbon Dioxide	96.52
Methane	5.37E-03
Ethane	0.96
Propane	0.01
Ucarsol AP-810	5.65E-05
H_2S	100.00
Total VOC Content (%)	0.01

[1] Based on similar operations at the facility.

Targa Midstream Services LLC - Mont Belvieu Plant
Amine Still Vent Emissions During Scheduled RTO Downtime
Controlled Acid Gas Emissions During Scheduled RTO Downtime [1, 2, 3]

Component	Inlet to Flare (lb/hr)	Destruction Efficiency (%)	Controlled Hourly Emissions (lb/hr)	Controlled Annual Emissions (tpy)
Carbon Dioxide	2482.41	0%	2,482.41	188.66
Methane	0.14	99%	1.38E-03	1.05E-04
Ethane	24.65	99%	0.25	0.02
Propane	0.33	99%	3.29E-03	2.50E-04
Ucarsol AP-810	1.45E-03	98%	2.90E-05	2.21E-06
Total VOC Emissions	0.33	1.97	3.32E-03	2.52E-04

[1] Emissions based on similar operations at the facility.

[2] Inlet to Flare (lb/hr) = Gas Mass Flow Rate (lb/hr) x VOC Component Content (%)/100

Inlet to Flare of Propane (lb/hr) = $\frac{2,571.91 \text{ lb}}{\text{hr}} \; \frac{0.0128}{100}$ = 0.33 lb/hr

[3] Controlled Hourly Emissions of VOC (lb/hr) = Inlet to Flare (lb/hr) x Destruction Efficiency (%) / 100

Hourly Emissions of Propane (tpy) = $\frac{0.33 \text{ lb}}{\text{hr}} \; \frac{99 \%}{100}$ = 3.29E-03 lb/hr

[4] Controlled Annual Emissions of VOC (tpy) = Hourly Emissions (lb/hr) x Annual Scheduled RTO Downtime Hours (hr/yr) / 2,000 lb/ton

Annual Emissions of Propane (tpy) = $\frac{3.29\text{E-03 lb}}{\text{hr}} \; \frac{152 \text{ hr}}{\text{yr}} \; \frac{\text{ton}}{2,000 \text{ lb}}$ = 2.21E-06 tpy

FLR-5 Combustion Emissions from AU-4

FIN	EPN	Source Name	Gas Stream	Hourly Emissions (lb/hr) NO_x [1]	CO [1]	VOC [2]	SO_2 [3,4,6,8]	H_2S [3,4,5,6,7]	Annual Emissions (tpy) NO_x	CO	VOC	SO_2	H_2S
AU-4	FLR-5	Amine Unit	Acid Gas	0.04	0.31	3.32E-03	0.09	9.32E-04	2.74E-03	0.02	2.52E-04	6.53E-03	7.09E-05
			Total	0.04	0.31	3.32E-03	0.09	9.32E-04	2.74E-03	0.02	2.52E-04	6.53E-03	7.09E-05

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

NO_X Hourly Emissions (lb/hr) = $\frac{0.0641 \text{ lb}}{\text{MMBtu}} \; \frac{0.56 \text{ MMBtu}}{\text{hr}}$ = 0.04 lb/hr

[2] VOC emissions estimated above.

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

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

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

[6] The uncontrolled H_2S concentration at the inlet is 0.030 ppmw

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

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

[8] Hourly Emissions of SO_2 (lb/hr) = 2 * (Flare Destruction Efficiency (%) / 100)) * (H2S Emission Factor (ppmw) / 1,000,000) * Volume Flow Rate (barrels/day) * 42 (gal/barrel) * Specific Gravity * Molecular Weight Ratio of SO_2/H_2S * 1 / 24 (day/hr)

Hourly Emissions of SO_2 (lb/hr) = $2 \; \frac{98\%}{100} \; \frac{0.03 \text{ parts H2S}}{1,000,000} \; \frac{110,000 \text{ barrels}}{\text{day}} \; \frac{42 \text{ gal}}{\text{barrel}} \; 0.484 \; 1.88 \; \frac{1 \text{ day}}{24 \text{ hr}}$ = 8.59E-02 lb/hr

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

Input Data		
Maximum Amine Acid Gas Flowrate =	2,571.91	lb/hr
	0.55	MMscf/day
Hours of Operation =	152	hrs/yr
Higher Heating Value for N_2O [1] =	1.235E-03	MMBtu/scf

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

Amine Unit Outlet Streams

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

[1] Based on similar operations at the facility.

Global Warming Potentials [1]

CO_2	CH_4	N_2O
1	21	310

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

N_2O Emissions from Acid Gas Stream

Compound	Emission Factor[1,2]		N_2O Emissions[3,4]	
	(kg/MMBtu)	(lb/MMBtu)	(lb/hr)	(tpy)
N_2O	0.0001	0.00022046	6.284E-03	4.776E-04

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

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

[3] Hourly Emission Rate for N_2O (lb/hr) = Waste Gas Flowrate (MMscf/day) x (day / 24 hr) x (10^6 scf / 1 MMscf) x Subpart W Process Gas HHV (MMBtu/scf) x Emission Factor (kg/MMBtu) x (2.2046 lb/kg)

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

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

Example N_2O Annual Emission Rate (tpy) = $\frac{6.28\text{E-03 lb}}{\text{hr}} \times \frac{152\ \text{hr}}{\text{yr}} \times \frac{1\ \text{ton}}{2{,}000\ \text{lb}}$ = 4.78E-04 tpy

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

Gas Stream	Compound	Number of Carbon Atoms	DRE [1] (%)	Inlet to Flare (lb/hr)	Controlled GHG Emissions[3,4] (lb/hr)	Controlled GHG Emissions[3,4] (tpy)	Converted to CO2 (lb/hr)	Converted to CO2 (tpy)
Acid Gas	Carbon Dioxide	1	0%	2,482.41	2482.41	188.66	--	--
	Methane	1	99%	0.14	1.38E-03	1.05E-04	0.14	1.04E-02
	Ethane	2	99%	24.65	--	--	48.81	3.71E+00
	Propane	3	99%	0.33	#REF!	#REF!	0.98	7.43E-02
	Ucarsol AP-810	5	98%	0.001	--	--	0.01	5.41E-04

Total GHG Emissions [7]		
Compound	**(lb/hr)**	**(tpy)**
CO_2	2,532.34	192.46
CH_4	1.38E-03	1.05E-04
N_2O	6.28E-03	4.78E-04
CO_2e	2,534.31	192.61

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

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

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

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

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

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

Example Controlled Methane Annual Emission Rate (tpy) = $\frac{1.38\text{E-}03 \text{ lb}}{\text{hr}} \times \frac{152 \text{ hr}}{\text{yr}} \times \frac{1 \text{ ton}}{2{,}000 \text{ lb}}$ = 1.05E-04 tpy

[5] Per 40 CFR Part 98.233(z) (Subpart W), for fuel combustion units that combust process vent gas, the following equation is used to estimate the GHG emissions from additional carbon compounds in the fuel.
Hourly Emission Rate for Compounds Converted to CO2 (lb/hr) = Inlet to Flare (lb/hr) x DRE (%)/100 x Carbon Count (#)

Example Converted Methane Hourly Emission Rate (lb/hr) = $\frac{0.14 \text{ lb}}{\text{hr}} \times \frac{99\%}{100} \times 1$ = 0.137 lb/hr

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

Example Converted Methane Annual Emission Rate (tpy) = $\frac{0.14 \text{ lb}}{\text{hr}} \times \frac{152 \text{ hr}}{\text{yr}} \times \frac{1 \text{ ton}}{2{,}000 \text{ lb}}$ = 0.01 tpy

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

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{2532.34}{\text{hr}} \times 1 + \frac{0.0014}{\text{hr}} \times 21 + \frac{6.28\text{E-}03}{\text{hr}} \times 310$ = 2,534.31 lb/hr

MSS Calculations – Number of events per year

Liquid Parameters

Unit ID	Description	Hours Per Event (hr/event)	Frequency per Year (event/yr)
Filters/Coalescers			
15-358-1A/B	Plant inlet feed filters	2	104
15-358-2A/B	Plant feed inlet coalescers	2	104
15-358-401	Treated Propane Filter Coalescer	2	104
15-358-501	Treated gasoline coalescer	2	104
15-358-601	n-butane product coalescer	2	104
Pumps			
28-358-1A/B	DC2 Reflux Pumps	2	2
28-358-2A/B	DC3 Reflux Pumps	2	2
28-358-3A/B	C3 Inject pumps	2	2
28-358-4A/B	DC4 Reflux pumps	2	2
28-358-5A/B	Gasoline booster pumps	2	2
28-358-6A/B	Gasoline injection pumps	2	2
28-358-7A/B	C4 split bottoms pumps	2	2
28-358-8A/B	C4 split reflux pumps	2	2
28-358-9A/B	C4 Split comp K.O. drum pumps	2	2
28-358-10A/B	iC4 injection pumps	2	2
28-358-11A/B	nC4 injection pumps	2	2

Filters/Coalescers

Filter coalescer emissions calculations are based upon an estimated two filter changes per week over 52 weeks or 104 filter changes annually with 4 hours required per each event.

Compressors

The ethane compressor emissions were based upon maintenance 3x per year on two compressors or 6 events total.

The refrigeration compressor emissions are based on 1x per year for two units.

The C4 splitter compressor maintenance is 2x per year.

Pumps

Pumps are typically serviced 1x per year.

MSS Process Equipment Clearing Procedure

The process that is followed for clearing equipment for maintenance is similar to the Vessel Clearing procedure for the Maintenance, Startup, and Shutdown (MSS) Update for Process Vessels from the TCEQ Guidance document.

From the document:

3. Steps to Clearing Vessels

A. Route fluids to other parts of process as much as possible.

B. Route fluids to knockout-drum for phase separation, if necessary. If VOC partial pressure > 0.5 psi, route any vents to control device or controlled recovery system.

C. Drain liquids to covered vessels if possible. Control loading emissions if vapor pressure > 0.5 psia. If physical configuration of the equipment prevents draining to a covered vessel, can drain to open pan but cover liquid or transfer liquid to covered vessel within one hour of being drained.

D. Generally, if liquid had vapor pressure ≥ 0.5 psia, degas vessel to control until VOC concentration < 10,000 ppmv.

Liquid Recovery and Clearing

Liquids are recovered from the process as much as possible to the lowest potential drain point from each vessel or piece of equipment. The remaining volume is shown in the calculations as the remaining liquid 'heel'. At this point the equipment is pressured with an inert gas, typically nitrogen, and blown to the flare line. Some of this liquid will be recaptured in knockout pots from the flare system, but here it is conservatively estimated as total flared pounds.

Liquid Parameters

Unit ID	Description	Hours Per Event (hr/event)	Frequency per Year (event/yr)	Heel (ft)	Heel Volume [3] (ft^3/event)
Filters/Coalescers					
15-358-1A/B	Plant inlet feed filters	2	104	0.5	4
15-358-2A/B	Plant feed inlet coalescers	2	104	0.5	10
15-358-401	Treated Propane Filter Coalescer	2	104	0.5	4
15-358-501	Treated gasoline coalescer	2	104	0.5	2
15-358-601	n-butane product coalescer	2	104	0.5	4
Pumps					
28-358-1A/B	DC2 Reflux Pumps	2	2	-	-
28-358-2A/B	DC3 Reflux Pumps	2	2	-	-
28-358-3A/B	C3 Inject pumps	2	2	-	-
28-358-4A/B	DC4 Reflux pumps	2	2	-	-
28-358-5A/B	Gasoline booster pumps	2	2	-	-
28-358-6A/B	Gasoline injection pumps	2	2	-	-
28-358-7A/B	C4 split bottoms pumps	2	2	-	-
28-358-8A/B	C4 split reflux pumps	2	2	-	-
28-358-9A/B	C4 Split comp K.O. drum pumps	2	2	-	-
28-358-10A/B	iC4 injection pumps	2	2	-	-
28-358-11A/B	nC4 injection pumps	2	2	-	-

Equipment Degassing to Control and Opening

After the equipment has been emptied of liquids, it is re-pressurized using nitrogen and re-purged into the flare line. This process is repeated until the remaining vapor concentration is below 10,000 ppmvd as measured using either a calibrated Method 21 device or a specialized LEL monitor that can read inert atmospheres. At that point the equipment is vented to atmosphere.

Uncontrolled Emissions Sent to Atmosphere

Unit ID	Description	Uncontrolled Weight Per Hour (lb/hr) [1,2] C1	C2	C5
Filters/Coalescers				
15-358-1A/B	Plant inlet feed filters	0.1371	3.2967	0.0001
15-358-2A/B	Plant feed inlet coalescers	0.2757	6.6312	0.0003
15-358-401	Treated Propane Filter Coalescer	0.0000	0.5287	0.0000
15-358-501	Treated gasoline coalescer	0.0000	0.0000	0.0142
15-358-601	n-butane product coalescer	0.0000	0.0000	0.0000
Pumps		0.0000	0.0000	
28-358-1A/B	DC2 Reflux Pumps	0.0178	0.8510	0.0000
28-358-2A/B	DC3 Reflux Pumps	0.0000	0.1601	0.0000
28-358-3A/B	C3 Inject pumps	0.0000	0.1601	0.0000
28-358-4A/B	DC4 Reflux pumps	0.0000	0.0000	0.0000
28-358-5A/B	Gasoline booster pumps	0.0000	0.0000	0.0071
28-358-6A/B	Gasoline injection pumps	0.0000	0.0000	0.0071
28-358-7A/B	C4 split bottoms pumps	0.0000	0.0000	0.0000
28-358-8A/B	C4 split reflux pumps	0.0000	0.0000	0.0000
28-358-9A/B	C4 Split comp K.O. drum pumps	0.0000	0.0000	0.0000
28-358-10A/B	iC4 injection pumps	0.0000	0.0000	0.0000
28-358-11A/B	nC4 injection pumps	0.0000	0.0000	0.0000
Compressors		0.0000	0.0000	
11-358-1A/B	Ethane	3.1744	151.4714	0.0000
11-358-2A/B	Refrigeration	0.0000	8.5483	0.0000
11-358-3	C4 Splitter	0.0000	0.0000	0.0000
Emissions [4]		3.1744	151.4714	0.0142

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

Please note: No equipment is vented to atmosphere without first being degassed and vented to a control device.