2015 GHG Baseline Quantification
South American Conventional Oil & Gas Facilities
Gran Tierra Energy Inc.

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NOVUS PROJECT TEAM:

Engineer:	Reanna Zhang, P. Eng.
Scientist:	Laura Clark, B.Eng., E.I.T.
Project Manager:	Craig Vatcher, CET, B.Tech
Specialist:	Dr. Xin Qiu ACM, EP, P.Met.

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1.0 Introduction

Novus West Inc. (Novus) was retained by Gran Tierra Energy Inc. (GTE) to collect, summarize and quantify greenhouse gas (GHG) emissions for their assets located in Colombia and Brazil, based on 2015 GHG emissions. While no local regulatory drivers exist for the region, GTE is acting as a responsible producer by committing to following international standards for voluntary reporting of GHG emissions. The 2015 Baseline report presented here will establish base year emissions levels for GTE to use as a benchmark for future reporting years.

2.0 Operations

GTE started its operations in Colombia in June 2006, as result of the acquisition of Argosy Energy. In 2007, GTE Colombia discovered the Juanambu (5 MM barrel gross) and Costayaco fields (50 MM barrel gross) in the Putumayo basin. Costayaco field started production in August 2007. The Moqueta field was discovered in the Putumayo basin in 2010. Moqueta started production in June of 2011 after the pipeline was tied to Costayaco facilities. Currently GTE is the largest producer, reserve holder and exploration landholder in the Putumayo Basin of southern Colombia.

Figure 1: GTE Assets in Columbia

Columbia operated assets include crude processing facilities at Costayaco and Moqueta. These sites include eleven wells at Costayaco and eight wells at Moqueta. In 2015, average production

had grown to approximately 24,000 barrels of oil per day gross from the two oil production facilities at Costayaco and Moqueta.

In addition, GTE has Brazilian properties located in the Recôncavo Basin in the State of Bahia in Eastern Brazil. In 2015, the daily oil production was 1,133 barrels from two producing oil wells and the Tie Field processing facility.

3.0 Guidelines and Principles for Reporting

International guidance for greenhouse gas quantification and reporting is based on the Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions document (the Guideline), prepared by the International Petroleum Industry Environment Conservation Association (IPIECA).

3.1 Reporting Guidance

The report was developed according to the following guidelines and standards:

- Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions, second edition, International Petroleum Industry Environment Conservation Association (IPIECA), the American Petroleum Institute (API) and International Association of Oil and Gas Producers (OGP), May 2011;
- Compendium of Greenhouse Gas Emission Estimation Methodologies for Oil and Gas Industry, API, August 2009 (the Compendium);
- AP 42, Fifth Edition Compilation of Air Pollutant Emission Factors, US Environmental Protection Agency (EPA), January 1995 (AP-42); and,
- Update of Fugitive Equipment Leak Emission Factors, Canadian Association of Petroleum Producer (CAPP), February 2014 (CAPP).

3.2 Reporting Principles

The reporting principles are described below (IPIECA, 2011):

Relevance: Define boundaries that appropriately reflect the GHG emissions of the organizations and the decision-making needs of users.

Completeness: Account for all GHG emission sources and activities which are material within the chosen organizational and operational boundaries. Any specific exclusions should be stated and justified.

Consistency: Use consistent methodologies and measurements to allow meaningful comparison of emissions over time. The consistent application of boundary

definitions, accounting practices and calculation methodologies over time is essential for the production of comparable GHG emissions data. Transparently document any changes to the data, methods or any other factors in the time series.

Transparency: The degree of the information on the processes, procedures, assumptions and limitations of the GHG inventory are disclosed. Information should be reported in a clear, understandable, factual, neutral and coherent manner. Any changes to the data, methods or other factors affecting a time series of reported emissions should be transparently documented. The inventory process should be based on clear and complete documentation and archives.

Accuracy: Ensure that estimates of GHG emissions are systemically neither over nor under actual emission levels, as far as can be judged, and that uncertainties are quantified and reduced as far as practicable. Ensure that sufficient accuracy is achieved to enable users to make decisions with confidence as to the integrity of the reported GHG information.

4.0 Reporting Scope

4.1 Reporting Boundary

GTE's reporting boundary is intended to encompass the producing assets in both Colombia and Brazil. The boundary definition uses the control approach as outlined in the World Resources Institute WRI Greenhouse Gas Protocol, 2004. Under the control approach, a company accounts for 100 percent of the GHG emissions from operations over which it has control (WRI, 2004).

The Tie Field process plant and associated well pads in Brazil, and the Costayaco and Moqueta process facilities and well pads in Columbia constitute the 2015 GHG reporting boundary. Equipment located within the physical plant boundary but not operated by GTE are not included in the reporting boundary.

The Baseline emissions quantification has been performed in accordance with the reporting of Scope 1 emissions under the Guideline, which are defined as (IPIECA, 2011):

- combustion in stationary sources (e.g. fuel use in engines or turbines used to compress gases, pump liquids and generate electricity, and fuel use in heaters and boilers);
- combustion in flares and incinerators;
- combustion in mobile sources (e.g. transportation in motor vehicles and vessels, such as tank trucks and oil tankers);

- process emissions (e.g. glycol dehydration);
- venting emissions (e.g. vessel loading, tank storage and flashing, and venting of associated gas);
- fugitive emissions (e.g. leaks from equipment and piping components); and,
- non-routine events (e.g. gas releases during planned pipeline and equipment; and maintenance, releases from unplanned events).

Figure 2 outlines the reporting organizational and operational boundaries for GTE.

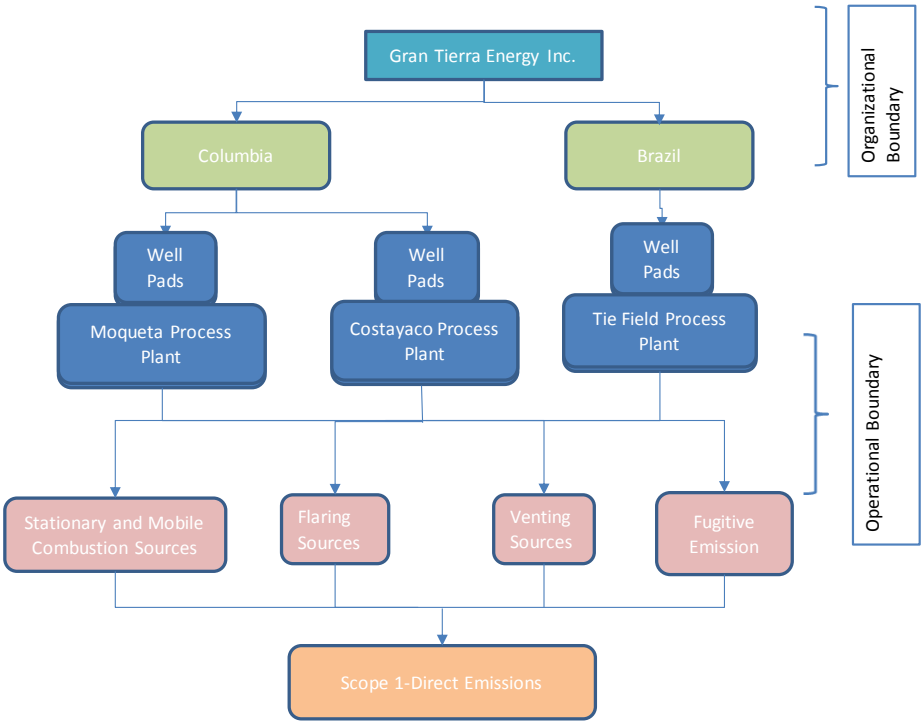

Figure 2: GTE Organizational and Operational Boundaries for 2015 Baseline Quantification

4.2 Reporting Period

The reporting period for Baseline GHG emissions is defined as January 1st through December 31st, 2015.

4.3 Types of GHG Emissions

Six classes of greenhouse gases (GHGs) were identified as being of concern within the Kyoto Protocol (UNFCC, 2008):

- Carbon dioxide (CO_2),
- Methane (CH_4),
- Nitrous Oxide (N_2O),
- Sulfur hexafluoride (SF_6),
- Perfluorocarbons (PFCs); and,
- Hydrofluorocarbons (HFCs).

The most prevalent GHGs emitted from oil and natural gas industry operations are CO_2, CH_4, and N_2O, due to the number of combustion sources. HFC's are increasingly used in refrigeration systems, including virtually all motor vehicle air conditioners. Both HFC's and PFC's may be used as solvents, while PFC's are used in some fire extinguishing systems. Sulphur hexafluoride is found in high-voltage electrical equipment, and it is sometimes used as a tracer in pipelines (IPIECA, 2011).

The report will evaluate the potential emissions of the above six classes of GHGs within the reporting boundary.

4.4 GHG Reporting Unit

In order to account for direct and indirect varying effects of different types of GHGs, the concept of Global Warming Potential (GWP) has been introduced. The GWP of a greenhouse gas is defined as the ratio of the time-integrated radiative forcing (warming effect) from the instantaneous release of 1 kg of the GHG relative to that from the release of 1 kg of CO_2. Global warming potential is calculated over different time periods, typically ranging from 20 to 500 years. The most common time period for expressing GWPs is 100 years. The 100-year GWPs for the six GHGs covered by the Kyoto Protocol come from *Climate Change 1995: The Science of Climate Change* (IPCC, 1996), which is commonly referred to as the Second Assessment Report (SAR). In 2007, the IPCC published *Climate Change 2007: The Physical Science Basis* (IPCC, 2007), referred to as the Fourth Assessment Report (AR4), which contains revised GWPs (API, 2009).

In the report, the second set of GWP values (CO_2 GWP=1, CH_4 GWP=25 and N_2O GWP=298) from AR4 are applied. GHG emissions are reported as tonnes CO_2-equivalent basis (CO_2e) which is an aggregation of the mass of emissions of each GHG multiplied by its corresponding GWP.

5.0 Plant Process and Emission Sources

5.1 Description and Process Diagram

Crude oil extracted from GTE's oil wellpads are sent to the facility separators where oil and gas are separated. After the separated gases go through the scrubber, the gases are used at site for fuel for the heaters and electricity generators. Surplus gas is sent to the flare stack to burn.

Liquids are sent to Separators for separation of water and oil. The separated oil is then sent to tanks for storage and ultimately off-site transport through pipelines and tankers. Tank vapours at Costayaco are collected through a loader and sent to the flare stack for destruction. The flare control efficiency is 99.98%, as the flare is out approximately 2-hours per year.

Figure 3 and **Figure 4** show the crude oil process at Costayaco and Moqueta respectively (no diagram was available for the Brazil Tie Field). There is an additional Separator located at Moqueta that is not shown in the figure.

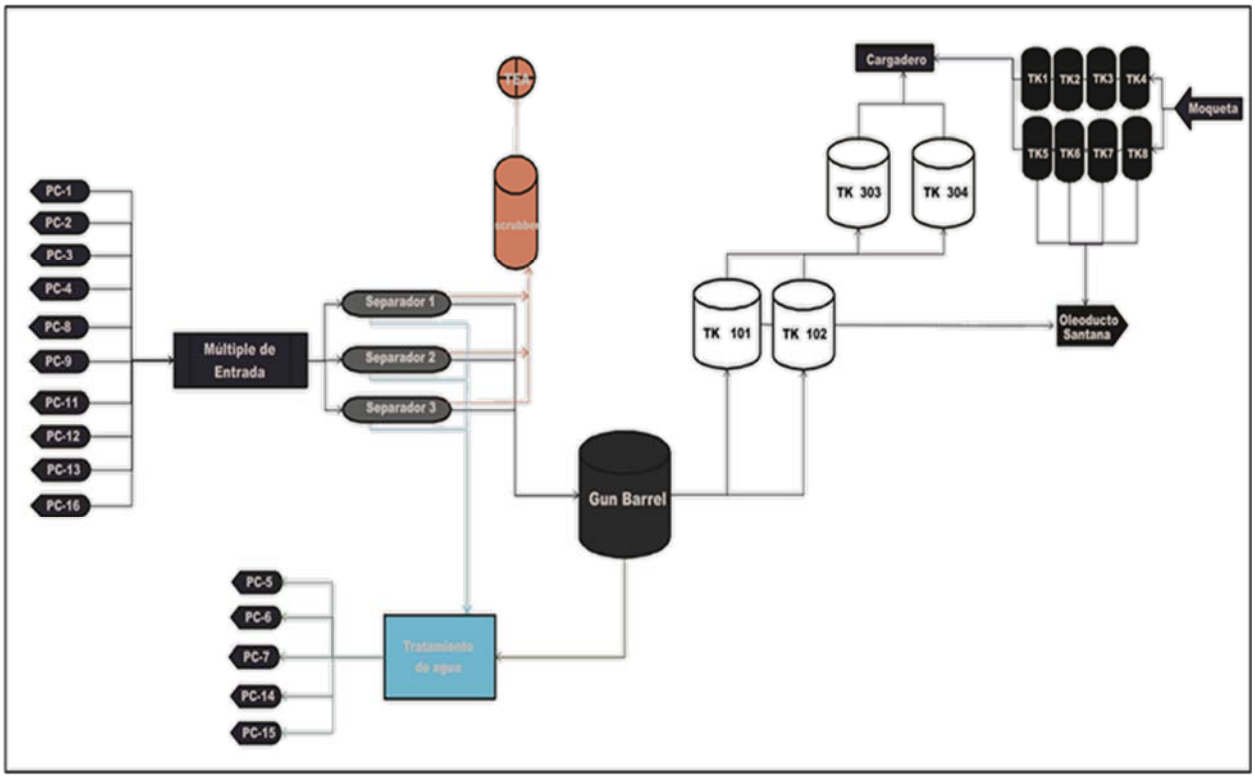

Figure 3: Costayaco Facility Process Flow Diagram

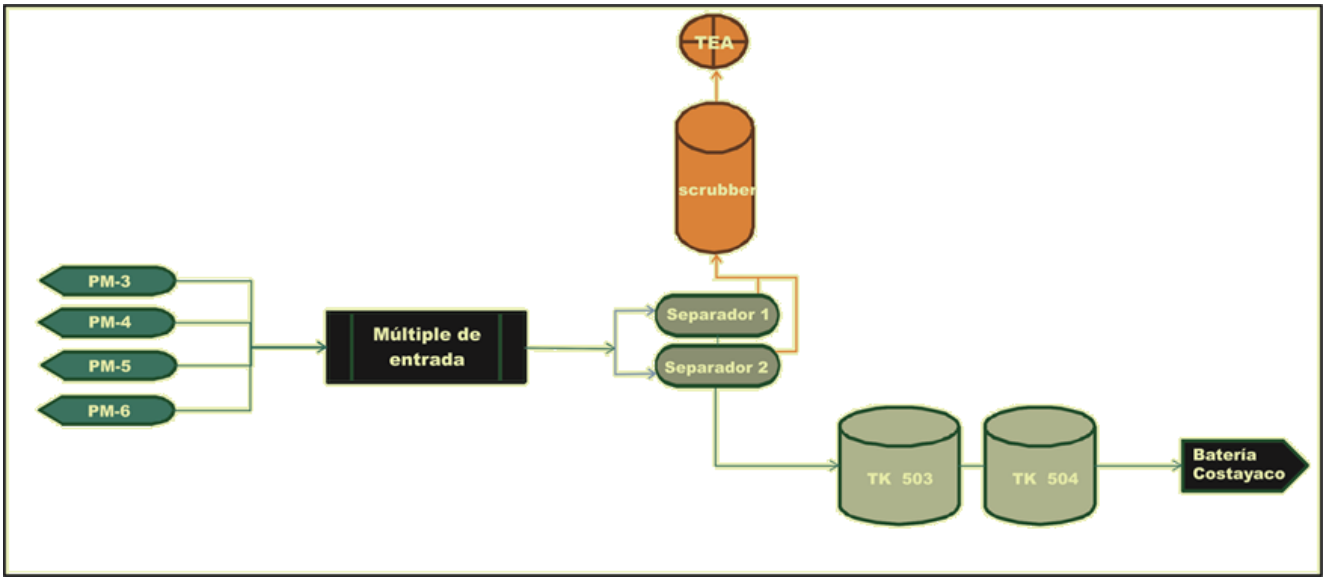

Figure 4: Moqueta Facility Process Flow Diagram

5.2 Emission Sources and Relative Characteristic GHGs

5.2.1 Combustion Emission Sources

Combustion of carbon-containing fuels in stationary equipment such as engines, burners, heaters, boilers, flares, and incinerators results in the formation of CO_2 due to the oxidation of carbon. Very small quantities of N_2O may be formed during fuel combustion by reaction of nitrogen and oxygen. CH_4 may also be released in exhaust gases as a result of incomplete fuel combustion.

Emissions resulting from the combustion of fuel in transportation equipment (i.e., vessels, barges, ships, railcars, and trucks) that are included in the inventory are categorized as mobile combustion sources.

Well exploration, drilling, testing and completions for all well pads were conducted by third-parties. All combustion equipment used for these activities were excluded for reporting. Crude oil transportation from well pads to the processing plants and processed oil transportation out of the plants are through third-party pipelines. Therefore, all emissions associated with operating these pipelines have been excluded.

For both Costayaco and Moqueta facilities, the gas-driven turbine generators are located within the facility's physical boundaries, but are owned and operated by a third-party. As a result, their emissions were excluded from 2015 total emission calculations under the Guideline's Scope 1 requirements (IPIECA, 2011).

5.2.2 Process Emissions and Vented Sources

Vented sources occur as releases resulting from normal operations, maintenance and turnaround activities, and emergency and other non-routine events. These include sources such as crude oil, condensate, oil, and gas product storage tanks; blanket fuel gas from produced water or chemical storage tanks; loading/ballasting/transit sources, and loading racks. CH_4 is often released from the hydrocarbon storage tanks. Depending on the product composition, CO_2 may be a component of the products and potentially released through process and venting sources.

The following maintenance, turnover, and non-routine operations did not occur at the facilities in 2015:

- mud degassing;
- low pressure gas well casing;
- gathering pipeline blowdowns;
- vessel blowdowns;
- emergency shutdown / emergency safety blowdown;
- pressure relief valves (PRV's) that were not diverted to-flare;
- well unloading and workovers; and,
- well blowouts (when not flared).

Only venting from tank flashing, tank storage and produced water tanks occurred at the facilities during 2015 operations.

5.2.3 Fugitive Emission Sources

Fugitive emissions are unintentional releases from piping components and equipment leaks at sealed surfaces, as well as from underground pipelines. Fugitive emissions are usually low volume leaks of process fluid (gas or liquid) from sealed surfaces, resulting from the wear of mechanical joints, seals, and rotating surfaces over time. Specific fugitive emission source types include components and fittings such as valves, flanges, pump seals, compressor seals, pressure relief valves (PRV's), or sampling connections. Fugitive emissions also include non-point evaporative sources such as from wastewater ponds, pits, and impoundments. Similar to venting sources, CH_4 and CO_2 are potential GHG's depending on the composition of the product.

Potential emissions of GHG's SF_6, PFC's and HFC's from oil production have not been identified as being emitted from the reporting facilities. The emission sources and GHG's associated with GTE sources are summarized in **Table 1**.

Table 1: Identified Emission Sources and GHGs at Gran Tierra Facilities

Facility	Emission Source	Emission Categories	GHGs
Tie Field (Brazil)	Heater/Treater	Combustion Source	CO_2, CH_4, N_2O
	Fire Pumps	Combustion Source	CO_2, CH_4, N_2O
	Internal Combustion Engines	Combustion Source	CO_2, CH_4, N_2O
	Flare	Combustion Source	CO_2, CH_4, N_2O
	Mobile	Combustion Source	CO_2, CH_4, N_2O
	Storage Tanks	Venting Source	CO_2, CH_4
	Leaks from Components and Process Lines	Fugitive Emission Source	CO_2, CH_4
Costayaco (Columbia)	Fire Pumps	Combustion Source	CO_2, CH_4, N_2O
	Internal Combustion Engines	Combustion Source	CO_2, CH_4, N_2O
	Turbine Generators	Combustion Source	CO_2, CH_4, N_2O
	Flares	Combustion Source	CO2, CH4, N_2O
	Crude Oil Storage Tanks	Venting Source	CO_2, CH_4
	Produced Water Tank	Venting Source	CH_4
	Leaks from Components and Process Lines	Fugitive Emission Source	CO_2, CH_4
Moqueta (Columbia)	Internal Combustion Engine	Combustion Source	CO_2, CH_4, N_2O
	Flares	Combustion Source	CO_2, CH_4, N_2O
	Storage Tanks	Venting Source	CO_2, CH_4
	Leaks from Components and Process Lines	Fugitive Emission Source	CO_2, CH_4

6.0 Quantification Methodology

Greenhouse gas emission quantification methods were referenced from the Compendium. When necessary, AP-42 emission factors or CAPP guidance were applied when more appropriate emission quantification approaches were available versus those presented in the Compendium.

A calculation spreadsheet was created to determine the emissions at the equipment level. The equipment emissions within the facility were summed according to the Guideline to determine facility level emissions. The corporate-level GHG emissions are an aggregate of all corporate owned facilities' emissions identified within the GHG quantification boundary. **Table 2** lists the methodologies used for each emission source, including the relative fuel/gas properties and compositions. A methodology report documents equations, constants, assumptions and emission factors used for calculation is provided in Appendix A.

Table 2: Quantification Methodologies Used for Quantification

Emission Source	Emission Categories	Calculation Methodology			Emission Factor Reference	Fuel Property Reference
		CO_2	CH_4	N_2O		
Diesel Fire Pumps	Combustion Source	EF based on fuel type	EF based on fuel type	EF based on fuel type	Compendium Tables 4-3 and 4-5	Compendium Table 3-8
Diesel Internal Combustion Engines	Combustion Source	EF based on fuel type	EF based on fuel type	EF based on fuel type	Compendium Tables 4-3 and 4-5	Compendium Table 3-8
Heater/Treater	Combustion Source	Mass balance and fuel carbon content	Equipment Specific EF	Equipment Specific EF	Compendium Tables 4-7	Brazil monthly gas analysis in pdf files
Turbine Generators	Combustion Source	Mass balance and fuel carbon content	Equipment Specific EF	Equipment Specific EF	Compendium Tables 4-9	Brazil monthly gas analysis in pdf files
Storage Tanks	Venting Source	Correlation equation: Vasquez-Beggs	Correlation equation: Vasquez-Beggs	N/A	Equations from Compendium	Moqueta MTQ-1 sample analysis
Leaks from Components and Process Lines	Fugitive Emission Source	Fugitive components and EFs	Fugitive components and EFs	N/A	CAPP Fugitive EF, February 2014	CAPP UOG Volume 3 Table 5

7.0 Fuel Data and Metric System

7.1 Tie Field

At Tie Field, flare gas volumes are metered continuously using Flow Boss meters. The heater burns the same gas as the flare stack and is not metered since it is a relatively small volume compared to the flared gas volumes. Therefore, heater fuel consumption was estimated. Diesel volumes for fire pump and engine were not directly available, so fuel consumption was estimated using output ratings and running hours of equipment. Mobile gasoline consumption was recorded using fuel purchase receipts.

The above fuel consumption, flared gas volumes and operational parameters for diesel equipment were manually input into the information collection spreadsheet tool for summarizing. Fuel consumptions used for Tie Field GHG emission calculations are summarized in **Table 3**.

Flare gas was sampled on a monthly basis and monthly flare gas component analyses were provided. The files are listed below according to the sampling month sequence. All gas

analysis was used for calculating average mole carbon content, mass carbon content, high heating value and fuel molecular weight parameters for the combustion equipment sources and flare stacks.

- RELATaRIO GRAN TIERRA_ESTAÇ¦O TI-_RAG-003-2015_06012015;
- RELATaRIO GRAN TIERRA_PO€O GTE-03-AG_RAG-014-2015_23012015;
- RELATaRIO GRAN TIERRA_PO€O GTE-04 AGUA GRANDE_RAG-009-2015_19012015;
- RELATaRIO GRAN TIERRA_PO€O GTE-04 SERGY_RAG-004-2015_06012015;
- GRAN TIERRA_AMOSTRA DE G¦S NATURAL ESTAÇ¦O TI-_RAG-153_27102015;
- GRAN TIERRA_AMOSTRA DE G¦S NATURAL ESTAÇ¦O TI-_RAG-0030_02032015;
- GRAN TIERRA_AMOSTRA DE G¦S NATURAL ESTAÇ¦O TI-_RAG-0069_20052015;
- GRAN TIERRA_AMOSTRA DE G¦S NATURAL GTE-03-AG_RAG-0089_03072015;
- GRAN TIERRA_AMOSTRA DE G¦S NATURAL GTE-04-SERGI_RAG-0088_03072015;
- GRAN TIERRA_AMOSTRA DE G¦S NATURALGTE-04-AG_RAG-0087_03072015;
- GRAN TIERRA_AMOSTRA DE G¦S NATURAL GTE-03-AG_RAG-0125_25082015;
- GRAN TIERRA_AMOSTRA DE G¦S NATURAL ESTAÇ¦O TI-_RAG-150_30092015;
- GRAN TIERRA_AMOSTRA DE G¦S NATURAL ESTAÇ¦O TI-_RAG-153_01122015; and
- GRAN TIERRA_AMOSTRA DE G¦S NATURAL ESTAÇ¦O TI-_RAG-174_30122015.

7.2 Costayaco and Moqueta

For the Costayaco and Moqueta facilities in Colombia, flared gas and gas-driven turbine generators are metered using Flow Boss meters. Flared gas volume and generator gas consumption data were reported on an annual basis. Monthly diesel consumption data was directly provided by GTE for diesel-driven fire pumps and internal combustion engines. Fuel consumptions used for Costayaco and Moqueta GHG emission calculations are summarized in **Table 3**.

The above fuel and diesel consumption and flared gas volumes were manually input into the information collection spreadsheet tool for summarizing.

Gas analysis was provided in a spreadsheet: Anexo A. Analisis de Cromatografia de gas.xls and was based on samples taken in November, 2015. Five samples were collected at Costayaco and two samples were collected at Moqueta. Based on the analysis results, Moqueta MTQ-1 was considered more representative for tank vapour composition and was used for all three facilities' tank emission calculations. Flared gas and fuel gas properties at these two facilities referred to the Tie Field gas analyses.

Table 3: Fuel Consumption Used for GHG Quantification

Facility	Combustion Source Type	Source ID	Manufacturer	Model	Equipment Output Rating	Fuel Type	Fuel Volume	Unit	Measurement
Tie Field	Fire Pumps	B-6011.01-003B	MWM	D229-6 G.G	90 HP	Diesel	0.057	m^3/month	Calculated based on output rating, running hours and load factor
	Internal Combustion Engine Generator	GE-6011.001	Stemac / MWM	Cramaco G2R / 6.12 TCA	313 HP	Diesel	0.993	m^3/month	Calculated based on output rating, running hours and load factor
	Heater/treater	TO-6011.01-001	Fluxotecnica	VP-HOT-1233-4570-521	N/A	Gas	330	m^3/day	Measured Fuel Volume by the meter
CPF Costayaco	Firm Pumps	ENG-4711	John Deere	6068 Series	110 HP	Diesel	0.04	m^3/month	Invoice/estimated consumption
	Firm Pumps	ENG-1649	John Deere	4045 Series	39 HP	Diesel	0.04	m^3/month	Invoice/estimated consumption
	Internal Combustion Engine	GEN-7202	PERKINS	1103A-33G	40,7 HP	Diesel	2	m^3/month	Invoice/estimated consumption
	Internal Combustion Engine	GEN-7201	PERKINS	404D-22G	38,6 HP	Diesel	2	m^3/month	Invoice/estimated consumption
	Internal Combustion Engine	GEN-8201	CATERPILLAR	C-27	800 HP	Diesel	2	m^3/month	Invoice/estimated consumption
	Internal Combustion Engine	GEN-C307	CUMMINS	6BT	121 HP	Diesel	2	m^3/month	Invoice/estimated consumption
	Internal Combustion Engine	CCY-GE-1101	PERKINS	1006TAG14	197 HP	Diesel	2	m^3/month	Invoice/estimated consumption
	Internal Combustion Engine	GEN-C301	CATERPILLAR	3512C	1000 HP	Diesel	2	m^3/month	Invoice/estimated consumption
	Internal Combustion Engine	GEN-C302	CATERPILLAR	3512C	1000 HP	Diesel	2	m^3/month	Invoice/estimated consumption

	Internal Combustion Engine	GEN-C303	CATERPILLAR	3512C	1000 HP	Diesel	2	m^3/month	Invoice/estimated consumption
	Internal Combustion Engine	GEN-C304	CATERPILLAR	3512C	1000 HP	Diesel	2	m^3/month	Invoice/estimated consumption
	Internal Combustion Engine	GEN-C305	CATERPILLAR	C15	474 HP	Diesel	2	m^3/month	Invoice/estimated consumption
	Internal Combustion Engine	GEN-C306	CATERPILLAR	C15	474 HP	Diesel	2	m^3/month	Invoice/estimated consumption
	Turbine generators	PM1	MWM - CATERPILLAR	TCG2020	1500 KW	Gas	1777788	m^3/year	Metered
	Turbine generators	PM2	MWM - CATERPILLAR	TCG2020	1500 KW	Gas	1777788	m^3/year	Metered
	Turbine generators	PM3	MWM - CATERPILLAR	TCG2020	1500 KW	Gas	1777788	m^3/year	Metered
	Turbine generators	PM4	MWM - CATERPILLAR	TCG2020	1500 KW	Gas	1777788	m^3/year	Metered
	Turbine generators	PM5	MWM - CATERPILLAR	TCG2020	1500 KW	Gas	1777788	m^3/year	Metered
CPF MOQUETA	Internal Combustion Engine	ENG-9261	CATERPILLAR	3406	360 HP	Diesel	**2**	m^3/month	Invoice/estimated consumption
	Internal Combustion Engine	ENG-9535	CATERPILLAR	3406	360 HP	Diesel	**2**	m^3/month	Invoice/estimated consumption
	Turbine generators	G - 1	MWM - CATERPILLAR	TCG2016	500 KW	Gas	1565610	m^3/year	Metered
	Turbine generators	G - 2	MWM - CATERPILLAR	TCG2016	500 KW	Gas	1565610	m^3/year	Metered

Note: Grey sources are owned by third party and their total emissions are not calculated under GTE.

8.0 Conclusions

The 2015 Baseline GHG emissions for GTE are summarized in **Table 4** by emission source category, facility and total emissions. The results show a total of 2015 GHG emissions within the reporting boundary were **55,890.00 tonnes CO_2e.** Of note among the 2015 totals, Tie Field, Costayaco and Moqueta contributed 44.26%, 25.70% and 30.04% of total CO_2e emissions, respectively.

At Tie Field, the flare contributed 38.38% and venting contributed 5.06% of the total CO_2e emissions. All other combustion emission sources, together with fugitive emissions, contributed less than 1% of total CO_2e emissions.

For Costayaco, the flare contributed 13.86% and venting contributed 10.50% of total CO_2e emissions. All other combustion emission sources, together with fugitive emissions, contributed less than 3%.

At Moqueta, venting is the biggest emission source, contributing 23.07% to the total CO_2e emissions. The flare contributed 6.31% of the total.

For both Costayaco and Moqueta, gas-driven turbine generators are located within the facility physical boundary, but are owned and operated by other companies. The fuel consumption data was provided and emissions were calculated for the GTE as reference information. Therefore, the emissions from gas-driven turbine generators were not counted under the GTE 2015 GHG emissions.

Table 4: GHG Emission Summary for Each Facility and Total Emissions

Facility	Emission Category	Emission Source	t CO_2	t CH_4	t N_2O	Total tCO_2e	Percentage of Total CO_2e
			tonnes/year				%
Tie Field	Stationary Combustion	Diesel Fire Pumps	1.87	7.55E-05	1.51E-05	1.87	0.00%
		Diesel Internal Combustion Engine Generator	32.45	1.31E-03	2.63E-04	32.56	0.06%
		Gas Heater/Treater	341.52	4.52E-03	1.26E-03	342.00	0.61%
	Mobile Combustion	3 Pick-up trucks and 1 VW Gol	21.11	8.95E-04	1.79E-04	21.18	0.04%
	Flaring	TA-6011.01-001	14,847.31	51.23	17.86	21,451.45	38.38%
	Tank Venting	TQ-6011-01005	14.10	112.51	-	2,826.94	5.06%
	Fugitive	Fugitive Components	0.46	2.36	-	59.57	0.11%
	Total Emission for Tie Field		**15,258.82**	**166.12**	**17.87**	**24,735.59**	**44.26%**
CPF Costayaco	Stationary Combustion	Diesel Fire Pumps	2.62	1.06E-04	2.12E-05	2.62	0.005%
		Diesel Internal Combustion Engine Generator	719.26	0.03	0.01	721.73	1.29%
		Turbine Generators	24,728.83	1.69	0.61	24,951.51	-
	Flaring	TEA ALTA	4,888.03	16.87	5.88	7,062.25	12.64%
		TEA BAJA	473.21	1.63	0.57	683.70	1.22%
	Tank Venting	GB-201 and GB-202	29.27	233.49	-	5,866.63	10.50%
		Produced Water Tank	-	7.01	-	-	0.00%
	Fugitive	Fugitive Components	0.20	1.02	-	25.79	0.05%
	Total Emission for CPF Costayaco		**6,112.59**	**26006**	**6.46**	**14,362.73**	**25.70%**
CPF Moqueta	Stationary Combustion	Diesel Internal Combustion Engine Generator	341.52	4.52E-03	1.26E-03	342.00	0.61%
		Turbine Generators	8,710.98	0.59	0.21	8,789.42	-
	Flaring	TEA ALTA	1,954.65	6.74	2.35	2,896.64	5.05%
		TEA BAJA	488.66	1.69	0.59	706.02	1.26%
	Tank Venting	GB-601	64.32	513.10	-	12,891.77	23.07%
	Fugitive	Fugitive Components	0.2169	1.11	-	27.83	0.05%
	Total Emission for Moqueta		**2,849.37**	**522.64**	**2.94**	**16,791.71**	**30.04%**
Total Emissions for Gran Tierra			**24,220.80**	**948.80**	**27.3**	**55,890.00**	**100.00%**

Note: Grey sources are owned by a third party and their total emissions are not calculated under GTE.

9.0 Recommendations

The 2015 GHG baseline was developed using the best available operational data and most representative gas analyses at the time of reporting. According to the GHG reporting principles, to improve the accuracy and completeness of the GHG reporting, some potential opportunities are identified for future improvement:

1. A reliable and updated process flow chart will be valuable for identifying the complete emission sources and representative gas analysis. A document of the operational changes, addition or removal of equipment in the reporting year will give a better support of tracking the variety of GHG emissions year by year.
2. For the biggest GHG contributor (flare emissions), rather than using monthly gas analyses, it is suggested that the relative monthly flared volumes are metered and recorded. In this way the calculated monthly carbon content, HHV and molecular weight applied to respective monthly flare volumes will improve emission accuracy.
3. Currently, the tank breathing and working emissions are assumed to be zero and flashing emissions are estimated based on correlation equations (i.e., the Vasquez-Beggs Equation) due to limited availability of tank and product property parameters. Using the E& P TANKS model is recommended for quantifying flashing, breathing and working emissions.
4. A better inventory of vulnerable leak components should be prepared for fugitive emission estimation. In the report, the leak components were estimated based on the limited equipment information.
5. Venting gas volumes and relative gas compositions should be recorded during maintenance, turn over activities and non-routine emergency conditions for quantifying the related venting emissions. The activities include, but not limited to:
    - mud degassing;
    - low pressure gas well casing;
    - pipeline pigging;
    - gathering pipeline blowdowns;
    - vessel blowdowns;
    - emergency shutdown / emergency safety blowdown;
    - pressure relief valves (PRVs);
    - well unloading and workovers; and,
    - well blowouts (when not flared).
6. In addition to fuel estimates based on fuel consumption from invoices, it is recommended that direct measurement using a flowmeter is used at least once a year. Leak detection measurements would assist in refining these estimates.
7. A fully transparent data management system would assure that the operational and fuel data is relevant, accountable, accurate, transparent and trackable for GHG reporting

purposes. The management system should clearly describe the process and relevant quality control and assurance procedures for data collection, transfer, documentation, storage, backup and reporting.

8. The meter calibration records should be kept and be accessible to auditors or users.

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Appendix A

Methodology Report
Gran Tierra Greenhouse Gas Emissions Quantification Study
South America

Novus Reference No. 15-0347 June 15, 2016

NOVUS PROJECT TEAM:

Engineer:	Reanna Zhang, P.Eng.
Scientist:	Laura Clark, B.Eng., E.I.T.
Project Manager:	Craig Vatcher, CET, B.Tech.
Senior Specialist:	Dr. Xin Qiu ACM, EP, P.Met.

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Table of Contents

1.0 Introduction

The greenhouse gas (GHG) baseline reporting for Gran Tierra Energy's (GTE's) conventional oil production and processing facilities follows the *Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions* (2011) (the Guidelines), developed by the International Petroleum Industry Environment Conservation Association (IPIECA), API (American and Petroleum Institute) and OGP (International Association of Oil and Gas Producers).

The Oil and Gas Industry Guidance on Voluntary Sustainability Reporting was updated in 2010 by IPIECA to reflect changing practices. IPIECA and the American Petroleum Institute (API) jointly initiated the development of the second edition of the Guidelines to "continue to promote credible, consistent and reliable greenhouse gas accounting and reporting practices from oil and gas operations".

1.1 Calculation Methodology References

The petroleum industry has recognized the need for GHG accounting and reporting guidance that is focused specifically on its operations. To help meet the need, the API first published the *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry* (the Compendium) in April, 2001, with a third edition released in August, 2009.

The GHG methodologies applied to GTE's operation are first based on those outlined within the Compendium. If an appropriate methodology is not specified based on the existing operational information, an alternative methodology may be referred to, such as those prescribed by the United States Environmental Protection Agency (US EPA), Canadian Association of Petroleum Producer (CAPP) or other relevant authorities.

1.2 Calculation Tool

A spreadsheet was developed to calculate the GHG emissions for all GTE facilities and their associated equipment that documents the related constants, conversion, equations and gas analyses used for the calculations. All calculations, constants and factors utilized within the calculation tool are outlined within the contents of this report. The calculation tool is attached to the report documents as an appendix.

2.0 Global Warming Potential

Global warming potential (GWP) is a relative measure of the warming effect that the emission of a GHG might have on the Earth's atmosphere. It is calculated as the ratio of radiative forcing (i.e. the amount of heat-trapping potential) that would result from the emission of 1 kg of a given GHG to the emission of 1 kg of CO_2.

The GWPs used in the calculations of carbon dioxide equivalent (CO_2E) are consistent with the *IPCC Fourth Assessment Report* included in IPIECA Guideline Table 5-1 and Compendium Table 3-1 (after 2012), as follows:

$$CO_2E = CO_2(1) + CH_4(25) + N_2O(298)$$

Where:

CO_2E =	CO_2 equivalent (tonnes/month)
CO_2 =	CO_2 emissions (tonnes/month)
CH_4 =	CH_4 emissions (tonnes/month)
N_2O =	N_2O emissions (tonnes/month)
1 =	GWP for CO_2
25 =	GWP for CH_4
298 =	GWP for N_2O

3.0 Fuel Consumption

For CO_2 emissions from stationary combustion sources, the first approach relies on a measurement program to obtain the combusted fuel consumption rate (in terms of mass or volume) and composition (i.e., carbon content). If such information is not available, manufacturer data, device-specific testing, or published emission factors are used.

The fuel consumption that was directly metered was collected from GTE, who provided average fuel consumption data that was were assumed to be distributed evenly on a monthly basis based in order to calculate the total annual consumption for 2015. For gas-fired equipment sources for which fuel gas volumes are not individually metered, the theoretical volume of fuel gas combusted is estimated using operating data and equipment ratings. The fuel consumption estimation equation is based on Compendium equation 4-5, below.

3.1 Theoretical Fuel Estimation

$$FC = ER \times LF \times OT \times \frac{1}{ETE} \times H$$

Where:

FC =	annual fuel consumed (volume/yr);
ER =	equipment rating (hp, kW, or J);
LF =	equipment load factor (fraction);
OT =	annual operating time (hr/yr);
ETE =	equipment thermal efficiency (Btu input/hp-hr output, Btu input/kW-hr output, or J input/J output);
HV =	fuel heating value (energy/volume).

To calculate the theoretical fuel of reciprocating engines or fire pumps, the following equation was adapted from Compendium equation 4-5 for engines and fire pumps.

$$fuel_{theoretical,Ei} = Output_{Ei} \times \frac{1}{TE_{Ei}} \times \frac{1}{HHV} \times RT_{Ei} \times LF_{Ei} \times 2.6845 \times 10^{-3}$$

Where:

$fuel_{theoretical,Ei}$ =	theoretical volume of fuel combusted for engine i (m^3/month)
$Output_{Ei}$ =	site rated output power for engine i (hp)
TE_{Ei} =	engine thermal efficiency on a HHV basis for engine i. (assumed 0.35)
2.6845×10^{-3} =	conversion factor from hp-hr to GJ
HHV =	higher heating value of fuel gas (GJ/m^3)
RT_{Ei} =	monthly engine runtime for engine i (hr/month)
LF_{Ei} =	monthly average load factor for engine i (fraction)

4.0 Gas Properties

Gas analyses are performed on the various gas streams in order to determine the molecular components of the gas and their respective molar fractions. Using the results from a gas analysis and published values for physical properties, the fuel gases higher and lower heating values, carbon content and molecular weight can be determined.

4.1 HHV and LHV

The heating value of a fuel is described as the amount of heat produced by the complete combustion of a unit quantity of fuel. Heating value can either be classified as higher heating value (HHV) or lower heating value (LHV), depending on the phase of the water formed during combustion. Higher heating value is obtained when the water formed appears as a liquid, and lower heating value is obtained when the water formed appears as a vapor.

The higher and lower heating values of the fuel gas are calculated by summing the products of the mole fraction and the heating value of each fuel gas component, as shown in the following equations:

$$LHV = \sum_i^n x_i LHV_i \qquad \text{Equation 4.1-1}$$

$$HHV = \sum_i^n x_i HHV_i \qquad \text{Equation 4.1-2}$$

Where:

HHV =	higher heating value of fuel gas (GJ/e^3m^3)
LHV =	lower heating value of fuel gas (GJ/e^3m^3)
x_i =	mole fraction of component
HHV_i =	higher heating value of component (GJ/e^3m^3)
LHV_i =	lower heating value of component (GJ/e^3m^3)

Values for gross heating value HHV are obtained from *Table 3-7: Hydrocarbon Molecular Weights and Gross Heating Values of the Compendium*. The mole fractions of the gas components are obtained from gas analyses of the fuel stream.

4.1.1 Carbon Content

The carbon content of a fuel is calculated from the sum of the mole percent of each component multiplied by the number of carbon atoms in each molecule. The following equation is equivalent to Compendium equation 4-9 and used to calculate the carbon content:

$$CC_{mol} = \sum_i^n x_i C_{ni} \qquad \text{Equation 4.1-3}$$

Where:

CC_{mol} =	fuel carbon content (kmol carbon/ kmol fuel)
x_i =	mol fraction of component in fuel (kmol component/kmol fuel)
C_{ni} =	number of carbon atoms in the component

The following equation converts the carbon content from a mole basis to a mass basis.

$$CC_{mass} = CC_{mol} \times \frac{12.011}{MW} \qquad \text{Equation 4.1-4}$$

Where:

CC_{mass} =	carbon content mass basis (Kg carbon/Kg fuel)
CC_{mol} =	carbon content mole basis (Kmol carbon/Kmol fuel)
12.01 =	molecular weight of carbon (Kg /Kmol)
MW =	molecular weight of fuel gas (Kg /Kmol)

4.1.2 Molecular Weight

The molecular weight of the fuel gas is found by the summation of the mole fraction of each fuel gas component multiplied by its respective molecular weight, as shown in the following equation which is based on Compendium equation 4-10.

$$MW = \sum x_i MW_i \qquad \text{Equation 4.1-5}$$

Where:

MW =	molecular weight of fuel gas (Kg/Kmole)
xi =	mole fraction of component
MWi =	molecular weight of component (Kg/Kmole)

5.0 Stationary Combustion

5.1 Fuel Gas Combustion

5.1.1 CO_2 Emissions

The carbon content and molecular weight of the fuel gas is used to calculate CO_2 emissions as per the following equation. This methodology is consistent with Compendium methodology. Since the average monthly fuel consumptions were provided by GTE, the average carbon content was calculated based on the provided monthly gas analyses. The equation is consistent with Compendium equation 4-11.

$$E_{CO_2} = 12 \times 3.664 \times V_{fuel} \times MW/23.64 \times CC_{mass} \times 0.001$$

Where:

E_{CO2} =	CO_2 stationary combustion emissions in a year (tonnes/year)
V_{fuel} =	average volume of gaseous fuel combusted in the period (m^3/month)
CC_{mass} =	average carbon content of fuel gas by weight (Kg carbon/Kg fuel) in 2015
MW =	molecular weight of fuel gas (Kg/Kmole)
23.64 =	standard molar volume (m^3 fuel/Kmole)
3.664 =	ratio of molecular weights, CO_2 to carbon (44.01/12.01)
0.001 =	conversion ratio from kg to tonnes;
12 =	12 months per year

A 100% oxidation factor is assumed in the conversion of carbon to carbon dioxide in combustion.

5.1.2 CH_4 Emissions

Methane (CH_4) emissions from stationary fuel gas combustion are calculated by using the fuel rate, higher heating value (derived from gas analysis) and emission factor and the following equation. The emission factors for fuel gas combustion were taken from Table 4-7 for heaters and Table 4-9 for turbines.

For heaters,

$$E_{CH4} = V_{fuel} \times 35.3147 \times 0.000001 \times EF_{CH4} \times 0.45359 \times 0.001$$

Where:

E_{CH4} =	mass emissions from combustion in a year (tonnes/year)
V_{fuel} =	average volume of gaseous fuel combusted in the period (m^3/year)

35.3147×10^{-6} =	conversion factor from m^3 to 106 scf
EF_{CH4} =	CH_4 emission factor (lb × 106 scf)
0.45359 =	conversion factor from lb to kg
0.001 =	conversion factor from kg to tonnes

For gas turbines,

$$E_{CH4} = V_{fuel} \times HHV_{fuel} \times 9.47817 \times 0.0001 \times EF_{CH4}$$

Where:

E_{CH4} =	mass emissions from combustion in a year (tonnes/year)
V_{fuel} =	average monthly volume of gaseous fuel combusted (m^3/year)
HHV_{fuel} =	average higher heating value of fuel gas (MJ/m^3)
9.47817×10^{-4} =	conversion factor from MJ to 10^6 Btu
EF_{CH4} =	CH_4 emission factor (tonnes/10^6 Btu)

5.1.3 N_2O Emissions

N_2O mass emissions are calculated by using the fuel rate, higher heating value (derived from gas analysis) and N_2O emission factor, as per the above CH_4 equations. The emission factors for fuel gas combustion were taken from Table 4-7 for heaters and Table 4-9 for turbines.

5.2 Diesel Combustion

GHG mass emissions are calculated by using the fuel rate, default higher heating value, emission factor and the following equation. The diesel emission factors are categorized based on fuel type and are not equipment specific. Fuel consumption data was provided by GTE. The default high heating value of 38.7 GJ/m^3 was used for diesel fuel taken from Compendium *Table 3-8: Densities, Higher/Lower heating value and Carbon Contents for Various Fuels*. The emission factors in Compendium Table 4-3 and Table 4-5 are referred to for calculation. The emission factors are 70.4, 2.85E-03 and 5.70E-04 tonnes/10^{12}J for CO_2, CH_4 and N_2O, respectively.

$$E_{CO2} = 12 \times V_{fuel} \times HHV \times EF_{CO2} \times 0.001$$

$$E_{CH4} = 12 \times V_{fuel} \times HHV \times EF_{CH4} \times 0.001$$

$$E_{N2O} = 12 \times V_{fuel} \times HHV \times EF_{N2O} \times 0.001$$

Where:

E_{CO2} =	mass emissions from combustion in a year (tonnes/year)
E_{N2O} =	mass emissions from combustion in a year (tonnes/year)
E_{CH4} =	mass emissions from combustion in a year (tonnes/year)
V_{fuel} =	volume of diesel fuel combusted in the period (m^3/month)

HHV =	higher heating value of diesel (38.7 GJ/m^3)
EF =	emission factor for CO_2, CH_4, N_2O (tonnes/1012 J)
0.001 =	conversion factor from GJ to 1012 J
12 =	12 months per year

6.0 Mobile Emissions

Gasoline-powered vehicles are used for employee transportation within the Tie Field plant boundary. Mobile emission rates were calculated for onsite vehicles only.

GHG mass emissions are calculated by using the gasoline fuel rate, default gasoline higher heating value and emission factor for off-road gasoline motors in the following equations.

Greenhouse gas emissions (CO_2, CH_4 and N_2O) from gasoline combustion are calculated using the emission factors in Compendium *Tables 4-3 and 4-5: Combustion Emission Factors for Common Industry Fuel Type* (Fuel Basis) for off-road gasoline motors. The emission factors are 67.2, 2.85E-03 and 5.70E-04 tonnes/10^{12}J for CO_2, CH_4 and N_2O respectively. The higher heating value (HHV) for gasoline (off-road) is 34.9 GJ/m^3, based on Compendium Table 3-8.

$$E_{CO2} = 12 \times V_{fuel} \times 0.001 \times HHV \times EF_{CO2} \times 0.001$$

$$E_{CH4} = 12 \times V_{fuel} \times 0.001 \times HHV \times EF_{CH4} \times 0.001$$

$$E_{N2O} = 12 \times V_{fuel} \times 0.001 \times HHV \times EF_{N2O} \times 0.001$$

Where:

E_{CO2} =	CO_2 mass emissions from combustion in a year (tonnes/year)
E_{N2O} =	N_2O emissions from combustion in a year (tonnes/year)
E_{CH4} =	CH_4 emissions from combustion in a year (tonnes/year)
V_{fuel} =	volume of gasoline fuel combusted in the period (Liter/year)
0.001 =	conversion factor from Liter to m^3
HHV =	higher heating value of gasoline for off-road motor (34.9 GJ/m^3)
EF =	emission factor for CO_2, CH_4, N_2O (tonnes/1012 J)
0.001 =	conversion factor from GJ to 1012 J

7.0 Flaring

7.1 CO/CO_2 Emissions

CO_2 emissions from flaring are estimated assuming a flare combustion efficiency of 98%. The CO_2 already contained in the flaring gas stream is released directly and reported as un-combusted CO_2. Representative site-specific flare gas composition was obtained from a sampled flare gas analysis. CH_4 emissions are calculated assuming 2% non-destructed CH_4.

The CO_2 emissions from the combusted and non-combusted portion of the flare stream are calculated using the following expression which is taken from Compendium equation 4-11.

$$CO_2 = CO_2(combusted) + CO_2(noncombusted)$$

$$E_{\mathrm{CO2,combusted}} = 3.664 \times V_{flare} \times MW_{flare}/23.64 \times CC_{mass,flare} \times \varepsilon \times 0.001$$

Where:

$E_{CO2,\ combusted}$ =	CO_2 flare combustion emissions in a year (tonnes/year)
V_{flare} =	volume of flare gas combusted in the period (m^3/y)
$CC_{mass,\ combusted}$ =	carbon content of combusted flare gas by mass (Kg carbon/Kg gas)
MW_{flare} =	molecular weight of flare gas (kg/kmol gas)
0.001 =	volumetric conversion of kg to tonne
23.64 =	standard molar volume (m^3 gas/Kmol)
3.664 =	molecular weight ratio of CO_2 to Carbon (44.01/12.01)
ε =	flare combustion efficiency (assumed to be 0.98)

$$E_{CO2,uncombusted} = \frac{V_{flare}}{23.64} \times X_{CO2} \times 44.01 \times 0.001$$

Where:

$E_{CO2,\ un\text{-}combusted}$ =	CO_2 flare un-combusted emissions in a year (tonnes/year)
V_{flare} =	volume of flare gas combusted in the period (m^3/y)
X_{CO2} =	CO_2 mole fraction in flare stream (Kmol CO_2/Kmol gas)
44.01 =	molecular weight of CO_2 (Kg/Kmol)
23.64 =	standard molar volume (m^3 gas/Kmol)
0.001 =	volumetric conversion of kg to tonne

7.2 CH_4 Emissions

The methane emissions from the flare are calculated using the following expression, from Compendium equation 4-16.

$$CH_4 = V_{flare}/23.64 \times x_{CH4} \times 16.04 \times (1 - \varepsilon) \times 0.001$$

Where:

CH_4 =	CH_4 emissions in a year (tonnes/year)
V_{flare} =	average volume of flare gas combusted in a month (m^3/year)
x_{CH4} =	mol fraction of CH_4 in flare streaml (Kmol CH_4/Kmol gas)
16.04 =	molecular weight of CH_4 (Kg/Kmol)
0.001 =	mass conversion of kg to tonnes
23.64 =	standard molar volume (m^3 gas/Kgmole)
ε =	flare combustion efficiency (assumed to be 0.98)

7.3 N_2O Emissions

The N_2O emission factor in Compendium Table 4-12 is based on oil production with an uncertainty between -10 and 1000. As this uncertainty is high, an emission factor 0.068 lb/10^6 Btu from AP-42 Table 13.5-1 is used for the N_2O emissions calculations.

N_2O emissions are calculated using the following expression.

$$N_2O = V_{flare} \times HHV_i \times EF/1055.056 \times 0.001$$

Where:

N_2O =	mass emissions from combustion in the period (tonnes/year)
V_{flare} =	volume of gaseous fuel combusted in the period (m^3/year)
HHV =	higher heating value of flare gas (MJ/m^3)
1/1055.056 =	conversion factor of MJ to 10^6 Btu
EF =	N_2O flare emission factor (0.068 lb/10^6 Btu)
0.001 =	conversion factor from kilograms to tonnes

8.0 Venting

8.1 Flashing Emissions

Where liquids are in contact with a gas phase, high pressures will cause some of the gas to go into solution (i.e., thermodynamic equilibrium between the phases will eventually occur). When the liquid is brought back to atmospheric conditions, the solution gas is released through a rapid process called flashing.

Crude oil production tanks emit CH_4 and small quantities of CO_2 through flashing losses, which occur as the pressure drops from the separator conditions to atmospheric pressure in the storage tank. Flashing emissions can be significant where there is a significant reduction in pressure.

Storage tank vent volumes from condensate and oil tanks are estimated using the following equations, sourced from Compendium Exhibit 5-13.

$$R_{vent,flash} = GOR \times Q \times 0.158987 \times (1 - Eff_{VC})$$

Where:

RVent,flash =	flash gas vent rate (Sm^3 gas/year)
GOR =	gas oil ratio (Sm^3 gas/m^3 oil)
Q =	oil production rate (barrel/year)
0.158987 =	volume conversion from barrel (bbl) to cubic meter (m^3)
EffVC =	vapour control efficiency through vapour recovery or flare combustion system (%)

The oil production rate was obtained directly from GTE. The gas-oil ratio (GOR) is calculated according to the Vasquez-Beggs Equation (VBE) Correlation Approach. The approach was referenced from the Oklahoma Department of Environmental Quality (2004).

The first step is to calculate the specific gravity of the gas at 100 psig using the equation from Compendium 5-16:

$$SGx = SGi\left(1.0 + 0.00005912 \times API \times Ti \times Log\left(\frac{Pi + 14.7}{114.7}\right)\right)$$

Where:

SGx = dissolved gas gravity at 100 psig (Sm^3 gas/m^3 oil)
SGi = dissolved gas gravity at initial conditions, where air=1, a suggested default value is 0.9
0.158987= volume conversion from barrel (bbl) to cubic meter m3
Control efficiency = control efficiency through vapor recovery or flare combustion system (%) (90% based on the survey)
API = API gravity of liquid hydrocarbon at final condition
Ti = temperature of initial conditions (°F)
Pi = pressure of initial conditions (psig).

Then, flash GOR is calculated using the equation from Compendium 5-17:

$$Rs = C_1 \times SGx \times (Pi + 14.7)^{C_2} \times \exp(C_3 \times \frac{API}{Ti + 460})$$

Where:

Rs = ratio of flash gas production to standard stock tank barrels of oil produced (scf/bbl foil);
SGx = dissolved gas gravity, adjusted to 100 psig
Pi = pressure in separator (psig)
API = API gravity of stock tank oil at 60 °F
Ti = temperature in separator (°F)

For API<30, C1=0.0362, C2=1.0937 and C3=25.724
For API>30, C1=0.0178, C2=1.187 and C3=23.931

The following section provides information regarding the methodology of calculating the venting volumes, it should be noted that these calculations provide estimated volumes.

CO_2 and CH_4 emissions from venting are calculated based on the venting stream volume and composition based on the following equations. Stream composition is obtained from multiple gas analyses provided by GTE.

$$E_{CO2,flash} = R_{vent,flash} \times mol\ frac_{CO2,vent} \times \frac{44.01}{23.64} * 0.001$$

$$E_{CH4,flash} = R_{vent,flash} \times mol\ frac_{CH4,vent} \times \frac{16.04}{23.64} * 0.001$$

Where:

$E_{CO2,flash}$ =	CO_2 mass emissions from flash venting in the period (tonnes/y)
$E_{CH4,flash}$ =	mass emissions from flash venting in the period (tonnes/y)
$R_{vent,flash}$ =	flash vent rate in the period (m^3/y)
Mol $frac_{CO2,vent}$ =	mol fraction of CO_2 in vent stream
Mol $frac_{CH4,vent}$ =	mol fraction of CH_4 in vent stream
44.01 =	molecular weight of CO_2 (kg/kmol)
16.04 =	molecular weight of CH_4 (kg/kmol)
23.64 =	standard molar volume (m^3 vent/Kmole)

8.2 Storage Emissions

Once the condensate/crude oil reaches atmospheric pressure and the volatile CH_4 has flashed off, the crude is considered "weathered" or "stabilized". Unless site-specific data indicate otherwise, "weathered" crude is assumed to have no CH_4 or CO_2, which means the breathing and working loss are assumed to be zero. At GTE facilities, oil first gets flashed from separators to gun-barrels and is then sent to storage tanks. The final product sent to the tanks are considered weathered products, so the emissions from breathing and working losses in the storage tanks are assumed to be zero.

8.3 Produced Water Emissions

Methane has a weaker affinity for water than it does for hydrocarbon oil, thus methane emissions from produced water tanks are lower than crude tank flashing losses because more CH_4 is dissolved in the oil phase than the water phase. The emission calculation is based on the emission factor developed from the Gas Research Institute (GRI) and U.S. EPA study for Methane Emissions from the Natural Gas Industry (1996). The GRI/EPA study estimated produced water emissions based on process simulator modeling for salt contents of 2, 10, and 20 %, and pressures of 50, 250, and 1000 psi. The emission factor closest to the facility separator pressure and salt content was chosen for CH_4 emissions quantification.

$$E_{CH4,PW} = EF_{CH4,PW} \times P_{pw} * 0.001$$

Where:

$E_{CH4,pw}$ =	produced water CH_4 emissions in a year (tonnes/year);
EF_{pw} =	produced water CH_4 emission factor (tonnes/1000 bbl produced water);
P_{pw} =	produced water production rate (bbl/year)
0.001 =	conversion factor of bbl to 1000 bbl.

9.0 Fugitive Equipment Leaks

The component-level average emission factor approach used is based on CAPP methodology.

The inventory of Component Counts is compiled by applying a count factor to the total of each type of equipment. The count factor is classified by component (e.g., connector, valve, pressure relief valve, pump seals, flanges, etc.) and by service (fuel gas, gas/vapour, light liquid and heavy liquid). Then, a specific emission factor for each component is multiplied by the total count components for the equipment in order to get the total emissions for that piece of equipment.

A representative stream composition for the light liquid service was obtained from Tables 3 to 5 of CAPP's *Volume 3 UOG Emissions Inventory Methodology Manual* (Clearstone 2014).

Fugitive emissions are calculated for a type of equipment by applying the following equation (WCI Equation 360-37).

$$E_{CH4/CO2,eqp\,fug} = \sum_{k}\sum_{l}\left(N \times N_{k,l} \times \frac{EF_{k,l}}{THC_k} \times X_{i,k}\right) \times t \times 0.001$$

Where:

$E_{CH4/CO2,eqp,fug}$ =	annual total mass emissions of GHG i (CH_4 or CO_2) at standard conditions from a type of major equipment at the facility (tonnes/y)
N =	number of a type of equipment
$N_{k,l}$ =	number of components in service k and component type l for the piece of equipment
$EF_{k,l}$ =	THC emission factor for a component in service k and component type l (kg/h)
THC_k =	total hydrocarbons in service k
$X_{i,k}$ =	mass fraction of GHG i (CH_4 or CO_2) in service k
t =	total time the specific source associated with the fugitive equipment leak was operational in a year (hr/year)
0.001 =	conversion from kg to tonnes

$N_{k,l}$ values are taken from Table 12: *schedule of default component counts per equipment or process type (for* light liquid) from CAPP's *Update of Fugitive Equipment Leak Emission Factors* (Clearstone 2014).

$EF_{k,l}$ values are taken from Table 10: *Final consolidated emission factor for application in estimating fugitive emissions from upstream oil and gas facilities after the implementation of a form DI&M (for oil)* from the same above CAPP document.

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