



**The Climate Registry**

# **OIL & GAS PRODUCTION PROTOCOL**

**Annex II to the General Reporting Protocol**

**February 2010**

**Version 1.0**

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## ABOUT THIS PROTOCOL

The Registry developed this Oil and Gas Production protocol (O&GP Protocol) to provide greenhouse gas (GHG) calculation and reporting direction to Members of The Climate Registry (The Registry) with operations in the Oil and Gas (O&G) Exploration and Production (P) sector.

The O&GP Protocol is a supplemental annex to The Registry's General Reporting Protocol (GRP). It specifies additional reporting requirements and options for Registry Members with operations in the O&GP sector. The document includes additional calculation methodologies for emission sources unique to the sector, and addresses how requirements in the GRP must be applied to this sector. It is important to note that Members required to use the O&GP protocol will also need to use the GRP to quantify emissions from sources not specific to this sector. In order to facilitate coordinated use of the GRP and the O&GP Protocol, the O&GP Protocol's structure closely mirrors that of the GRP.

The Western Governors Association's (WGA) and the Western Regional Air Partnership (WRAP) sponsored the development of the O&GP protocol. Representatives from the State of California, the State of New Mexico, and The Registry comprised the Steering Committee which oversaw the development of the O&GP Protocol.

The Registry would like to extend special thanks to the steering committee participants as well as to SAIC and ENVIRON for their contribution to the O&GP protocol. In addition, The Registry wishes to thank its Protocol Committee and staff members Jill Gravender and Zoe Elizabeth for their work to finalize the document. Tom Moore of WRAP deserves special thanks for his leadership throughout this project. Finally, The Registry's Policy Manager, Peggy Foran, deserves special thanks and acknowledgement for spearheading the development of the O&GP protocol for The Registry.

The O&GP Protocol benefited from the substantial input provided by WRAP's O&GP Technical Workgroup.

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## ABBREVIATIONS AND ACRONYMS

AEUB	Alberta Energy and Utilities Board
API	American Petroleum Institute
Bbl	Barrels
Btu	British Thermal Unit(s)
CAC	Criteria Air Contaminant
CAPP	Canadian Association of Petroleum Producers
CEM	Continuous Emissions Monitoring
CHP	Combined Heat and Power
COP	Coefficient of Performance
EOS	Equation of State
EPA	United States Environmental Protection Agency
EUB	Energy Utility Board
EU-ETS	European Union Emission Trading Scheme
EF	Emission Factor
FGD	Flue Gas Desulphurization
ft <sup>3</sup>	Cubic Feet
GC/MS	Gas Chromatography-Mass Spectrometry
GHG	Greenhouse Gas
GOR	Gas to Oil Ratio
GRP	The Registry's General Reporting Protocol
GWP	Global Warming Potential
HFC	Hydrofluorocarbon
HHV	Higher Heating Value
IPCC	Intergovernmental Panel On Climate Change
Kg	Kilogram(S)
Lb	Pound
M	Meter
m <sup>3</sup>	Cubic Meter
t	tonne
MW	Molecular Weight
OS/HOU	Oil Sands and Heavy Oil Upgrading
O&G	Oil and Gas
O&GP	The Registry's Oil and Gas Production Protocol
PFC	Perfluorocarbon
RVP	Reid Vapor Pressure
THC	Total Hydrocarbon
VBE	Vasquez-Beggs Equation
VOC	Volatile Organic Compound
WBCSD	World Business Council For Sustainable Development
WGA	Western Governors' Association
WRAP	Western Regional Air Partnership
WRI	World Resources Institute
Wt%	Weight Percent



## PART I: INTRODUCTION

The Registry developed this Oil and Gas Production protocol (hereafter referred to as the O&GP Protocol) to provide greenhouse gas (GHG) calculation and reporting direction to Members of The Climate Registry (The Registry) with operations in the Oil and Gas (O&G) Exploration and Production sector.

This O&GP protocol is a supplemental annex to The Registry's General Reporting Protocol (GRP). The GRP describes The Registry's voluntary reporting program and provides the basic framework for all Registry Members<sup>1</sup> to report their GHG emissions.

### The General Reporting Protocol

The Registry's GRP is designed to promote the complete, transparent, and accurate reporting of GHG emissions in a fashion that minimizes the reporting burden and maximizes the benefits associated with understanding the connection between fossil fuel consumption, energy production, and GHG emissions. The GRP contains reporting and quantification requirements for common types of GHG emission sources such as stationary and mobile combustion devices. You must adhere to the GRP's reporting requirements in order for The Registry to accept and publicly publish your annual GHG inventories. If your organization has operations in the O&GP sector, you must additionally adhere to the O&GP Protocol reporting requirements.

### O&GP Protocol

This O&GP Protocol specifies additional reporting requirements and options for Members with operations in the O&GP sector. It includes additional calculation methodologies for emission sources unique to the sector and explains how GRP requirements must be applied to this sector. This Annex also provides specific interpretation of the GRP reporting requirements for the O&GP sector's unique operations, including drilling and completions, workovers, and natural gas processing. As in the GRP, all GHG emission calculation methodologies mandated by a State, Provincial, or Federal GHG reporting program are acceptable for reporting emissions from O&GP sector activities to The Registry. Please refer to the text box at the end of this section for a description of organizations that are required to use the O&GP Protocol.

Figure 1.1 shows an overview of the sector processes within the O&GP sector, and indicates which processes are, and are not, covered in this protocol. Table 1.1 provides a more detailed list of each of these specific processes.

In The Registry's definition of the O&GP sector the precise point at which the exploration and production phase of activity is completed and the next phase (of processing or transmission) begins depends on the product (oil or natural gas). In the case of oil, The Registry has classified

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<sup>1</sup> The Registry changed its nomenclature from "Reporters" to "Members" in the fall of 2008 to reflect the leadership Members demonstrate by reporting their emissions to The Registry and to highlight that its Members are part of a group of organizations committed to the application of best practices in GHG reporting.

and included quantification methodologies for *all* of the activities associated with drilling, production, and transportation of the crude oil<sup>2</sup> as O&GP sector activities. The Registry recognizes that within the oil and gas industry, crude oil transportation is considered a separate sector from the O&GP sector, and is typically handled by entities different from oil and gas producers, as transportation entities are subject to separate transportation regulations arising from their common carrier status. Nonetheless, the O&GP Protocol includes crude oil transportation to avoid potential gaps in GHG reporting guidance.

Crude oil transportation emissions sources covered in the O&GP Protocol include oil pipelines, trains, trucks, and marine vessels. Activities *downstream* of the crude oil transportation process, including refining as well as transportation, storage and distribution of petroleum products, are *not* addressed in the O&GP Protocol. In other words, this protocol covers all activities up to *the refinery gate*.

In the case of natural gas, the O&GP Protocol provides reporting guidance and requirements for *all* activities upstream of the meter that marks the transfer of custody to a pipeline system in which delivered gas is required to meet pipeline tariff specifications. Therefore, this O&GP Protocol applies to all activities associated with natural gas drilling, production, *and processing*. Emissions from natural gas transmission, storage, and distribution are not addressed in this O&GP Protocol.

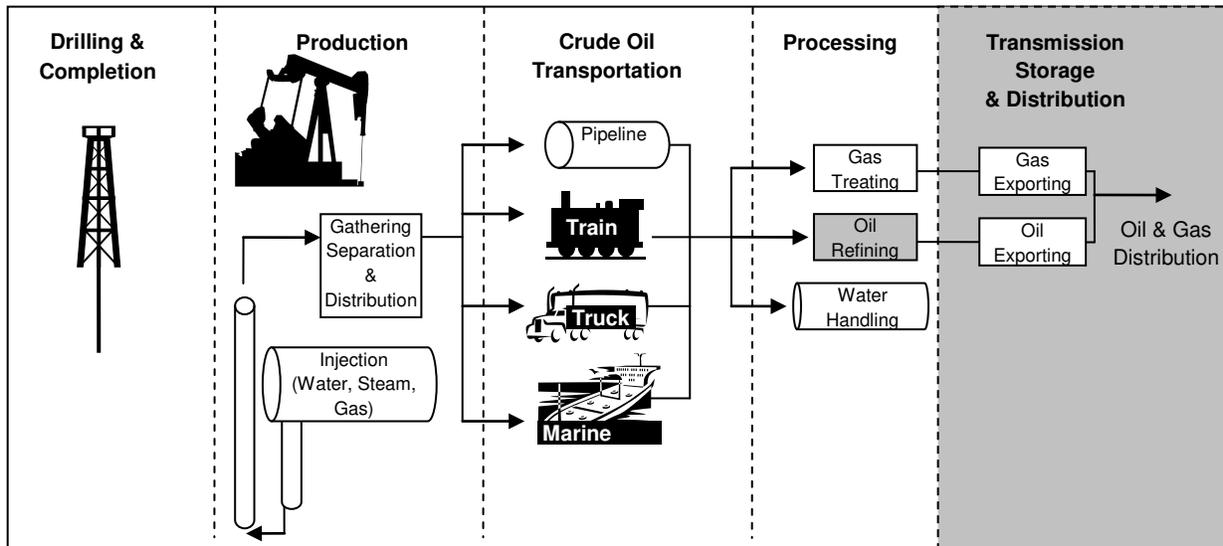
In addition, although most straddle plant operations are conducted downstream of oil and gas production, quantification methodologies for straddle plants are included in the O&GP Protocol because natural gas is sometimes liquefied upstream of the point of custody transfer.

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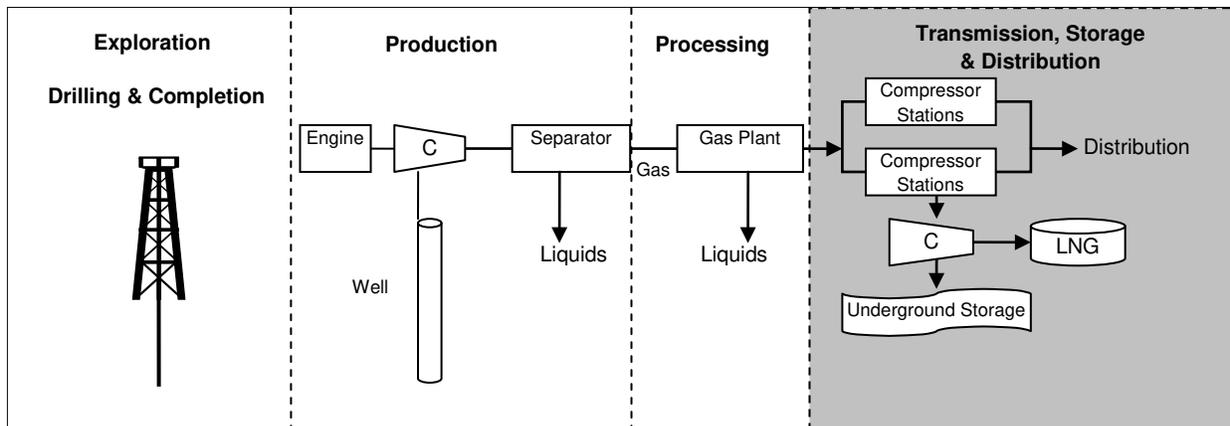
<sup>2</sup> Members need only report emissions from those operations that fall within their own organizational boundaries.

Figure 1.1 – Oil and Natural Gas Sources Covered in this Protocol

**Oil Industry Sources Covered in this Protocol**



**Natural Gas Industry Sources Covered in this Protocol**



This O&GP Protocol does not address operations shown in the shaded areas.

**Table 1.1 – Activities, Processes and Emission Sources Covered in this Protocol**

<b>Activity, Process or Source</b>
Amine Units
Artificial Lift Engines (Pumpjacks)
Boilers/Steam Generators
Completion Venting
Compressor Blowdowns
Compressor Start-ups and Shutdowns
Crude Oil Transportation by Pipeline, Train, Trucks and/or Marine Vessels
Dehydrators
Drill Rigs
Electricity Imports
Exploratory Drilling
Frac Pumps
Gas Pipeline Fugitives
Gas Processing Plant Fugitives
Gas Well Fugitives
Gas Well Heaters
Gas Well Tanks—Flashing, and Working and Breathing Losses
Gas Well Truck Loading
Gas Turbines
Heavy-Duty Trucks
Flares
Large Compressor Engines
Lateral/Wellhead Compressor Engines
Light-Duty Trucks
Medium-Duty Trucks
Miscellaneous Engines
Miscellaneous Gas-Fired Heaters or Boilers
Oil Pipeline Fugitives
Oil Well Fugitives
Oil Well Heaters
Oil Well Tanks—Flashing, and Working and Breathing Losses
Oil Well Truck Loading
Pipeline Blowdowns
Planes/Helicopters
Pneumatic Devices
Process Heat/Steam Imports
Salt-Water Disposal (SWD) Engines
Supply Boats/Barges
Vapor Recovery Unit (VRU) Engines
Water Treatment Facilities
Well Blowdowns
Well Testing
Workover Rigs

### **Applicability: Who Must Use the O&GP Protocol?**

If you own or control oil or natural gas exploration and production operations, you must comply with the O&GP Protocol's reporting requirements.

As defined by NAICS industry code 21111<sup>3</sup>, this industry comprises establishments primarily engaged in operating and/or developing oil and gas production field properties and recovering liquid and gaseous hydrocarbons from these fields. Such activities may include exploration for crude petroleum and natural gas; drilling, completing, and equipping wells; operation of separators, emulsion breakers, desilting equipment, and production field gathering lines for crude petroleum and natural gas; and all other activities in the preparation of oil and gas up to the point of shipment from the producing property. In addition, Members involved in natural gas processing, or in the transportation of crude oil from the producing field to the refinery gate, must use this protocol to calculate emissions associated with the natural gas processing or crude oil transportation components of their operations.

This industry includes the production of crude petroleum, the mining and extraction of oil from oil shale and oil sands, the production of natural gas, sulfur recovery from natural gas, and the recovery of hydrocarbon liquids from oil and gas field gases. Specific components of NAICS industry 21111 include Crude Petroleum and Natural Gas Extraction (NAICS Code 211111) and Natural Gas Liquid Extraction (NAICS Code 211112). These are described as follows:

#### **Crude Petroleum and Natural Gas Extraction (NAICS Code 211111)**

This industry comprises establishments primarily engaged in:

- 1) The exploration, development and/or the production of petroleum or natural gas from wells in which the hydrocarbons will initially flow or can be produced using normal pumping techniques; or
- 2) The production of crude petroleum from surface shales or oil sands or from reservoirs in which the hydrocarbons are semisolids. Establishments in this industry operate oil and gas wells on their own account or for others on a contract or fee basis.

#### **Natural Gas Liquid Extraction (NAICS Code 211112)**

This industry comprises establishments primarily engaged in the recovery of liquid hydrocarbons from oil and gas field gases. Establishments primarily engaged in sulfur recovery from natural gas are included in this industry.

<sup>3</sup> <http://www.census.gov/epcd/naics02/def/NDEF211.HTM#N211>

If you provide support services (on a contract or fee basis) that are required for the extraction of oil and gas (including NAICS codes 213111, 213112, and 541360), as well as Members with oil transportation operations (including NAICS code 486110—crude oil pipeline transportation— and NAICS code 424710—crude oil terminals), you must also comply with the O&GP Protocol’s reporting requirements.

A single entity, such as a vertically integrated oil producer, refiner, and distributor, may own or control some emission sources falling within the scope of the O&GP Protocol, and some that fall outside this protocol’s scope. Such vertically integrated entities are required to use this protocol to report all relevant emissions resulting from exploration and production activities.

## **PART II: DETERMINING WHAT YOU SHOULD REPORT**

### **Chapter 1: Introduction**

REFER TO GRP.

## Chapter 2: Geographic Boundaries

### 2.1 Required Geographic Boundaries

The Registry requires Climate Registered Members to report GHG emissions from all sources located in Canada, Mexico, and the U.S. In addition, you must identify GHG emissions that occur on lands designated to participating Native Sovereign Nations. The Registry encourages, but does not require you to report GHG emissions from sources outside of North America.

Outside of the O&GP sector GHG emission sources are typically located onshore. For more information on the geographic boundaries of onshore emission sources, please refer to the GRP. Geographic boundaries for *offshore* facilities are further discussed below.

#### 2.1.1 Offshore Oil and Gas Activities

Offshore oil and gas activities can be located within international, federal or state/provincial jurisdictions. The O&GP Protocol requires you to report emissions from offshore activities according to the jurisdiction with leasing and regulatory authority over each activity. In the U.S., most coastal states control the territory extending 3.45 statute miles from the shore (measured at mean low tide), and have jurisdiction to decide whether or not, and under what terms, to lease this territory for oil and gas exploration and production.<sup>4</sup>

Under international law, national control generally extends 200 nautical miles from the shoreline. The area enclosed within this 200-mile boundary is called a nation's "Exclusive Economic Zone" (EEZ). However, the EEZ may extend beyond 200 miles if the outer limits of the continental margin<sup>5</sup> go past that boundary. In the U.S., the EEZ extends beyond 200 miles north of Alaska, and along the Atlantic and Gulf Coasts. Along the Pacific Coast the standard 200-mile boundary applies. In the Gulf of Mexico, a small area, referred to as the "doughnut hole," lies beyond the EEZ's of both Mexico and the U.S. and has been divided between these two countries by treaty.

#### 2.1.2 Example: Applying Jurisdictional Boundaries

ACME Oil has five drilling platforms operating in the Pacific Ocean. Two of these platforms, A and B, are located one mile and two miles, respectively, from the shoreline of California (as defined at mean low tide). Two more platforms, C and D, are each located approximately 50

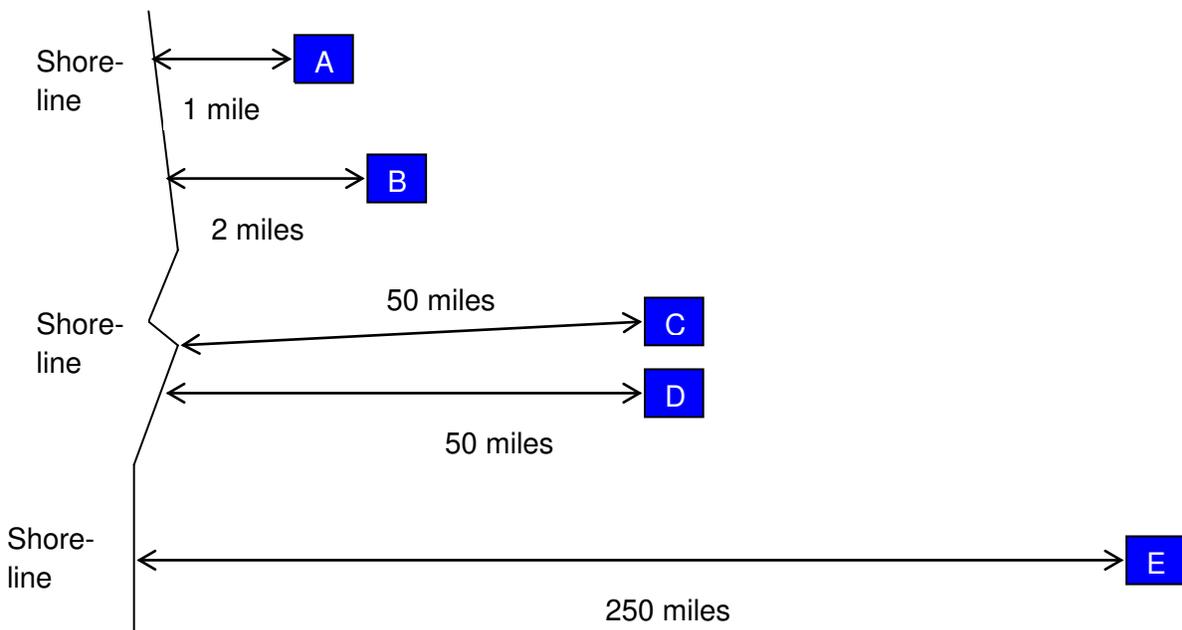
<sup>4</sup> Exceptions to the 3.45-mile limit apply to Texas and to the Florida Gulf coast, where state waters extend to three marine leagues (approximately 10.5 statute miles).

<sup>5</sup> The continental margin comprises the prolongation of the land mass of a coastal state submerged under relatively shallow water, and consists of the seabed and subsoil of the shelf, as well as the slope and the rise connecting the shallow shelf to the deep ocean floor. The continental margin ends where the deep ocean floor begins.

miles from California's shore. Finally, the fifth platform (platform E) is located in deep water beyond the limits of the continental margin 250 miles from California's shoreline.

In this example, ACME Oil should report the GHG emissions from A and B as California emissions, and report the emissions from offshore platforms C and D as U.S. emissions. ACME Oil is not required to report emissions from platform E, as this platform lies in international waters. However, ACME Oil does have the *option* to report emissions from platform E as part of its global emissions report (see Chapter 2 of the GRP).

**Figure 2.1 – Jurisdictional Boundaries of Offshore Oil Platforms**



## 2.2 Optional Reporting: Non-North American Emissions

REFER TO GRP.

## Chapter 3: Gases to Be Reported

REFER TO GRP.



## Chapter 4: Organizational Boundaries

### 4.1 Two Approaches to Organizational Boundaries

The GRP provides two main options for defining organizational boundaries:

- **Option 1:** Reporting GHG emissions based on both a control approach and the equity share approach; or
- **Option 2:** Reporting GHG emissions based exclusively on a control approach (with equity information).

Please refer to the GRP for a basic definition and explanation of these two consolidation methodologies. Sections 4.2.1 and 4.3.1 below provide examples on how to apply these options to situations common in the O&GP sector.

### 4.2 Option 1: Reporting Based on Both Equity Share and Control

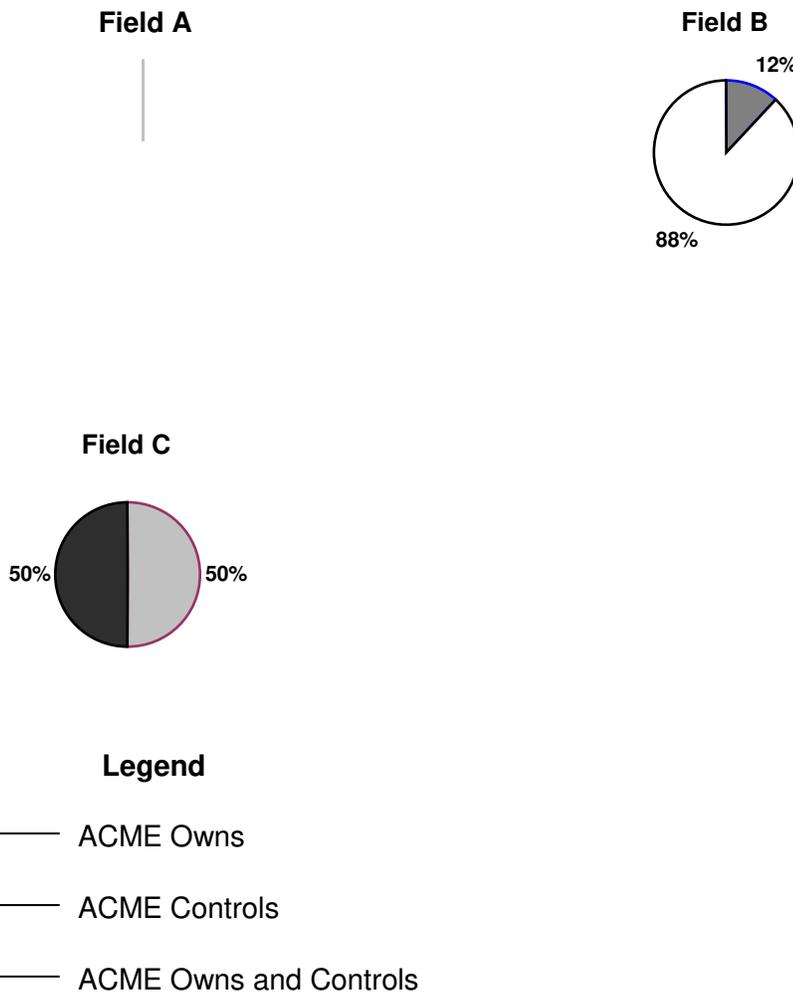
Under the control approach, you are required to report 100 percent of the emissions from sources under their control, including both wholly owned and partially owned sources. To ensure reporting consistency across Members' GHG inventories, The Registry requires Members to report their emissions based on the control approach at a minimum.

Under Option 1 (reporting based on *both* equity share and control), in addition to reporting based on the control approach, you also report your emissions based on their equity share of sources that may or may not be within your direct control.

#### 4.2.1 Example: Reporting Based on Both Equity Share and Control

ACME Oil Company is currently producing oil in three separate production fields scattered throughout North America. ACME wholly owns and controls its production operations in Production Field A, while it has a 12 percent ownership stake in the operation controlled by Best Oil Company on behalf of a consortium of companies in Production Field B. As a partner of Best Oil Company with a 50 percent stake in a joint venture, ACME controls the drilling and production operations in Production Field C. ACME's ownership and control of each of the three production fields is depicted in Figure 4.1.

**Figure 4.1 – ACME Oil Company’s Production Field Relationships**



When reporting to The Registry using the control consolidation methodology, ACME must report all of the emissions from its operations in Production Field A, as well as all of the emissions from the joint venture in Production Field C because ACME controls the operations in these two production fields.

However, if ACME chooses to additionally develop an equity share emission report (Option 1), their report would include 100 percent of the emissions from Production Field A, 12 percent of the emissions from Production Field B and 50 percent of the emissions from Production Field C.

Table 4.1 illustrates ACME’s Registry reporting responsibilities under Option 1.

**Table 4.1 – ACME Oil Company’s Reporting Responsibilities Under Option 1**

Operation	ACME’s Ownership Stake	Does ACME Control the Operation?	ACME’s Reporting Responsibilities Under:	
			Equity Share	Operational Control
Field A	100% Wholly-Owned	Yes	100% of Emissions	100% of Emissions
Field B	12% of Consortium	No	12% of Emissions	No Reporting Responsibility
Field C	50% of Joint Venture (Partnership)	Yes	50% of Emissions	100% of Emissions

### 4.3 Option 2: Reporting Based on Control

The GRP provides two different options for defining “control.” The two options are as follows:

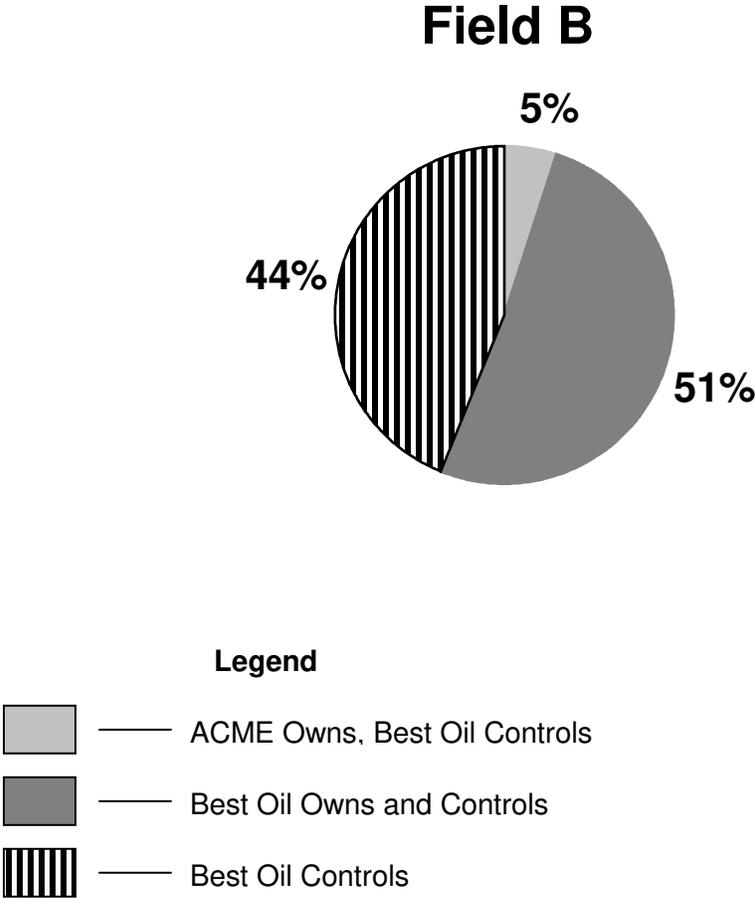
- Operational Control:** Defined as the full authority to introduce and implement operating, health, safety, and environmental policies. Typically the entity that holds the operating license for an operation has operational control. In the case of the O&GP sector, the entity with the authority to decide matters such as where and when to drill has operational control.
- Financial Control:** Defined as the ability to direct the financial policies of the operation with an interest in gaining economic benefits from its activities. Typically the entity holding the majority of the financial risks and benefits in an operation exercises financial control over the operation. Specifically, a Member has financial control over an operation or subsidiary if the operation is fully consolidated in the Member’s financial statements. Thus, the activities of a wholly-owned subsidiary of an oil company would be reported by the oil company if the company chose to report based on financial control.

The Registry strongly recommends that Members with operations in the O&GP sector report using the operational control method, as it is generally the most straightforward approach to defining organizational boundaries for this sector.

#### 4.3.1 Example: Determining Financial Control of a Consortium

ACME owns five percent of a consortium formed to develop the oil reserves in Production Field B. Best Oil owns 51 percent of the consortium. As the majority owner, Best Oil has financial control of the consortium. ACME’s and Best Oil’s relationships to Production Field B are depicted in Figure 4.2.

Figure 4.2 – ACME and Best Oil’s Field B Control Relationships



In this scenario, Best Oil must report 100 percent of the emissions from Production Field B if it chooses to use the financial control consolidation methodology.

ACME, on the other hand, would not report any emissions from the consortium under the financial control option, despite its five percent ownership stake, because it does not have any financial control over the consortium. Under the financial control consolidation approach, an entity is required to report its equity share of an operation *only* if it has financial control over the financial policies of a consortium or joint venture.

**Table 4.2 – Determining Financial Control for Two Members of a Consortium**

Item	ACME	Best Oil
<b>Ownership and Control of Production Field B Consortium</b>		
Percent Ownership	5%	51%
Financial Control?	No	Yes

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#### 4.3.2 Example: Responsibilities of O&GP Leaseholders and Contractors

ABC Oil Company holds a lease to produce all oil in the Big Strike Field. ABC has a contract with Diamond Drilling to perform all of ABC’s drilling operations. All of the drill rigs used in the field are owned, and fully controlled, by Diamond Drilling. All production activities in the field besides drilling are conducted directly by ABC.

Under either of the control consolidation approaches, ABC is required to report GHG emissions from all sources in the Big Strike Field, except for the emissions from the drilling rigs. Specifically, ABC would be responsible for reporting all venting and flaring emissions from the wells, in addition to emissions from all non-drilling equipment located in the field (e.g., pipeline compressors, mobile equipment such as supply trucks, bulldozers, front-end loaders, etc., and stationary combustion devices such as electricity generators, engines, etc.).

ABC would *not* be responsible for reporting emissions from Diamond Drilling’s rigs (although ABC has the *option* of reporting these emissions as its scope 3 emissions--see Chapter 5 for a definition of the various reporting scopes). Diamond Drilling must report the emissions resulting from the drill rigs, because the rigs are owned and fully controlled (operationally and financially) by Diamond Drilling.

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#### 4.4 Corporate Reporting: Parent Companies & Subsidiaries

REFER TO GRP.

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#### 4.5 Government Agency Reporting

REFER TO GRP.

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## 4.6 Leased Assets

The treatment of a leased asset parallels that of owned assets, and depends on the type of lease governing control of the asset. The GRP identifies the two main types of leases: operating leases and finance or capital leases.<sup>6</sup>

All emissions from assets leased under a finance or capital lease must be reported by the lessee regardless of whether the operational or financial control approach is being used. Such leases grant the lessee both operational and financial control of the asset. In contrast, emissions from assets covered by an operating lease must be reported by the lessee only when the lessee is using the operational control consolidation approach.

In the O&GP sector, mineral rights are often leased. Reporting emissions can become complicated when hydrocarbons are emitted from leased mineral rights. For example, when a leaseholder vents or flares a portion of the gas under lease as part of the normal production process, reporting the GHGs associated with venting, leakage and flaring will generally be the leaseholder's responsibility since the lease gives the leaseholder control of the *source* of the emissions (i.e., the mineral rights). However, there are exceptions to this general rule, particularly overseas.

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## 4.7 Examples of Control versus Equity Share Reporting

The O&GP sector is often characterized by complex, multi-layered ownership and leasing patterns. The following examples are provided to clarify how The Registry's reporting rules should be applied to these complex arrangements.

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### 4.7.1 Example: Reporting Responsibilities of Shareholders in a Consortium

Alpha Oil Co. holds a 60 percent equity share of a consortium. Beta Oil Corp has 25 percent equity share in the consortium. Alpha operates the consortium and leases equipment from Beta Oil Corp, under an operating lease. Alpha Oil Co. and Beta Oil Corp's reporting responsibilities are displayed in Table 4.7.

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<sup>6</sup> The terms "finance lease" and "capital lease" are not often used in the O&GP sector; however, it fits the leasing arrangements where a landowner leases both the operational rights and mineral rights in exchange for a stream of royalty payments.

**Table 4.3 – Reporting Responsibilities of Alpha Co. and Beta Oil Corp**

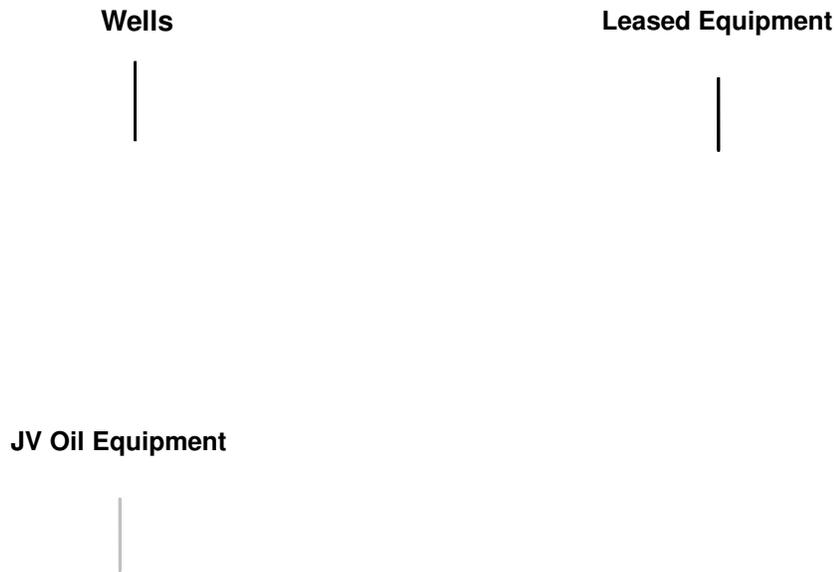
Consortium Partner	Ownership Stake in Consortium	Operational Control of Consortium’s Operations?	Financial Control of Consortium’s Operations?	Reporting Responsibilities Under:		
				Operational Control	Financial Control	Equity Share
Alpha Oil Co.	60%	Yes	Yes	100%	100% (excluding emissions from leased assets from Beta)	60%
Beta Oil Corp.	25%	No	No	0%	Emissions from equipment leased to Alpha	25%

Under the financial control and equity share option, Alpha must assess its financial control relationship to each individual emitting source. Alpha has financial control over the consortium, and therefore must report 100 percent of the consortium’s emissions. However, Alpha does *not* have financial control over the leased equipment because this equipment has been transferred to the consortium under the terms of an *operating* lease; financial control thus remains with the equipment owner (Beta Oil Corp).

**4.7.2 Example: Consortium Operated by a Separate Company**

Assume that the consortium shareholders in the previous example created a jointly-owned separate operating company. The operating company, JV Oil Corporation, is granted operational control over the consortium’s activities, but financial control remains with Alpha (given its 60 percent equity share). JV Oil has no input on financial decisions, nor does it have an equity share in the consortium; it is strictly an operating company. In addition to using its own equipment, JV Oil leases equipment from another (non-consortium member) company. JV Oil’s control relationship to each set of assets is depicted in Figure 4.3.

**Figure 4.3 – JV Oil’s Control Relationships to Individual Consortium Assets, and Its Equity Share of the Consortium**



**Legend**

- — Assets over which JV Oil has Operational Control Only
- — Assets Owned and Controlled by JV Oil

JV Oil’s reporting responsibilities are shown in Table 4.8. As the consortium operator, JV Oil is responsible for reporting 100 percent of the emissions from all sources under its operational control. As Figure 4.3 indicates, JV Oil has operational control over all of the individual sets of assets, and thus would be responsible for reporting 100 percent of the emissions from all assets under the operational control consolidation methodology.

In contrast, JV Oil would not be responsible for reporting the emissions from any sources under the financial control consolidation methodology, *except* for the emissions from the equipment directly owned by JV Oil. Here, even though JV Oil does not have financial control over the consortium, it still has financial control over its own equipment—and under the control options, reporting responsibilities must be determined based on control over each individual emitting source comprising the consortium. Since JV Oil’s equity share in the consortium is zero, it would not be required to report any emissions under the equity share approach from those sources outside its financial control.

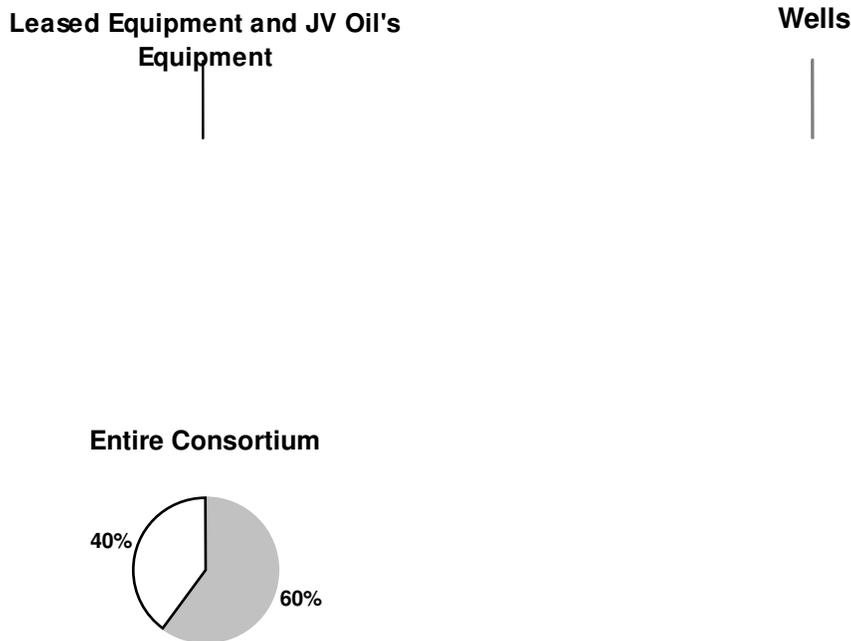
**Table 4.4 – JV Oil’s Reporting Responsibilities**

Consolidation Methodology	Emission Sources		
	Wells	JV Oil’s Equipment	Leased Equipment
Operational Control	100%	100%	100%
Financial Control	0%	100%	0%
Equity Share	0%	100%	0%

**4.7.3 Example: Reporting Responsibilities of a Consortium Majority Shareholder**

Continuing with the example in Section 4.7.2, let’s consider the reporting responsibilities of Alpha, who has financial, but not operational, control. Figure 4.4 shows Alpha’s control relationships to individual consortium assets, as well as its equity share in the consortium.

**Figure 4.4 – Alpha’s Control Relationships to Individual Consortium Assets, and Its Equity Share of the Consortium**



### Legend

-  — Assets over which Alpha has Financial Control
-  — Assets over which Alpha has neither Operational
-  — Alpha's Equity Share of the Consortium

Table 4.5 shows Alpha's reporting responsibilities. As Figure 4.4 indicates, Alpha does not have operational control over any of the consortium's assets. Therefore, under the operational control consolidation method, Alpha is not responsible for reporting any of the consortium's emissions. Under the financial control consolidation methodology, Alpha is responsible for reporting 100 percent of the emissions from the wells. Finally, using the equity share consolidation methodology, Alpha is responsible for reporting 60 percent of the emissions from the wells.

**Table 4.5 – Reporting Responsibilities for Alpha**

Consolidation Methodology	Emission Sources		
	Wells	JV Oil's Equipment	Leased Equipment
Operational Control	0%	0%	0%
Financial Control	100%	0%	0%
Equity Share	60%	0%	0%

## Chapter 5: Operational Boundaries

### 5.1 Required Emission Reporting

As stated in the GRP, The Registry requires Members to report scope 1 and scope 2 emissions. Section 5.2 below describes the scope 1 sources specific to the O&GP sector. Section 5.3 describes the relevant scope 2 emission sources for this sector. Reporting scope 3 emissions is optional. Section 5.5 provides some examples of scope 3 emission sources specific to the O&GP sector.

CO<sub>2</sub> emissions from the stationary combustion of biomass are not categorized by scope. Rather, these emissions must be reported separately from scope 1 and scope 2 emissions.

### 5.2 Direct Emissions: Scope 1

Direct (scope 1) emissions are emissions from sources within your organizational boundaries. The GRP requires that you report all of your scope 1 emissions. For oil and gas leaseholders, scope 1 emissions will generally include process emissions from oil and gas wells, in addition to combustion, fugitive, and process emissions from stationary and mobile equipment inside the leaseholder's organizational boundary (see Chapter 4 of the O&GP Protocol and Chapter 4 of the GRP for more information on organizational boundaries).

While the GRP provides quantification methodologies for many scope 1 emission sources, the O&GP sector includes some unique sources which are not addressed in the GRP, such as, venting and flaring emissions from wells and specialized equipment. GHG emission quantification methodologies for sources unique to this sector are provided in Part III, Chapters 12 through 17, of this O&GP Protocol.

Please refer to Chapter 5 of the GRP for more information on scope 1 emissions.

### 5.3 Indirect Emissions: Scope 2

Indirect scope 2 emissions are emissions that are a consequence of activities that take place within your organizational boundary, but which occur at sources owned or controlled by another organization. Scope 2 emissions are a special category of indirect emissions consisting exclusively of those emissions associated with the consumption of purchased or acquired electricity, steam, heating, or cooling. For oil and gas leaseholders, an example of scope 2 emissions are emissions associated with outside suppliers of electricity and steam.

The O&GP sector does not contain any unique scope 2 emission sources. Please refer to Chapter 5 of the GRP for more information on indirect scope 2 emissions. Refer to Chapters 14

and/or 15 of the GRP for specific quantification methodologies related to calculating scope 2 emissions.

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#### 5.4 Reporting Emissions from Biomass Combustion

REFER TO GRP.

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#### 5.5 Scope 3 Emissions

Scope 3 emissions are defined as all indirect emissions *not* included in scope 2. The Registry encourages you to report scope 3 emissions, but does not require these emissions to be reported. Examples of scope 3 emissions that Members with O&GP operations may *opt* to report include:

- Contractor emissions associated with drilling, completions, and workovers, as well as ancillary support services such as general maintenance;
- Emissions from gathering lines, when lines are owned and controlled by other companies;
- Contracted transportation of equipment, personnel and supplies to and from the production;
- Upstream emissions from the disposal of waste generated during the O&GP process.
- Downstream emissions from the refining of sold crude oil;
- Downstream emissions from the transmission and distribution of sold natural gas; and
- Downstream emissions from the combustion of sold natural gas and/or petroleum products.

## Chapter 6: Facility-Level Reporting

### 6.1 Required Facility-Level Reporting

REFER TO GRP.

### 6.2 Defining Facility Boundaries

The Registry requires you to report your emissions at the facility level. Specifically, you must report your emissions by type of source (stationary combustion, mobile combustion, process, fugitive and indirect) and gas (CO<sub>2</sub>, CH<sub>4</sub>, N<sub>2</sub>O, HFCs, PFCs and SF<sub>6</sub>) within each facility.

However, as noted in the GRP, some emission sources cannot be easily associated with a traditionally defined facility (i.e., a “single physical premise”). Several emission sources within the O&GP sector are prime examples of sources that cannot easily be distinguished or grouped using the standard definition of a facility.<sup>7</sup> Instead, operations within the O&GP sector are typically characterized by hundreds, or even thousands, of very small sources that spread out over the area of operation. This makes reporting emissions at a facility level burdensome.

#### Oil and Gas Production Installations

In recognition of the unique geographic realities in the O&GP sector, you may report emissions from distributed sources according to self-defined “Oil and Gas Production Installations.” At a minimum, installations must consist of all distributed stationary emission sources located within an oil or gas production field. Grouping emission sources to form an installation mirrors the concept of grouping multiple emission sources into a traditional “facility.” In the case of an installation, the installation is not defined by physical borders (a building), but rather geographic ones (the area of the production field).

You may define an Oil and Gas Production Installation as the emissions from either a single field or multiple fields as long as all of the fields included in a single installation fall within the boundaries of a single state or province. For example, a Member with emissions from wells and other geographically distributed sources such as compressor and booster stations in Production Fields A, B, and C, all located in Texas, may choose to aggregate and report these emissions separately for each production field, or they may report the emissions as a single aggregated Oil and Gas Production Installation which combines the emissions from all three production fields.

Each nation, state or province/territory in North America has named and delineated the specific oil and gas production fields under its jurisdiction. Production fields are defined by only one entity. U.S. states and Canadian provinces have jurisdiction to define production fields, whereas

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<sup>7</sup> In general, a facility is defined as a single physical premises. Regulatory programs often define a facility as any stationary installation or establishment located on a single site or on contiguous or adjacent sites that are owned or operated by an entity. The Registry uses this definition for stationary sources as well.

Mexico defines production fields nationally. Specific production field designations are provided in all well drilling permits.

Member-defined Oil and Gas Production Installations may not cross sub-national or national boundaries. Emissions from production fields that cross state, provincial, or national boundaries must be disaggregated and reported separately for each jurisdiction within the production field. A production field that straddles two jurisdictions must be reported as two separate production fields, for example, Production field A – Texas and Production Field A – Oklahoma.

Emissions from your organization's wells and associated production equipment must be reported as Oil & Gas Production Installations. Processing plants, natural gas processing plants, refineries, and other facilities that conform to the traditional definition of a facility must be reported as separate, individual facilities in accordance with the general instructions for facility-level reporting provided in the GRP, even when these facilities lie within the geographic boundaries of a production field.

The reporting requirements for Oil and Gas Production Installations are the same as for standard facilities. Within each Oil and Gas Production Installation or standard facility, you must separately total emissions by source categories (stationary combustion, mobile combustion, process, fugitive, and indirect) and gas.

Emissions from mobile sources are a special case; these emissions are discussed in Section 6.4.

### Pipelines

Pipelines are often used to transport produced natural gas to the custody transfer point and crude oil from producing fields to refineries. Pipelines sometimes extend over long distances, and may in some cases cross state, provincial, or even national boundaries. As described in Section 6.2 of the GRP, you should treat each pipeline or pipeline system as a single facility, unless the pipeline crosses a state/provincial or national boundary. If it is possible to separately account for the emissions located in each jurisdiction, you should subdivide the pipeline/pipeline system into two separate facilities along the jurisdictional boundary.

If it is not possible to separately account for emissions by jurisdiction, the pipeline/pipeline system may be treated as a single facility and may be reported at the national or North American level.<sup>8</sup> The following examples explain how you can report emissions from pipelines used to transport crude oil from producing fields to refineries.

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<sup>8</sup> Facilities should be reported at the national level when they cross state or provincial lines but do not cross national jurisdictions. Facilities should be reported at the North American level when pipelines cross national jurisdiction boundaries within North America.

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## 6.2.2 Example: Potential Facility Definitions for a Crude Oil Pipeline

### Scenario 1

A pipeline transports crude oil 50 miles from a producing oil field in Texas to a refinery in Louisiana. The operator of the pipeline is a member of The Registry. Although the operator has data on the total energy used to operate the pipeline, it does not have this data broken down for each pipeline segment by state. Because the operator lacks the data necessary to calculate separate emissions estimates for the Louisiana and Texas segments of the pipeline, the pipeline should be treated as one “aggregated facility” for reporting purposes. Rather than assigning this facility to a specific state, it should be assigned to the U.S. country category (without specifying a state-level assignment).

### Scenario 2

An oil pipeline transports crude oil from a field in Alberta, Canada, through Saskatchewan and Manitoba, to a refinery outside Minneapolis, Minnesota. The pipeline operator has detailed energy/emissions data for each pumping station along the line. In this case, the data necessary to estimate emissions for each provincial/state pipeline segment is available. Therefore, following the rules established in the GRP, the pipeline should be treated as four separate facilities for reporting purposes: an Alberta facility, a Saskatchewan facility, a Manitoba facility, and a Minnesota facility. Emissions should be calculated and reported separately for each of these four pipeline segments.

If in this example data were available to enable a partial but not a full subdivision of the pipeline along jurisdictional boundaries, the pipeline should be subdivided to the extent enabled by the available data. For example, if you had separate energy/emissions data by country but not by state or province, you should subdivide and report the pipeline emissions by country (a Canadian facility and a U.S. facility). Please refer to Section 6.2 of the GRP for more information on the required aggregation and disaggregation of pipeline emissions.

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## 6.3 Optional Aggregation of Emissions from Certain Types of Facilities

REFER TO GRP.

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## 6.4 Categorizing Mobile Source Emissions

The GRP makes a distinction between ground-based mobile sources that operate exclusively within a single facility (such as forklifts) and ground-based mobile sources that operate at least some of the time beyond the borders of a single facility (such as trucks and cars). You should report mobile sources that remain within a facility as one or many mobile combustion sources within the facility. You may aggregate and report mobile combustion sources that travel outside of your facility or Oil and Gas Production Installation boundaries according to the aggregation rules specified in Chapter 6 of the GRP (by state, province/territory, or country).

Specifically, you must report mobile emission sources that operate *exclusively* within the boundaries of a single Oil and Gas Production Installation during a given reporting year as part of that installation's emissions.

You should not assign mobile emission sources that travel beyond the boundaries of a single Oil and Gas Production Installation during the reporting year to any particular installation or facility for reporting purposes. Rather, you should report these emissions separately. For example, dedicated vessels and helicopters that serve offshore platforms should *not* be included in the emissions for the offshore production field, because these vessels travel beyond the boundaries of the production field (e.g., when they return to shore). Hence, you should report the emissions from the vessels and helicopters separate from your Oil and Gas Production Installation emissions (as Marine and Air based fleets, respectively).

Please see Chapter 6 of the GRP for additional information about aggregating and reporting emissions from mobile sources.

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#### 6.5 Optional Reporting: Unit Level Data

REFER TO GRP.

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#### 6.6. Aggregation of Data to Entity Level

REFER TO GRP.

## **Chapter 7: Establishing and Updating the Base Year**

REFER TO GRP.

## **Chapter 8: Transitional Reporting (Optional)**

REFER TO GRP.

## Chapter 9: Historical Reporting (Optional)

REFER TO GRP.

## PART III: QUANTIFYING YOUR EMISSIONS

### Chapter 10: Introduction to Quantifying Your Emissions

The GRP contains methodologies for estimating emissions from stationary combustion, mobile combustion, electricity use, imported steam, and refrigeration and air conditioning equipment. These methodologies apply to many of the emission sources found in the O&GP sector, such as mobile equipment and stationary engines, boilers, steam generators, gas turbines, imported electricity and steam, etc. However, the O&GP sector also includes many emissions sources that are not covered in the GRP. These unique sources produce process and fugitive emissions (from venting, flaring, and leakage) associated with O&GP activities.

Part III (Quantifying Your Emissions) of the O&GP Protocol contains calculation methodologies for these unique sector sources.

Please note that many of the quantification methodologies in Part III rely on default emission factors that may not adequately take into account unique conditions at specific sites. This is a special risk on the O&GP sector due to the inherent variability in fuel composition during the exploration and production process. For this reason, although all methodologies in this protocol that are not specifically designated as simplified estimation methods are accepted Registry methodologies, The Registry encourages you to use measured site specific data to generate site-specific emission factors whenever possible.

Table 10.1 below contains a list of the emission sources found in the O&GP sector and the document (GRP or O&GP Protocol) and chapter(s) containing Registry-approved quantification methodologies for each source.

For additional information on quantifying your emissions, please refer to Chapter 10 of the GRP.

**Table 10.1 – Cross Reference of Oil and Gas Source Categories**

<b>Source Category</b>	<b>Refer to:</b>
<b>Stationary Combustion Emissions (Chapter 12):</b>	
Artificial lift engines (pumpjacks)	GRP, Chapter 12
Well testing and completion activities (non-venting)	GRP, Chapters 12-15
Vapor recovery unit (VRU) engines	GRP, Chapter 12
Heaters	GRP, Chapter 12
Boilers	GRP, Chapter 12
Cogeneration units (EOR)	GRP, Chapter 12
Miscellaneous I.C. engines	GRP, Chapters 12 and 13
Salt-water disposal (SWD) engines	GRP, Chapter 12
Flares/incinerators	O&GP, Chapter 12
Central power plant turbines (offshore)	GRP, Chapter 12
Central power plant I.C. engines (offshore)	GRP, Chapter 12

<b>Source Category</b>	<b>Refer to:</b>
Lateral/wellhead compressor engines	GRP, Chapter 12
Boilers/steam generators	GRP, Chapter 12
Gas turbines	GRP, Chapter 12
CBM pump engines	GRP, Chapter 12
<b>Mobile Combustion Emissions (Chapter 13):</b>	
Exploratory drilling engines	GRP, Chapter 13
Well testing and completion activities (non-venting)	GRP, Chapters 12-15
Drill rig engines	GRP, Chapter 13
Workover rig engines	GRP, Chapter 13
Miscellaneous I.C. engines	GRP, Chapters 12 and 13
Heavy-duty trucks	GRP, Chapter 13
Medium-duty trucks	GRP, Chapter 13
Light-duty trucks	GRP, Chapter 13
Light-duty automobiles	GRP, Chapter 13
Offshore support and seismic vessels (OSV)	GRP, Chapter 13
Helicopters (offshore)	GRP, Chapter 13
Converted diesel ship engines (offshore)	GRP, Chapter 13
Haulers and dump trucks	GRP, Chapter 13
Bulldozers	GRP, Chapter 13
Scrapers	GRP, Chapter 13
Blasthole drills	GRP, Chapter 13
Explosive loading trucks	GRP, Chapter 13
Front end loaders	GRP, Chapter 13
Hydraulic excavators	GRP, Chapter 13
Mobile cranes, forklifts, maintenance and supply trucks, road graders, etc.	GRP, Chapter 13
<b>Indirect Emissions from Electricity (Chapter 14)</b>	
Imported electricity	GRP, Chapter 14
<b>Indirect Emissions from Imported Steam and Heating (Chapter 15)</b>	
Process heat/steam imports	GRP, Chapter 15
<b>Fugitive Emissions (Chapter 16):</b>	
Chemical injection pumps	O&GP, Chapter 16
Oil well fugitives	O&GP, Chapter 16
Gas well fugitives	O&GP, Chapter 16
Gas pipeline fugitives	O&GP, Chapter 16
Water treatment facilities (evaporative ponds)	O&GP, Chapter 16
<b>Process Emissions (Chapter 17):</b>	
Well testing and completion venting	O&GP, Chapter 17
Drill mud degassing	O&GP, Chapter 17
Glycol dehydrators	O&GP, Chapter 17
Oil well truck loading	O&GP, Chapter 17
Tankers in floating production, storage, and offloading systems – FPSO (Offshore)	O&GP, Chapter 17
Coke gasification unit	O&GP, Chapter 17
Hydrogen production unit	O&GP, Chapter 17
Primary upgrading coke unit	O&GP, Chapter 17

<b>Source Category</b>	<b>Refer to:</b>
Gas well and natural gas liquid plant truck loading	O&GP, Chapter 17
Well blowdowns	O&GP, Chapter 17
Compressor blowdowns	O&GP, Chapter 17
Gas well and plant truck loading	O&GP, Chapter 17
Acid gas removal systems	O&GP, Chapter 17
Vessel blowdowns	O&GP, Chapter 17
Pipeline blowdowns	O&GP, Chapter 17
Oil well tanks	O&GP, Chapter 17
Gas well condensate tanks	O&GP, Chapter 17
Compressor start-ups and shutdowns	O&GP, Chapter 17
Gas processing plant fugitives	O&GP, Chapter 17
Pneumatic devices	O&GP, Chapter 17
Gas actuated pumps	O&GP, Chapter 17

## Chapter 11: Simplified Estimation Methods

REFER TO GRP.

## Chapter 12: Direct Emissions from Stationary Combustion

The GRP contains emission calculation methodologies covering most stationary combustion devices and fuels. This chapter of the O&GP contains quantification methodologies for emissions from combustion devices and fuel types unique to the O&GP sector, including, hydrogen units and coker upgraders. Whenever possible, you should use site-specific information about combustion devices and fuel composition<sup>9</sup> to ensure the most accurate GHG emissions inventory possible. This chapter also contains alternative methodologies for stationary combustion devices for which fuel consumption data is lacking.

Table 12.1 lists the quantification methods described in this chapter along with each method's data requirements.

**Table 12.1 – Summary of Calculation Methods for Stationary Combustion Emissions**

Method	Data Requirements
O&GP ST-01	Rated Horsepower, Load factor, Emissions factors for CO <sub>2</sub> , CH <sub>4</sub> , and N <sub>2</sub> O, Annual hours of operation
O&GP ST-02	Rated Capacity (MW), Heat Rate (Btu/kWh), Emissions factors for CO <sub>2</sub> , CH <sub>4</sub> , and N <sub>2</sub> O, Annual hours of operation
O&GP ST-03	Rated Horsepower, Load factor, Heat Rate (Btu/kWh), Brake-specific fuel consumption (lb-fuel/hp-hr), HHV (Btu/lb), Emissions factors for CO <sub>2</sub> , CH <sub>4</sub> , and N <sub>2</sub> O, Annual hours of operation
O&GP ST-04	Nameplate firing capacity (MMBtu/hr), HHV (MMBtu/scf), Emissions factors for CO <sub>2</sub> , CH <sub>4</sub> , and N <sub>2</sub> O, Annual hours of operation
O&GP ST-05	Site-specific mass balance approach
O&GP ST-06	Flare inlet gas volume, Molecular weight of Natural Gas, Mass fraction of carbon in the fuel, Fraction of fuel carbon oxidized, Combustion efficiency of the flare, Molecular weight of CH <sub>4</sub> , Molecular weight of CO <sub>2</sub> , Molar conversion factors
O&GP ST-07	Flare inlet gas volume, Emission factor of CH <sub>4</sub> , CO <sub>2</sub> and N <sub>2</sub> O
O&GP ST-08	Flaring events, Flare inlet gas volume, Flare combustion efficiency

### 12.1 Measurement Using Continuous Emissions Monitoring System Data

REFER TO GRP.

### 12.2 Calculating Emissions from Stationary Combustion Using Fuel Use Data

The GRP contains a number of quantification methodologies for emissions from stationary combustion devices that are based on fuel consumption data. You should use the

<sup>9</sup> Fuel composition data is particularly important when reporting field gas or lease fuel, as the composition of these gasses can vary widely.

methodologies provided in the GRP to calculate emissions for stationary combustion devices for which you have fuel consumption data. If you do not have fuel consumption data for some stationary combustion devices, please refer to Section 12.4 of this O&GP protocol for emissions calculation guidance.

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### 12.3 Allocating Emissions from Combined Heat and Power (Optional)

REFER TO GRP.

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### 12.4 Calculating Emissions for Unmetered Stationary Combustion Devices

The O&GP sector utilizes stationary combustion devices—particularly smaller compression engines and natural gas turbines—that are not metered for fuel consumption. The Registry requires you to use the following methodologies to calculate emissions for stationary combustion devices without fuel consumption data. These methodologies utilize the load factor of the combustion device and the device’s rated capacity and hours of operation as the basis for calculating emissions.

In order to use these methodologies, The Registry requires that, at a minimum, you either:

- 1) Meter the operating hours of the combustion devices, or
- 2) Assume that the devices operate on a continuous (24 hour/day) basis.

If operation hours are not metered, you must assume continuous, 24 hour/day, 365 day/year operation in order to provide a conservative estimate of the devices’ emissions. Metered operation hours must include *all* hours during which a device is in operation, regardless of whether it was running in standby or full load mode.

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#### O&GP ST-01:

#### CALCULATING EMISSIONS FROM UNMETERED COMPRESSOR ENGINES AND NATURAL GAS TURBINE COMPRESSORS USING A LOAD FACTOR

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The following equation may be used to estimate emissions from compressors using either reciprocating internal combustion engines or natural gas turbines for which fuel consumption data are lacking.

**Equation 12a: Calculating Emissions from Compressors Using a Load Factor<sup>10</sup>**

$$E = HP \times LF \times f_e \times EF \times t_{annual}$$

where:

$E$  = the annual emissions of CO<sub>2</sub>, CH<sub>4</sub>, or N<sub>2</sub>O per engine or turbine [t/yr]

$HP$  = the rated horsepower of the engine or turbine [hp]

$LF$  = the load factor of the engine or turbine

$f_e$ , the energy-basis conversion factor for the engine (you must use data available from the manufacturer; if data are not available from the manufacturer you may use the default values of 0.007858 for a natural gas internal combustion engine or 0.010379 for a natural gas turbine [MMBtu/hp-hr]<sup>11</sup>)

$EF$  = the CO<sub>2</sub>, CH<sub>4</sub>, or N<sub>2</sub>O emission factor from Chapter 12 of the GRP on an energy basis [t/MMBtu]

$t_{annual}$  = the actual annual hours of usage of the engine (hr/yr)

The value of the load factor (LF) in the equation should be based on compressor-specific data or engineering estimates (derived from production field pressures) whenever possible. However, when compressor-specific data or engineering estimates are not available, a default value of 0.75 may be used for the load factor<sup>12</sup>.

<sup>10</sup> API 2009. "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry," Prepared for American Petroleum Institute (API), Prepared by URS Corp., August 2009.

<sup>11</sup> WRAP, 2009. "Oil and Gas Exploration and Production Greenhouse Gas Protocol, Task 2 Report: Significant Source Categories and Technical Review of Estimation Methodologies," Prepared for Western Regional Air Partnership, Prepared by ENVIRON International Corp. and Science Applications International Corp., April 2009.

<sup>12</sup> WRAP, 2005. "Oil and Gas Emission Inventories for the Western States," Prepared for the Western Governor's Association, Prepared by ENVIRON International Corp., December 2005. WRAP, 2007. "WRAP Area Source Emissions Inventory Projections and Control Strategy Evaluation, Phase II," Prepared for Western Governor's Association, Prepared by ENVIRON International Corp., September 2007. WRAP, 2008. "Joint Rocky Mountain Phase III Oil and Gas Emissions Inventory Project," Prepared for Independent Petroleum Association of Mountain States (IPAMS) and Western Governor's Association, Prepared by ENVIRON International Corp. and Buys and Associates Inc., July 2008. Internet address: <http://wrapair.org/forums/ogwg/Phase III Inventory.html>.

## CALCULATING EMISSIONS FROM UNMETERED NATURAL GAS TURBINE GENERATORS USING A LOAD FACTOR

Natural gas turbines are also sometimes used to drive electricity generators in the O&GP sector. For example, natural gas turbines are often used to supply electricity to offshore platforms. You should use the methodologies provided in Chapter 12 of the GRP to calculate emissions from all gas turbine generators for which fuel consumption data are available. However, the following equation may be used when fuel consumption is not metered.

### Equation 12b: Calculating Emissions from Natural Gas Turbine Generators Using a Load Factor

$$E = (P \times HR \times EF \times t_{annual}) / 1000$$

where:

$E$  = the annual emissions of CO<sub>2</sub>, CH<sub>4</sub>, or N<sub>2</sub>O per turbine (t/yr)

$P$  = the rated capacity of the turbine (MW)

$HR$  = the heat rate of the turbine (Btu/kWh) (If the turbine's heat rate is unknown, please refer to Table 12.2 for default heat rates)

$EF$  = the emissions factor of CO<sub>2</sub>, CH<sub>4</sub>, or N<sub>2</sub>O from Chapter 12 of the GRP on an energy basis (t/MMBtu)

$t_{annual}$  = the actual annual hours of usage of the turbine (hr/yr)

**Table 12.2 – Default Heat Rates by Generator Type**

Generator Type	Fuel Type	Original Units	Converted Units	
		Btu/kW-hr	Btu/hp-hr	J input/ J output
Advanced Combustion Turbine	Not Specified	9,289	6,927	2.722
Advanced Gas/Oil Combined Cycle	Not Specified	6,752	5,035	1.979
Advanced Gas/Oil Combined Cycle with Carbon Sequestration	Not Specified	8,613	6,423	2.524
Biomass	Not Specified	8,911	6,645	2.612
Combined Heat and Power	Natural Gas	5,000-6,000	3,729 – 4,474	1.465 – 1.758
Combined Cycle Single Shaft	Natural Gas	8,952	6,676	2.624
Combined Cycle Steam Turbine with Supplemental Firing	Natural Gas	10,229	7,628	2.998

Generator Type	Fuel Type	Original Units	Converted Units	
		Btu/kW-hr	Btu/hp-hr	J input/ J output
Conventional Combustion Turbine	Not Specified	10,833	8,078	3.175
Conventional Gas/Oil Combined Cycle	Not Specified	7,196	5,366	2.109
Distributed Generation – Baseload	Not Specified	9,200	6,860	2.696
Distributed Generation- Peak	Not Specified	10,257	7,649	3.006
Fuel Cells	Not Specified	7,930	5,913	2.324
Gas Turbine	Liquefied Gas Propane	13,503	10,069	3.957
	Natural Gas	13,918	10,379	4.079
	Refinery Gas	15,000	11,186	4.396
Geothermal	Not Specified	35,376	26,380	10.368
Integrated Coal Gasification Combined Cycle	Not Specified	8,765	6,536	2.569
Integrated Coal Gasification Combined Cycle with Carbon Sequestration	Not Specified	10,781	8,039	3.16
Internal Combustion Engine	Gasoline	9,387 (converted)	7,000 (original units)	2.751
	Natural Gas	10,538	7,858	3.088
	No. 2 Fuel Oil	10,847	8,089	3.179
	Refinery Gas	14,000	10,440	4.103
Scrubbed Coal – New	Not Specified	9,200	6,860	2.696
Steam Turbine (Boiler)	Coal (Anthracite)	11,792	8,793	3.456
	Coal (Bituminous)	9,941	7,413	2.913
	Coal (Lignite)	10,933	8,153	3.204
	Coal (Sub-Bituminous)	10,354	7,721	3.034
	Liquefied Propane Gas	14,200	10,589	4.162
	Natural Gas	10,502	7,831	3.078
	No. 2 Fuel Oil	8,653	6,453	2.536
	Refuse, Bagasses, non wood	13,706	10,221	4.017
	Wood and Wood Waste	15,725	11,726	4.609

Source: API 2009. "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry," Prepared for American Petroleum Institute (API), Prepared by URS Corp., August 2009, Table 4-2.

## O&GP ST-03

### CALCULATING EMISSIONS FROM UNMETERED DRILL RIG, WORKOVER RIG, AND OTHER STATIONARY ENGINES USING A LOAD FACTOR

A single drill rig may include three to seven (or more) engines, including draw works, mud pumps, and generator engines. Workover rigs used to perform major maintenance on wells, including removing and replacing the tubing string, and well re-completions, typically have fewer and smaller engines than drill rigs. Stationary engines are also used to drive electricity generators and in other applications.

You should use the methodologies provided in Chapter 12 of the GRP to calculate emissions from all drill rigs, workover rigs, and other stationary engines for which fuel consumption data are available.

**Equation 12c: Calculating Emissions from Drill Rig, Workover Rig, and Other Stationary Engines, Using a Load Factor<sup>13</sup>**

$$E = HP_i \times LF_i \times HR_i \times EF \times t_{i,annual}$$

where:

$$HR_i = BSFC_i \times HHV$$

and:

$E$  = the emissions of CO<sub>2</sub>, CH<sub>4</sub>, or N<sub>2</sub>O for engine  $i$  (t/yr)

$HP_i$  = the horsepower of engine  $i$  (hp)

$LF_i$  = the load factor of engine  $i$

$HR_i$  = Heat Rate of engine  $i$  (Btu/hp-hr) (Note: if the data on  $BSFC_i$  or  $HHV$  needed to calculate an equipment-specific heat rate is not available, please refer to Table 12-2 for default heat rates)

$BSFC_i$  = the brake specific fuel consumption of engine  $i$  (lb-fuel/hp-hr)

$HHV$  = the higher heating value of the diesel fuel (Btu/lb)

$EF$  = the emissions factor of CO<sub>2</sub>, CH<sub>4</sub>, or N<sub>2</sub>O from Chapter 12 of the GRP on an energy basis (t/Btu)

$T_{i,annual}$  = the actual hours of operation of engine  $i$  (hr/yr)

O&GP ST-04:

**CALCULATING EMISSIONS FROM UNMETERED HEATERS AND BOILERS USING A LOAD FACTOR**

Heaters and boilers used in the O&GP sector may include external combustion devices at gas processing plants, large compressor stations and gas and oil wellheads. Examples of such devices include steam boilers, heaters used in a variety of gas processing steps, reboilers used in dehydration and acid gas removal, and separator and tank heaters.

<sup>13</sup> USEPA, 2005. *User's Guide for the Final NONROAD Model*, U.S. Environmental Protection Agency, EPA420-R-05-013.

You should use the methodologies provided in Chapter 12 of the GRP to calculate emissions from all heaters and boilers for which fuel consumption data are available.

**Equation 12d: Calculating Emissions from Heaters and Boilers Using a Load Factor**

$$E = [(Q_{firing}/HHV) \times EF \times t_{annual}]/2204.62$$

where:

$E$  = the annual emissions of CO<sub>2</sub>, CH<sub>4</sub>, or N<sub>2</sub>O for a heater/boiler (t/yr)

$Q_{firing}$  = the nameplate firing capacity of the heater/boiler (MMBtu/hr)

$HHV$  = the higher heating value of the fuel (MMBtu/scf)

$EF$  = the emissions factor of CO<sub>2</sub>, CH<sub>4</sub>, or N<sub>2</sub>O from Chapter 12 of the GRP (lb/scf) Note that the emissions factor of CO<sub>2</sub> can be computed using the carbon content of the fuel as follows:  $EF = (\text{mass fraction of carbon in the fuel}) \times (44 \text{ g CO}_2/12 \text{ g C})$

$t_{annual}$  = the actual annual hours of usage of the heater/boiler (hr/yr)

**12.4.1: Example: Calculating Emissions for an Unmetered Stationary Combustion Device Using a Load Factor**

ACME Oil has a small, 150 horsepower, two-stroke natural gas-fired reciprocating engine that it uses to drive an un-permitted compressor at a remote location in the U.S. The engine lacks a fuel use meter, but it has a time of use meter indicating that it was in operation 50 percent of the time during the reporting year.

The first step in calculating the emissions for the engine is to select an appropriate quantification methodology based on the type of device and the available data. Since fuel consumption data are not available, the calculation methodologies contained in the GRP are not applicable. However, because the hours of operation of the device are metered, one of the alternative methodologies presented in this section may be used instead. O&GP ST-01 applies to engines and turbines used to drive compressors, and therefore can be applied to the compressor engine.

First, using emissions factor data from the GRP (see Tables 12.1, 12.7, and 12.9), the following emissions factors are computed for each GHG:

$$EF_{CO_2} = (53.06 \text{ kg CO}_2/\text{MMBtu})(1 \text{ t}/1000 \text{ kgs}) = 0.05306 \text{ t CO}_2/\text{MMBtu}.$$

$$EF_{CH_4} = (658 \text{ g CH}_4/\text{MMBtu})(1 \text{ t}/1,000,000 \text{ g}) = 0.000658 \text{ t CH}_4/\text{MMBtu}.$$

$$EF_{N_2O} = (0.1 \text{ g } CH_4/MMBtu)(1 \text{ t}/1,000,000 \text{ g}) = 0.0000001 \text{ t } CH_4/MMBtu.$$

Equation 12a also requires a load factor (LF), but as data on the engine's load factor is unavailable from the engine manufacturer, ACME Oil must use the default load factor of 0.75. Finally, ACME Oil knows (from the engine's time meter) that the engine was in use 4380 hours during the year (i.e., 50 percent of the time).

With the above-determined default values for the emission and load factors and the hours of operation of the engine, ACME Oil can now solve Equation 12a. First, ACME Oil calculates CO<sub>2</sub> emissions from the engine as follows:

$$E_{CO_2} = (150 \text{ hp}) \times 0.75 \times (0.007858 \text{ MMBtu}/hp\text{-hr}) \times 0.05306 \text{ t } CO_2/MMBtu \times 4380 \text{ hrs} = 205.455 \text{ t } CO_2$$

ACME Oil calculates the engine's CH<sub>4</sub> emissions as follows:

$$E_{CH_4} = (150 \text{ hp}) \times 0.75 \times (0.007858 \text{ MMBtu}/hp\text{-hr}) \times 0.000658 \text{ t } CH_4/MMBtu \times 4380 \text{ hrs} = 2.55 \text{ t } CH_4$$

ACME Oil calculates the engine's N<sub>2</sub>O emissions as follows:

$$E_{N_2O} = (150 \text{ hp}) \times 0.75 \times (0.007858 \text{ MMBtu}/hp\text{-hr}) \times 0.0000001 \text{ t } N_2O/MMBtu \times 4380 \text{ hrs} = 0.000387 \text{ t } N_2O$$

Finally, ACME Oil can compute the total emissions of the engine on a CO<sub>2</sub>-e basis by multiplying the GWPs for CO<sub>2</sub>, CH<sub>4</sub> and N<sub>2</sub>O (1, 21 and 310, respectively from Appendix B of the GRP) by the volume of emissions of each gas and then summing the total CO<sub>2</sub>-e as follows:

$$\text{Total emissions of engine} = (205.455 \text{ t } CO_2 \times 1) + (2.55 \text{ t } CH_4 \times 21) + (0.000387 \text{ t } N_2O \times 310) = 259.125 \text{ t } CO_2\text{-e}$$

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O&GP ST-05:

## ALBERTA ENVIRONMENT MANDATORY REPORTING FOR COMBUSTION OF PETROLEUM COKE IN A FLUIDIZED BED COKER

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Most oil sand and heavy oil upgrading stationary combustion activities, such as coking and hydroprocessing activities, can be quantified using the methods described in Chapter 12 of the GRP. The primary exception is the combustion of petroleum coke in a fluidized bed coker, which utilizes a site specific mass balance approach because the continuous process employed in this device and the quantities of coke produced do not allow for direct measurement.

The Registry accepts all GHG emission calculation methodologies mandated Alberta Environment's regulatory GHG reporting program.

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## 12.5 Flaring Emissions

Flaring is used to consume waste gases in a safe and reliable manner through combustion in an open flame. In the petroleum industry, flaring occurs during well testing and production operations. The primary purpose of flaring is to act as a safety device to protect vessels or pipes from over-pressuring due to unplanned upsets. Flares are routinely used to dispose of flammable gases that are either unusable or uneconomical to recover. Flaring can also be used to depressurize gas-processing equipment during routine maintenance.

There are different types of flares, from small open-ended pipes used on wells during activities such as workovers and well completions, to large horizontal or vertical flares with pilots used at refineries. Flares are used temporarily or permanently depending on the type of operation.

CO<sub>2</sub> and N<sub>2</sub>O emissions are products of the combustion process. In cases when the combustion is incomplete, or when there are operational problems, CH<sub>4</sub> emissions can also be produced. The combustion efficiency is variable, and is primarily dependent on the flame stability which in turn depends on the gas velocity, heat content, and wind conditions.

Gas volumes can be difficult to quantify because flares are used to combust gas that is released as a result of a variety of unplanned and unmetered activities. Determining volumes of GHGs during well completion and/or workover activities can be particularly challenging.

The Registry recommends that you keep comprehensive logs and documentation of flaring activities and perform gas analysis (GC/MS) when possible. You should use the methods presented below to quantify emissions from flaring. These methods require the estimation of the flare gas flow rate and composition.

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### O&GP ST-06:

#### FLARE EMISSIONS ESTIMATION METHODOLOGY<sup>14</sup>

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In cases where flared volume and gas composition data are available, you can estimate flared gas volumes based on the vented volume estimates for the source categories that were flared. You can calculate CO<sub>2</sub> and CH<sub>4</sub> emissions using the volume of gas flared and the flare gas carbon fraction using Equation 12e Equation 12f and Equation 12g below using either a known or default combustion efficiency.

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<sup>14</sup> API 2009. "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry," Prepared for American Petroleum Institute (API), Prepared by URS Corp., August 2009. Section 4.6, Equations 4-14, 4-15 and 4-16.

**Equation 12e: Calculating CO<sub>2</sub> Emissions from Flares**

$$E_{CO_2} = [HC \times CF_{HC} \times (FE/1-FE) \times (44/12)] + M_{CO_2}$$

where;

$E_{CO_2}$  = emissions of CO<sub>2</sub> from flaring (t/yr)

$HC$  = flare hydrocarbon emission rate from the flare (t)

$CF_{HC}$  = carbon weight fraction in hydrocarbon

$FE$  = flare combustion efficiency

$44/12$  = C to CO<sub>2</sub> conversion factor

$M_{CO_2}$  = mass of CO<sub>2</sub> in flared stream based on CO<sub>2</sub> composition of stream (t)

When vendor information about combustion efficiency is not available, you should use a default combustion efficiency value of 98 percent (EPA, AP-42 Section 13.5.2, September 1991), and follow Equation 12f and 12g.

**Equation 12f: Calculating CO<sub>2</sub> Emissions from Flares using Default Combustion Efficiency Factor**

$$E_{CO_2} = V_f \times M_{CO_2} \times MW_{CO_2} \times (1/2204.62) \times \{ \sum [(mole_{hydrocarbon}/mole_{gas}) \times (A \text{ mole C}/mole_{hydrocarbon}) \times (0.98 \text{ mole CO}_2 \text{ formed}/mole \text{ C combusted})] + B \text{ mole CO}_2/mole \text{ gas} \}$$

where;

$E_{CO_2}$  = emissions of CO<sub>2</sub> from flaring, in tonne/yr

$V_f$  = flare inlet gas volume, in scf/yr

$M_{CO_2}$  = CO<sub>2</sub> molar conversion factor

Molar volume conversion = conversion from molar volume to mass (379.3 scf/lbmole or 23.685 m<sup>3</sup>/kgmole)

$MW_{CO_2}$  = molecular weight of CO<sub>2</sub>

Mass conversion = tonnes/2204.62lb or tonne/1000 kg

2204.62 = conversion factor from lb to t

0.98 = default combustion efficiency

$A$  = number of moles of carbon (C) for the flared hydrocarbon

$B$  = moles of CO<sub>2</sub> present in the flared gas stream

**Equation 12g: Calculating CH<sub>4</sub> Emissions from Flares**

$$E_{CH_4} = Q_{fuel} \times M_{CH_4} \times R_{CH_4} \times (lbmole/379.3 \text{ scf}) \times MW_{CH_4} \times (1/2204.62)$$

where;

$E_{CH_4}$  = emissions of CH<sub>4</sub> from flaring (t/yr)

$Q_{fuel}$  = flare inlet gas volume (scf/yr)

$M_{CH_4}$  = molar fraction of CH<sub>4</sub>

$R_{CH_4}$  = percent residual of CH<sub>4</sub> (assumed to be 2%)

$lbmole/379.3$  = molar volume conversion from scf to lb-mole

$MW_{CH_4}$  = molecular weight of CH<sub>4</sub>

$2204.62$  = conversion factor from lb to t

There is little information available for determining N<sub>2</sub>O emissions from flaring operations. You may use the simplified estimation method approach below to quantify N<sub>2</sub>O emissions.

O&GP ST-07:

**SIMPLIFIED ESTIMATION METHOD: EMISSIONS FROM FLARES**

When flared gas composition is unknown, you can use Equation 12h to estimate CO<sub>2</sub>, CH<sub>4</sub> and/or N<sub>2</sub>O emissions. If you estimate emissions using Equation 12h, the resulting emissions will count toward your organization's five percent threshold for simplified estimation methods (described in Chapter 11 of the GRP). Therefore, emissions calculated using this method, combined with emissions calculated using other simplified estimation methods cannot exceed five percent of your entity's total emissions. Table 12.3 presents the list of simplified GHG emission factors for gas flares.

**Equation 12h: Calculating Flared Emissions Using Simplified Emissions Factors**

$$E_i = V \times EF_i$$

where;

$E_i$  = emissions of CO<sub>2</sub>, CH<sub>4</sub> or N<sub>2</sub>O from flaring (t/yr)

$V$  = Volume produced (m<sup>3</sup>, scf, or bbl)

$EF$  = emissions factor of GHG per unit production (see Table 12.3)

**Table 12.3 – GHG Emissions for Gas Flares<sup>15</sup>**

Flare Source	Emission Factors			Units
	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O	
<b>Original Units</b>				
Flaring - gas production	1.2E-03	7.6E-07	2.1E-08	Gg/10 <sup>6</sup> m <sup>3</sup> gas production
Flaring - sweet gas processing	1.8E-03	1.2E-06	2.5E-08	Gg/10 <sup>6</sup> m <sup>3</sup> gas receipts
Flaring - sour gas processing	3.6E-03	2.4E-06	5.4E-08	Gg/10 <sup>6</sup> m <sup>3</sup> gas receipts
Flaring - conventional oil production	4.1E-02	2.5E-05	6.4E-07	Gg/1000 m <sup>3</sup> conventional oil Production
Flaring - heavy oil/cold bitumen production	2.2E-02	1.4E-04	4.6E-07	Gg/1000 m <sup>3</sup> heavy oil production
Flaring - thermal oil production	2.7E-02	1.6E-05	2.4E-07	Gg/1000 m <sup>3</sup> crude bitumen Production
<b>Units Converted to tonnes/10<sup>6</sup> scf or tonnes/1000 bbl</b>				
Flaring - gas production	3.4E-02	2.2E-05	5.9E-07	tonnes/10 <sup>6</sup> scf gas production
Flaring - sweet gas processing	5.1E-02	3.4E-05	7.1E-07	tonnes/10 <sup>6</sup> scf gas receipts
Flaring - sour gas processing	0.10	6.8E-05	1.5E-06	tonnes/10 <sup>6</sup> scf gas receipts
Flaring - conventional oil production	6.5	4.0E-03	1.0E-04	tonnes/1000 bbl conventional oil production
Flaring - heavy oil production/cold bitumen production	3.5	2.2E-02	7.3E-05	tonnes/1000 bbl heavy oil production
Flaring - thermal oil production	4.3	2.5E-03	3.8E-05	tonnes/1000 bbl crude bitumen production
<b>Units Converted to tonnes/10<sup>6</sup> m<sup>3</sup> or tonnes/1000 m<sup>3</sup></b>				
Flaring - gas production	1.2	7.6E-04	2.1E-05	tonnes/10 <sup>6</sup> m <sup>3</sup> gas production
Flaring - sweet gas processing	1.8	1.2E-03	2.5E-05	tonnes/10 <sup>6</sup> m <sup>3</sup> gas receipts
Flaring - sour gas processing	3.6	2.4E-03	5.4E-05	tonnes/10 <sup>6</sup> m <sup>3</sup> gas receipts
Flaring - conventional oil production	41.0	2.5E-02	6.4E-04	tonnes/1000 m <sup>3</sup> conventional oil production
Flaring - heavy oil/cold bitumen production	22.0	1.4E-01	4.6E-04	tonnes/1000 m <sup>3</sup> heavy oil production
Flaring - thermal oil production	27.0	1.6E-02	2.4E-04	tonnes/1000 m <sup>3</sup> crude bitumen production
Source: IPCC, 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2, Chapter 4 (Fugitive Emissions) Table 4.2.4, 2006.				

**12.5.1: Example: Calculation of Combustion Emissions from a Gas Flare<sup>16</sup>**

An Oil and Gas Production Installation produces three million scf of natural gas per day. In a given year, 20 million scf of field gas is flared at the installation. The flare gas composition is: 80 percent CH<sub>4</sub>, 15 percent C<sub>2</sub>H<sub>6</sub>, and five percent C<sub>3</sub>H<sub>8</sub>

<sup>15</sup> API 2009. "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry," Prepared for American Petroleum Institute (API), Prepared by URS Corp., August 2009.

<sup>16</sup> Ibid.

Since vendor data on the combustion efficiency of the flare is not available, the company that operated the installation should estimate CO<sub>2</sub> emissions by assuming 98 percent combustion efficiency and two percent uncombusted CH<sub>4</sub>.

The company calculates CO<sub>2</sub> emissions from this installation using Equation 12f as follows.

$$E(\text{CO}_2) = (20 \times 10^6 \text{ scf gas/yr}) \times (\text{lbmole gas}/379.3 \text{ scf gas}) \times \{[(0.80 \text{ lbmole CH}_4/\text{lbmole gas} \times \text{lbmole C}/\text{lbmole CH}_4) + (0.15 \text{ lbmole C}_2\text{H}_6/\text{lbmole gas} \times 2 \text{ lbmole C}/\text{lbmole C}_2\text{H}_6) + (0.05 \text{ lbmole C}_3\text{H}_8/\text{lbmole gas} \times 3 \text{ lbmole C}/\text{lbmole C}_3\text{H}_8)] \times (0.98 \text{ lbmole CO}_2/\text{lbmole C}_{\text{combusted}}) + 0.12 \text{ lbmole CO}_2/\text{lbmole gas}\} \times (44 \text{ lb CO}_2/\text{lbmole CO}_2) \times (\text{tonne}/2204.62 \text{ lb})$$

$$E(\text{CO}_2) = 1,415 \text{ tonnes CO}_2/\text{yr}$$

The company uses Equation 12g to estimate CH<sub>4</sub> emissions from the installation.

$$E(\text{CH}_4) = (20 \times 10^6 \text{ scf gas/yr}) \times (0.80 \text{ scf CH}_4/\text{scf gas}) \times (0.02 \text{ scf CH}_4/\text{scf CH}_4 \text{ total}) \times (\text{lbmole CH}_4/379.3 \text{ scf CH}_4) \times (16 \text{ lb CH}_4/\text{lbmole CH}_4) \times (\text{tonne}/2204.62 \text{ lb})$$

$$E(\text{CH}_4) = 6.1 \text{ tonnes CH}_4/\text{yr}$$

The company calculates N<sub>2</sub>O emissions from the installation by using Equation 12h and the emission factors from Table 12.3 as shown below:

$$E(\text{N}_2\text{O}) = (3 \times 10^6 \text{ scf gas/day}) \times (365 \text{ days/yr}) \times (5.9 \times 10^{-7} \text{ tonnes N}_2\text{O}/10^6 \text{ scf gas})$$

$$E(\text{N}_2\text{O}) = 6.46 \times 10^{-4} \text{ tonnes N}_2\text{O}/\text{yr}$$

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#### O&GP ST-08:

### ALBERTA ENVIRONMENT MANDATORY REPORTING FOR FLARING IN OIL SANDS AND HEAVY OIL UPGRADING

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Alberta Environment (AENV) requires oil sands operators to report all flaring events and the associated release of sulfur dioxide. The timing of the report is based on the severity of the event. Operators file monthly and annual air reports with AENV, which summarize flaring events by source and provide quantification of the amount of sulfur dioxide emitted. The ERCB also requires monthly and annual reporting of flaring events.

Oil sands operators utilize the same information base (flow quantification and stream composition) to determine GHG emissions associated with flaring. A combustion efficiency of 99.5 percent is assumed for flares, which is consistent with engineered flares used in refineries.

The Registry accepts all GHG emission calculation methodologies mandated by Alberta Environment's regulatory GHG reporting program.

## **Chapter 13: Direct Emissions from Mobile Combustion**

REFER TO GRP.

## Chapter 14: Indirect Emissions from Electricity Use

REFER TO GRP

## **Chapter 15 Indirect Emissions from Imported Steam, District Heating, Cooling and Electricity from a CHP Plant**

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### 15.1 Calculating Indirect Emissions from Heat and Power Produced at a CHP Plant

REFER TO GRP.

Please note that the method in the GRP also applies to CHP facilities operated by one entity and transferred to another for steam flood and cyclic steam wells.

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### 15.2 Calculating Indirect Emissions from Imported Steam or District Heating from a Conventional Boiler Plant

REFER TO GRP.

Please note that the method in the GRP also applies to steam generators operated by one entity and transferred to another for steam flood and cyclic steam wells.

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### 15.3 Calculating Indirect Emissions from District Cooling

REFER TO GRP.

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### 15.4 Example: Indirect Emissions from District Heating

REFER TO GRP.

## Chapter 16 Direct Fugitive Emissions

This section contains quantification methodologies for fugitive emissions that are unique to the O&GP sector. Table 16.1 lists the Registry-approved calculation methods for quantifying fugitive emission along with each method's data requirements.

**Table 16.1 Summary of Calculation Methods for Reporting Fugitive Emissions**

Method	Data Requirements
O&GP FG-01	Mass emission rate of gas, Annual usage of component, Emissions factor for CO <sub>2</sub> , and CH <sub>4</sub> , Oil and Gas Production Installation production data, Molecular weight of CH <sub>4</sub> and CO <sub>2</sub>
O&GP FG-02	Emissions factor for CO <sub>2</sub> , and CH <sub>4</sub> , Molecular weight of CH <sub>4</sub> and CO <sub>2</sub> , Annual usage of component
O&GP FG-03	Mass emission rate of gas, Annual usage of equipment type, Emissions factor for CO <sub>2</sub> , and CH <sub>4</sub> , Oil and Gas Production Installation production data, Molecular weight of CH <sub>4</sub> and CO <sub>2</sub>
O&GP FG-04	Emissions factor for CO <sub>2</sub> , and CH <sub>4</sub> , Molecular weight of CH <sub>4</sub> and CO <sub>2</sub> , Annual usage per facility type
O&GP FG-05	Mass fraction of CO <sub>2</sub> , and CH <sub>4</sub> in the water, Mass of non-re-injected water
O&GP FG-06	Emission factor for CH <sub>4</sub> and CO <sub>2</sub> , CH <sub>4</sub> and CO <sub>2</sub> content, Number of stations or components

### 16.1 Wellhead and Oil and Gas Production Installation or Facility Losses

This section contains methods for calculating fugitive emissions from equipment in oil and gas exploration and production facilities. Fugitive emissions result from leaks in equipment and components that carry pressurized gases, including, but not limited to wellheads, gathering pipelines, valves, flanges, seals, fittings, and open ended lines. CH<sub>4</sub> from natural gas is the primary GHG associated with fugitive emissions in O&GP activities, but CO<sub>2</sub> emissions can also be significant at sites where the natural gas has naturally occurring CO<sub>2</sub> content. When considering fugitive emissions from O&GP activities, you must distinguish between primary oil and gas production, as the distribution of components will vary between the two. Oil production tends to utilize more heavy liquid components, while gas production typically utilizes more gas/vapor and light liquid components.

It is worth noting that some larger central compressor stations and gas processing plants are required to estimate their fugitive emissions as a part of the permitting process for the facility. While these permits do not require estimates of CH<sub>4</sub> emissions, the permits can provide information that is useful for estimating GHG emissions.

This section contains guidance for calculating both fugitive emissions that can be identified under a permitting process, and those fugitive emissions that occur at smaller facilities whose

components are not subjected to a permitting process. Thus, you must report fugitive emissions for both “permitted” and “un-permitted” sources.

Fugitive emissions are typically quantified by applying an emission rate to site-specific equipment and activities while taking gas composition into account. The availability of these data will vary from facility to facility. The methods in this section provide options for quantifying fugitive emissions from oil and gas production installations on a component level, equipment level and facility-wide level.

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## O&GP FG-01:

### COMPONENT LEVEL ESTIMATE OF FUGITIVE EMISSIONS FROM OIL AND GAS PRODUCTION INSTALLATIONS

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This method relies on estimates of the mass emissions rate of gas from each component in an Oil and Gas Production Installation, gas composition information, and component usage data to quantify fugitive emissions. Component-level information is then summed to determine total installation emissions. The mass emission rate can be directly measured, correlated, or based on default values, as described in Step 3, below.

This approach involves five steps:

1. Identify the number and types of components employed throughout the installation;
2. Determine the composition of the natural gas stream;
3. Determine the appropriate mass emission rate of gas for each component;
4. Calculate CH<sub>4</sub> and CO<sub>2</sub> emissions for each component; and
5. Convert CH<sub>4</sub> emissions to units of CO<sub>2</sub>-e and sum to determine total emissions.

#### STEP 1: IDENTIFY THE NUMBER AND TYPES OF COMPONENTS EMPLOYED THROUGHOUT THE FACILITY.

---

Use a count that represents the actual inventory of all of the individual components that are in operation at an installation. This will include pumps, valves, pressure relief valves, flanges, agitators, and compressors, seals, sampling connections and open-ended lines.

#### STEP 2: DETERMINE THE COMPOSITION OF THE NATURAL GAS STREAM

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Determine the mass fractions of CH<sub>4</sub>, CO<sub>2</sub>, and total organic compound species (TOCs) for the natural gas stream that is passing through the components. Gas composition analysis methods are included in the following resources:

- ASTM D 2650: Standard Test Method for Chemical Composition of Gases by Mass Spectrometry
- ASTM D1945-03: Standard Test Method for Analysis of Natural Gas by Gas Chromatography

- ASTM D4984–06: Standard Test Method for Carbon Dioxide in Natural Gas Using Length-of-Stain Detector Tubes

### STEP 3: DETERMINE THE APPROPRIATE MASS EMISSION RATE OF GAS FOR EACH COMPONENT

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The selection of methods for estimating mass emission rates for components is determined by data availability. Depending on the information that is available, you can select from three options - directly measured rates or source screened rates.

#### Directly Measured Rates:

“Bagging” is a sampling method that involves enclosing individual components in an impermeable bag, and measuring the vapors that are leaked into it. Bagged sample measurements can be used to determine component fugitive mass emissions rates. Additional information on bag sampling methods and techniques can be found in Appendix C of U.S. EPA’s “Preferred and Alternative Methods for Estimating Fugitive Emissions from Equipment Leaks.”<sup>17</sup>

High volume samplers can also be used to establish fugitive mass emissions rates for leaking components. High volume samplers pull a large volume of air and leaked gas into a hydrocarbon detector unit, which measures the concentration of hydrocarbons in both the ambient air and in the sampled air. You can then calculate a mass hydrocarbon emission rate by multiplying the flow rate of the measured sample by the difference in the hydrocarbon concentration in the sampled and ambient air.

#### Source Screened Rates:

You can calculate source screened rates by measuring the concentration of leaking organic compounds from a component’s leak interface using a portable organic compound analyzer (screening device). This concentration level is then converted into a mass emission rate by use of an equipment-specific correlation equation. The following U.S. EPA documents provide guidance on performing screen measurements and correlating them into mass emission rates:

- Preferred and Alternative Methods for Estimating Fugitive Emissions from Equipment Leaks,<sup>18</sup> and;
- 1995 Protocol for Equipment Leak Emission Estimates.<sup>19</sup>

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<sup>17</sup> U.S. EPA. “Preferred and Alternative Methods for Estimating Fugitive Emissions from Equipment Leaks.” 1996. <http://www.epa.gov/ttn/chief/eiip/techreport/volume02/ii04.pdf> Accessed 6/9/09.

<sup>18</sup> Ibid.

<sup>19</sup> U.S. EPA. “Protocol for Equipment Leak Emission Estimates,” 1995. <http://www.epa.gov/ttnchie1/efdocs/equiplks.pdf> Accessed 4/26/10.

## STEP 4: CALCULATE CH<sub>4</sub> AND CO<sub>2</sub> EMISSIONS FOR EACH COMPONENT.

---

Using the values obtained in steps 1-3, above, calculate total CH<sub>4</sub> and CO<sub>2</sub> emissions from all components using Equation 16a below.

### Equation 16a: Calculating CO<sub>2</sub> and CH<sub>4</sub> Emissions from Exploration and Production Facilities Based on Component Level Emission Factors

$$E_{CH_4/CO_2} = \sum_i \sum_j \sigma_{fugitivei.j} \times (f_{CH_4/CO_2} / f_{TOC}) \times t_{annual}$$

where,

$E_{CH_4/CO_2}$  = the total fugitive emissions of CH<sub>4</sub> or CO<sub>2</sub> from each facility (tonne/yr)

$\sigma_{fugitivei.j}$  = the measured fugitive mass emissions rate of gas from component  $i$  in service type  $j$  (tonne-TOC/hr)

$f_{CH_4/CO_2}$  = the mass fraction of CH<sub>4</sub>/CO<sub>2</sub> in the gas stream

$f_{TOC}$  = the mass fraction of total organic carbon species in the gas stream

$t_{annual}$  = the annual usage of the component (hr/yr)

## STEP 5: CONVERT CH<sub>4</sub> EMISSIONS TO UNITS OF CO<sub>2</sub> EQUIVALENT.

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To convert CH<sub>4</sub> emissions to tonnes of CO<sub>2</sub>-e, multiply the quantity of CH<sub>4</sub> calculated in Step 4 by its GWP (21). Sum all values to determine the total emissions from components in tonnes CO<sub>2</sub>-e.

### O&GP FG-02:

#### COMPONENT LEVEL ESTIMATE OF FUGITIVE EMISSIONS FROM E&P FACILITIES USING EMISSION FACTORS

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In the absence of the measured approaches described above (O&GP FG-01), you can use Equation 16b and the default mass emission rates provided in Table 16.2 to determine component-level emissions for U.S. operations. Operations in Canada should use Equation 16b and the component-level emission factors in Table 16.3 to estimate fugitive emissions.

**Equation 16b: Calculating CO<sub>2</sub> and CH<sub>4</sub> Emissions from Exploration and Production Facilities Based on Component Level Emission Factors**

$$E_{CH_4/CO_2} = \sum_i \sum_j \sigma_{fugitivei,j} \times (f_{CH_4/CO_2} / f_{TOC/THC}) \times t_{annual}$$

where,

$E_{CH_4/CO_2}$  = the total fugitive emissions of CH<sub>4</sub> or CO<sub>2</sub> from each facility (tonne/yr)

$\sigma_{fugitivei,j}$  = the estimated fugitive mass emissions rate of gas from component *i* in service type *j* (tonne-TOC/hr) for U.S. operations or (tonne-THC/hr) for Canadian operations

$f_{CH_4/CO_2}$  = the mass fraction of CH<sub>4</sub>/CO<sub>2</sub> in the gas stream

$f_{TOC/THC}$  = the mass fraction of total organic carbon species in the gas stream for U.S. operations or total hydrocarbons for Canadian operations

$t_{annual}$  = the annual usage of the component (hr/yr)

**Table 16.2 – U.S. Component Level TOC Emission Rates by O&GP Facility Type<sup>20</sup>**

Component Type	Emission Factor (tonne TOC/component-hr)
<b>Offshore Facilities</b>	
Valves	5.14E-07
Pump seals	1.95E-07
Others	6.94E-06
Connectors	1.08E-07
Flanges	1.97E-07
Open-ended lines	1.01E-06
<b>Oil and Gas Production Facilities</b>	
Valves – gas production	2.63E-06
Valves – heavy crude production	1.30E-08
Valves – light crude production	1.32E-06
Connectors – gas production	3.21E-07
Connectors – heavy crude production	7.98E-09
Connectors – light crude production	1.64E-07
Flanges – gas production	1.18E-07
Flanges – heavy crude production	2.19E-08
Flanges – light crude production	7.69E-08
Open-ended lines – gas production	6.86E-07

<sup>20</sup> API 2009. "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry," Prepared for American Petroleum Institute (API), Prepared by URS Corp., August 2009. Table 6-2.

Component Type	Emission Factor (tonne TOC/component-hr)
Open-ended lines – heavy crude production	1.55E-07
Open-ended lines – light crude production	1.21E-06
Pump Seals – gas production	1.95E-07
Pump Seals – light crude production	3.18E-07
Others – gas production	9.19E-06
Others – heavy crude production	6.99E-08
Others – light crude production	7.50E-06
<b>Gas Plants</b>	
Valves	3.86E-06
Pump seals	1.15E-05
Others	4.86E-06
Connectors	2.74E-07
Flanges	4.38E-07
Open-ended lines	1.03E-06

**Table 16.3 – Canadian Component Level Emission Factors for Estimating THC Emissions from Equipment Leaks<sup>21</sup>**

Factor Group	Type	Service	Equipment Component	Emissions Factor (kg/hr) <sup>a</sup>
GAS	ALL	Fuel Gas	Connectors	8.18E-04
GAS	ALL	Fuel Gas	Chemical Injection Pumps	1.62E-01
GAS	ALL	Fuel Gas	Controllers	2.38E-01
GAS	ALL	Fuel Gas	Compressor Seals	7.13E-01
GAS	ALL	Fuel Gas	Control Valves	1.62E-02
GAS	ALL	Fuel Gas	Open-Ended Lines	4.67E-01
GAS	ALL	Fuel Gas	Pressure Relief Valves	1.70E-02
GAS	ALL	Fuel Gas	Pressure Regulators	8.11E-03
GAS	ALL	Fuel Gas	Compressor Starts	6.34E-03
GAS	ALL	Fuel Gas	Valves	2.81E-03
GAS	ALL	Gas/Vapor	Connectors	7.06E-04
GAS	ALL	Gas/Vapor	Chemical Injection Pumps	1.62E-01
GAS	ALL	Gas/Vapor	Controllers	2.38E-01
GAS	ALL	Gas/Vapor	Compressor Seals	7.13E-01
GAS	ALL	Gas/Vapor	Control Valves	1.46E-02
GAS	ALL	Gas/Vapor	Open-Ended Lines	4.27E-01
GAS	ALL	Gas/Vapor	Pressure Relief Valves	1.70E-02
GAS	ALL	Gas/Vapor	Pressure Regulators	8.11E-03
GAS	ALL	Gas/Vapor	Valves	2.46E-03
GAS	ALL	Light Liquid	Connectors	5.51E-04
GAS	ALL	Light Liquid	Control Valves	1.77E-02

<sup>21</sup> CAPP/Clearstone National Inventory of GHG Emissions by the Upstream Oil and Gas Industry Report. September 2004. Volume 5. Table 3.1 - 3.2

GAS	ALL	Light Liquid	Open-Ended Lines	1.83E-02
GAS	ALL	Light Liquid	Pressure Relief Valves	5.39E-03
GAS	ALL	Light Liquid	Pump Seals	2.32E-02
GAS	ALL	Light Liquid	Valves	3.62E-03
GAS	SOUR	Gas/Vapor	Connectors	1.36E-04
GAS	SOUR	Gas/Vapor	Control Valves	9.64E-03
GAS	SOUR	Gas/Vapor	Open-Ended Lines	1.89E-01
GAS	SOUR	Gas/Vapor	Pressure Regulators	4.72E-05
GAS	SOUR	Gas/Vapor	Valves	1.16E-03
GAS	SWEET	Gas/Vapor	Connectors	8.18E-04
GAS	SWEET	Gas/Vapor	Control Valves	1.62E-02
GAS	SWEET	Gas/Vapor	Open-Ended Lines	4.67E-01
GAS	SWEET	Gas/Vapor	Pressure Regulators	8.39E-03
GAS	SWEET	Gas/Vapor	Valves	2.81E-03
OIL	ALL	Fuel Gas	Connectors	2.46E-03
OIL	ALL	Fuel Gas	Chemical Injection Pumps	1.62E-01
OIL	ALL	Fuel Gas	Controllers	2.38E-01
OIL	ALL	Fuel Gas	Compressor Seals	8.05E-01
OIL	ALL	Fuel Gas	Control Valves	1.46E-02
OIL	ALL	Fuel Gas	Open-Ended Lines	3.08E-01
OIL	ALL	Fuel Gas	Pressure Relief Valves	1.63E-02
OIL	ALL	Fuel Gas	Pressure Regulators	6.68E-03
OIL	ALL	Fuel Gas	Compressor Starts	6.34E-03
OIL	ALL	Fuel Gas	Valves	1.51E-03
OIL	ALL	Gas/Vapor	Connectors	2.46E-03
OIL	ALL	Gas/Vapor	Chemical Injection Pumps	1.62E-01
OIL	ALL	Gas/Vapor	Controllers	2.38E-01
OIL	ALL	Gas/Vapor	Compressor Seals	8.05E-01
OIL	ALL	Gas/Vapor	Control Valves	1.46E-02
OIL	ALL	Gas/Vapor	Open-Ended Lines	3.08E-01
OIL	ALL	Gas/Vapor	Pressure Relief Valves	1.63E-02
OIL	ALL	Gas/Vapor	Pressure Regulators	6.68E-03
OIL	ALL	Gas/Vapor	Valves	1.51E-03
OIL	ALL	Heavy Liquid	Connectors	7.50E-06
OIL	ALL	Heavy Liquid	Pressure Relief Valves	3.20E-05
OIL	ALL	Heavy Liquid	Pump Seals	3.20E-05
OIL	ALL	Heavy Liquid	Valves	8.40E-06
OIL	ALL	Light Liquid	Connectors	1.90E-04
OIL	ALL	Light Liquid	Control Valves	1.75E-02
OIL	ALL	Light Liquid	Open-Ended Lines	3.71E-03
OIL	ALL	Light Liquid	Pressure Relief Valves	7.50E-02
OIL	ALL	Light Liquid	Pump Seals	2.32E-02
OIL	ALL	Light Liquid	Valves	1.21E-03

Footnotes:

<sup>a</sup> Emission Factor – the average total hydrocarbon (THC) emissions for all components of the specified type. The factor takes into account the fact that only very few components have significant leak rates and the vast majority of components leak very little or not at all.

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## O&GP FG-03:

### EQUIPMENT LEVEL ESTIMATE OF FUGITIVE EMISSIONS FROM OIL AND GAS PRODUCTION INSTALLATIONS

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This method uses emission rates for large pieces of equipment rather than for their individual components. Equation 16e relies on emission factors for all of the equipment types in a facility, gas composition information, and equipment usage data to calculate fugitive emissions from individual pieces of equipment in O&GP activities. You can sum the results to calculate total emissions from a facility.

This approach involves four steps:

1. Identify the number and types of equipment employed throughout the facility;
2. Determine the appropriate mass emission factor for each piece of equipment;
3. Calculate CH<sub>4</sub> and CO<sub>2</sub> emissions for each piece of equipment; and
4. Convert CH<sub>4</sub> emissions to units of CO<sub>2</sub> equivalent and sum to determine total emissions.

#### STEP 1: IDENTIFY THE NUMBER AND TYPES OF EQUIPMENT EMPLOYED THROUGHOUT THE FACILITY.

---

Use a count that represents the actual inventory of all of the pieces of equipment that are in operation at a facility. This will include wellheads, pump stations, separators, heater treaters, headers, tanks, and small compressors.

#### STEP 2: DETERMINE THE APPROPRIATE MASS EMISSION FACTOR FOR EACH PIECE OF EQUIPMENT

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Table 16.4 provides a list of CH<sub>4</sub> emission factors for a variety of equipment types by oil and gas exploration and production equipment type.

**Table 16.4 – Equipment Level CH<sub>4</sub> Emission Rates by Industry and Facility Type<sup>22</sup>**

Facility Type / Equipment Type	Assumed CH <sub>4</sub> Content (molar %)	Emission Factor	Units
<b><i>Onshore Crude Production Facilities</i></b>			
Oil wellheads – heavy crude	78.8	6.63E-07	tonne/well-hr
Oil wellheads – light crude	78.8	1.56E-05	tonne/well-hr
Oil pump stations <sup>d</sup>	78.8	5.49E-08	tonne CH <sub>4</sub> /mile-hr
Separators – heavy crude	78.8	6.79E-07	tonne/separator-hr
Separators – light crude	78.8	4.10E-05	tonne/separator-hr
Heater treaters – light crude	78.8	4.77E-05	tonne/heater-hr
Headers – heavy crude	78.8	4.72E-07	tonne/header-hr
Headers – light crude	78.8	1.62E-04	tonne/header-hr
Tanks – light crude	78.8	2.75E-05	tonne/tank-hr
Small compressors – light crude	78.8	3.69E-05	tonne/compressor-hr
Large compressors <sup>e</sup> – light crude	78.8	1.31E-02	tonne/compressor-hr
Sales areas	78.8	3.24E-05	tonne/area-hr
<b><i>Onshore Natural Gas Production Facilities</i></b>			
Gas wellheads	78.8	1.80E-05	tonne CH <sub>4</sub> /well-hr
Separators	78.8	4.42E-05	tonne CH <sub>4</sub> /separator-hr
Gas heaters	78.8	4.60E-05	tonne CH <sub>4</sub> /heater-hr
Small reciprocating gas compressor	78.8	2.12E-04	tonne CH <sub>4</sub> /compressor-hr
Large reciprocating gas compressor	78.8	1.22E-02	tonne CH <sub>4</sub> /compressor-hr
Large reciprocating gas compressor stations	78.8	6.59E-03	tonne CH <sub>4</sub> /station-hr
Meters/piping	78.8	3.52E-05	tonne CH <sub>4</sub> /meter-hr
Dehydrators	78.8	7.13E-05	tonne CH <sub>4</sub> /dehydrator-hr
Gathering pipelines	78.8	4.28E-05	tonne CH <sub>4</sub> /mile-hr
CO <sub>2</sub> from oxidation	78.8	4.38E-06	tonne CO <sub>2</sub> /mile-hr
CO <sub>2</sub> from pipeline leaks	78.8	5.84E-06	tonne CO <sub>2</sub> /mile-hr
<b><i>Gas Processing Facilities</i></b>			
Gas processing volume	86.8	2.50E-03	tonne/MMscf processed
Reciprocating compressors	86.8	8.95E-03	tonne/compressor-hr
Centrifugal compressors	86.8	1.70E-02	tonne/compressor-hr

If you have site-specific information about the CH<sub>4</sub> content of the natural gas being processed, you can adjust the emission factors provided in Table 16.4 to reflect your own natural gas composition. You can do this by multiplying the emission factors from Table 16.4 by the ratio of CH<sub>4</sub> content of your own gas to the default CH<sub>4</sub> content values contained in Table 16.4, as shown in Equation 16.c.

<sup>22</sup> API 2009. "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry," Prepared for American Petroleum Institute (API), Prepared by URS Corp., August 2009, Tables 6-3 – 6-5.

You should collect and analyze natural gas composition data according to applicable industry-approved, national, or international technical standards regarding sampling frequency, procedures, and preparation such as:

- ASM D 2650: Standard Test Method for Chemical Composition of Gases by Mass Spectrometry
- ASTM D1945-03: Standard Test Method for Analysis of Natural Gas by Gas Chromatography
- ASTM D4984–06: Standard Test Method for Carbon Dioxide in Natural Gas Using Length-of-Stain Detector Tubes

**Equation 16c: Correcting Default CH<sub>4</sub> Emission Factors to Reflect Site-Specific CH<sub>4</sub> Content**

$$EF_{CH_4 site} = (EF_{CH_4 GD default}) \times (CH_4 site / CH_4 default)$$

where;

$EF_{CH_4 site}$  = Updated CH<sub>4</sub> emission factor, adjusted for site-specific CH<sub>4</sub> content of natural gas (tonnes/activity unit)

$EF_{CH_4 GD default}$  = Industry-specific CH<sub>4</sub> emission factor provided in Table 16.3 (tonnes/activity unit)

$CH_4 site$  = Site-specific CH<sub>4</sub> content provided by Member (molar %)

$CH_4 default$  = Segment-specific CH<sub>4</sub> content provided in Table 16.4 (molar %)

Generally, CO<sub>2</sub> emission factors are less commonly available than CH<sub>4</sub> emission factors. An equivalent CO<sub>2</sub> emission factor can, however, be calculated from a CH<sub>4</sub> emission factor based on the relative concentrations of CO<sub>2</sub> and CH<sub>4</sub> in the natural gas stream in question. This conversion is shown in Equation 16d below.

**Equation 16d: CH<sub>4</sub> to CO<sub>2</sub> Emission Factor Conversion**

$$EF_{CO_2} = EF_{CH_4} \times (44/16) \times (mol \% CO_2 / mol \% CH_4)$$

where;

$EF_{CO_2}$  = CO<sub>2</sub> emission factor

$EF_{CH_4}$  = CH<sub>4</sub> emission factor

44 = Molecular weight of CO<sub>2</sub> (g/mole)

16 = Molecular weight of CH<sub>4</sub> (g/mole)

$mol \% CO_2$  = Concentration of CO<sub>2</sub> in the natural gas stream (molar %)

$mol \% CH_4$  = Concentration of CH<sub>4</sub> in the natural gas stream (molar %)

### STEP 3: CALCULATE CH<sub>4</sub> AND CO<sub>2</sub> EMISSIONS FOR EACH PIECE OF EQUIPMENT

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Using the values obtained in steps 1-2 above; calculate total CH<sub>4</sub> and CO<sub>2</sub> emissions from all pieces of equipment using Equation 16e below.

#### Equation 16e: Calculating CO<sub>2</sub> and CH<sub>4</sub> Emissions from Exploration and Production Facilities Based on Equipment Level Emission Factors

$$E_{CH_4/CO_2} = \sum ER_i \times t_{annual\ i}$$

where:

$E_{CH_4/CO_2}$  = the total fugitive emissions of CH<sub>4</sub> or CO<sub>2</sub> from each facility (tonne/yr)

$ER_i$  = CH<sub>4</sub> or CO<sub>2</sub> emission factor from equipment type i (tonnes/hr)

$t_{annual\ i}$  = the annual usage of equipment type i (hr/yr)

### STEP 4: CONVERT CH<sub>4</sub> EMISSIONS TO UNITS OF CO<sub>2</sub> EQUIVALENT.

---

To convert CH<sub>4</sub> emissions to tonnes of CO<sub>2</sub>-e, multiply the quantity of CH<sub>4</sub> calculated in Step 3 by its GWP (21). Sum all values to determine the total emissions from facilities in tonnes CO<sub>2</sub>-e.

#### O&GP FG-04:

#### FACILITY LEVEL ESTIMATE OF FUGITIVE EMISSIONS FROM OIL AND GAS PRODUCTION INSTALLATIONS

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This method uses emission rates for entire facilities rather than for their individual components or pieces of equipment. Equation 16f relies on emission factors for the facility type, gas composition information, and production data to calculate fugitive emissions from O&GP installations.

This approach involves three steps:

1. Determine the appropriate mass emission factor for each facility type;
2. Calculate CH<sub>4</sub> and CO<sub>2</sub> emissions for each facility; and
3. Convert CH<sub>4</sub> emissions to units of CO<sub>2</sub> equivalent and sum to determine total emissions.

### STEP 1: DETERMINE THE APPROPRIATE MASS EMISSION FACTOR FOR EACH FACILITY TYPE

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Table 16.5 contains a list of CH<sub>4</sub> emission factors for different O&GP facility types.

**Table 16.5 – Equipment Level CH<sub>4</sub> Emission Rates by Facility Type<sup>23</sup>**

Facility Type	Assumed CH <sub>4</sub> Content (molar %)	Emission Factor
Onshore Oil Production	78.8	2.346E-04 tonnesCH <sub>4</sub> /bbl produced
Offshore Oil Production	78.8	9.386E-05 tonnesCH <sub>4</sub> /bbl produced
Onshore Gas Production	78.8	2.601E-02 tonnesCH <sub>4</sub> /MMscf
Offshore Gas Production	78.8	1.040E-02 tonnesCH <sub>4</sub> /MMscf
Gas Processing	86.8	2.922E-02 tonnesCH <sub>4</sub> /MMscf

If you have site-specific information on the CH<sub>4</sub> content of the natural gas being processed, follow the method to adjust the default emission factor using the guidance provided in Step 2 of FG-03.

If facility-level information about CO<sub>2</sub> emissions are not available, use equation 16d to calculate a CO<sub>2</sub> emission factor based on the relative concentrations of CO<sub>2</sub> and CH<sub>4</sub> in the natural gas stream in question.

## STEP 2: CALCULATE CH<sub>4</sub> AND CO<sub>2</sub> EMISSIONS FOR EACH FACILITY

Using the emission factor obtained in Step 1, above, you can calculate total CH<sub>4</sub> and CO<sub>2</sub> emissions from each facility using Equation 16f below.

### Equation 16f: Calculating CO<sub>2</sub> and CH<sub>4</sub> Emissions from Exploration and Production Facilities Based on Facility Level Emission Factors

$$E_{CH_4/CO_2} = ER_{CH_4/CO_2i} \times t_{annuali}$$

where:

$E_{CH_4/CO_2}$  = the total fugitive emissions of CH<sub>4</sub> or CO<sub>2</sub> from each facility (tonne/yr)

$ER_{CH_4/CO_2i}$  = CH<sub>4</sub> or CO<sub>2</sub> emission factor from facility type i (tonnes/bbl produced)

$t_{annuali}$  = Facility production data (bbl/yr)

<sup>23</sup> API 2009. "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry," Prepared for American Petroleum Institute (API), Prepared by URS Corp., August 2009, Tables 6-2.

### STEP 3: CONVERT CH<sub>4</sub> EMISSIONS TO UNITS OF CO<sub>2</sub> EQUIVALENT.

---

To convert CH<sub>4</sub> emissions to tonnes of CO<sub>2</sub>-e, multiply the quantity of CH<sub>4</sub> calculated in Step 2 by its GWP (21). Sum all values to determine the total emissions from facilities in tonnes CO<sub>2</sub>-e.

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#### 16.2 Surface Collection Ponds

Water disposal pits are used to store and dispose of produced water or fluids from drilling and completion operations. The water in these pits may contain small amounts of hydrocarbons that may volatilize into the atmosphere if no other control measures are taken. These pits have GHG emissions of CH<sub>4</sub> but can also have emissions of CO<sub>2</sub> if it is present in the water. While produced water is typically re-injected to enhance oil and gas recovery, varying amounts of the produced water remain in the collection ponds and any CO<sub>2</sub> or CH<sub>4</sub> dissolved in it, evaporate into the atmosphere.

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O&GP FG-05:

#### MASS FRACTION CALCULATION

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You may use Equation 16i to calculate the quantities of CO<sub>2</sub> and CH<sub>4</sub> that are released from produced water left to evaporate in disposal pits. It should be noted that all of the gas dissolved in this water is assumed to be released into the atmosphere.

Equation 16g: Gas Emitted from Non Re-injected Produced Waters <sup>24</sup>
$E_{CO_2/CH_4} = f_i \times Q_{water}$
Where
$E_{CO_2/CH_4}$ = Emissions of CO <sub>2</sub> or CH <sub>4</sub> from the non re-injected water (tonnes)
$f_i$ = mass fraction of CH <sub>4</sub> or CO <sub>2</sub> in the water (%)
$Q_{water}$ = mass of non-re-injected water (tonnes)

For additional guidance on measuring the CO<sub>2</sub> content of produced water, refer to:

- ASTM D513–06: Standard Test Methods for Total and Dissolved Carbon Dioxide in Water

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#### 16.3 Oil Pump Stations

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<sup>24</sup> "Greenhouse Gas Emission Reduction Protocol for the Salt Creek Enhanced Oil Recovery (EOR) Project". Howell Petroleum Corporation. August, 2004

Pump stations are used in crude oil lines. These stations are located along the line to move the product through the pipeline. Their location is defined by the topography of the terrain, the type of product being transported, or operational conditions of the network.

This section describes quantification methods to quantify fugitive emissions from oil pump stations.

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O&GP FG-06:

## FUGITIVE EMISSIONS ESTIMATION FROM PUMP STATIONS

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Once crude oil reaches atmospheric pressure and the volatile CH<sub>4</sub> has flashed off, the crude is considered 'weathered' or stabilized. Unless site-specific data indicate otherwise, 'weathered' crude is assumed to have no CH<sub>4</sub>.<sup>25</sup>

In the case where you have site-specific data, you should refer to O&GP FG-01 to quantify fugitive emissions from pump stations.

Equation 16-1 relies on the measurement or estimation of the fugitive mass emissions rate of gas.

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<sup>25</sup> Refer to API Compendium 2009, Appendix E for more information on the CH<sub>4</sub> content of 'weathered' crude and other petroleum products.

## Chapter 17 Direct Process Emissions

This chapter describes quantification methodologies for process emissions that are unique to the O&GP sector. Table 17.1 lists the Registry-approved calculation methods and each method's data requirements.

**Table 17.1 – Calculation Methods Included in Chapter 17 of the O&GP Protocol**

Method	Data Requirements
O&GP PR-01	Emission rate of CH <sub>4</sub> and CO <sub>2</sub> , Annual usage of each unit, Quantity of treated gas produced, Volume of treated and untreated gas, Molecular weight of CO <sub>2</sub>
O&GP PR-02	Emission rate of CH <sub>4</sub> and CO <sub>2</sub> , Annual usage of each unit, Quantity of treated gas produced, Volume of treated and untreated gas, Molecular weight of CO <sub>2</sub> , Pressure and Temperature
O&GP PR-03	Quantity of treated gas produced, Emission factor for CH <sub>4</sub>
O&GP PR-04	Emission rate of CH <sub>4</sub> and CO <sub>2</sub> , Annual usage of each unit, Quantity of treated gas produced, Volume of treated and untreated gas, Molecular weight of CO <sub>2</sub>
O&GP PR-05	Emission rate of CH <sub>4</sub> and CO <sub>2</sub> , Annual usage of each unit, Gas composition and flow rate, Wet gas temperature and pressure, Glycol circulation rate, Temperature and pressure in the absorber column, Type of glycol pump used, Operating pressure of the flash tank, Stripping gas usage, Amount of flash gas used in the process, Molecular weight of CO <sub>2</sub> and CH <sub>4</sub>
O&GP PR-06	Gas composition and flow rate, wet gas temperature, pressure, and water content, glycol circulation rate, temperature and pressure in the absorber column, the type of glycol pump used, the operating pressure of the flash tank (if used), the amount of flash gas used by the process (if used), the type of glycol (TEG or DEG) used, and stripping gas usage (if used).
O&GP PR-07	Molar fraction of GHG, Emission factor of CH <sub>4</sub> and CO <sub>2</sub> , Emission rate of gas from dehydrator type, molar fraction of CH <sub>4</sub> or CO <sub>2</sub> in the gas, quantity of natural gas processed annually, number of dehydrators for production segment
O&GP PR-08	Measured CH <sub>4</sub> emission rate from each glycol dehydrator, the annual usage of each glycol dehydrator
O&GP PR-09	Molecular weight of CH <sub>4</sub> and CO <sub>2</sub> , Total volume of gas vented, Molar fraction of GHG
O&GP PR-10	Emission factor of CH <sub>4</sub> and CO <sub>2</sub> , Number of drilling per year
O&GP PR-11	Volume of gas vented due to completion activities, CH <sub>4</sub> Emission factor
O&GP PR-12	Emission factor for CH <sub>4</sub> and CO <sub>2</sub> , Molar fraction of GHG, Volume of gas vented, Molecular weight of CH <sub>4</sub> and CO <sub>2</sub> , Casing diameter, Well depth, Shut-in pressure
O&GP PR-13	Molar fraction of CH <sub>4</sub> and CO <sub>2</sub> , Number of events per year, Molecular weight of CH <sub>4</sub> and CO <sub>2</sub> , Compressibility factor, Absolute temperature
O&GP PR-14	Annual event occurrences, or production data, Emission factor for CH <sub>4</sub> and CO <sub>2</sub> , Molecular weight of CH <sub>4</sub> and CO <sub>2</sub>
O&GP PR-15	Crude oil loading volume, Average emission factor per component type, Average weight fraction of TOC, CH <sub>4</sub> or CO <sub>2</sub>

Method	Data Requirements
O&GP PR-16	Temperature of the vapors, True pressure of crude oil loaded, Vapor growth factor, Saturation factor, Molecular weight of CH <sub>4</sub> and CO <sub>2</sub> , Average weight fraction of TOC, Crude oil loading volume, Emission factor for CH <sub>4</sub> and CO <sub>2</sub>
O&GP PR-17	Saturation factor, Molecular weight of CH <sub>4</sub> and CO <sub>2</sub> , Temperature, Pressure, Control efficiency
O&GP PR-18	Emission factor for CH <sub>4</sub> and CO <sub>2</sub> , Volume of ballast water, Volume of crude oil transported, Ullage, Crude oil RVP, CH <sub>4</sub> content of the vapors
O&GP PR-19	TOC Emission factor, Activity factor (i.e. annual ballast water throughput)
O&GP PR-20	Molar fraction of GHG, Volume of gas vented, Compressibility factor, Process temperature and pressure, Molecular weight of CH <sub>4</sub> and CO <sub>2</sub> , Emission factor for CH <sub>4</sub> and CO <sub>2</sub> , Pipeline length, Volume factor
O&GP PR-21	Storage tank annual throughput, Hydrocarbon vapor emissions rate, GHGs density, Separator Temperature, Separator Pressure, API gravity, Gas specific gravity, Volume of produced oil, VOC fraction of tank emissions, Molecular weight of stock tank gas
O&GP PR-22	Tank configuration, API gravity and Reid Vapor Pressure (RVP) of the sales oil, separator pressurized oil composition, separator pressure and temperature, and production rate of liquid to tanks
O&GP PR-23	Extended pressurized condensate or oil analysis; temperature, pressure and flow rates for the process being simulated
O&GP PR-24	API gravity of liquid hydrocarbon at final condition, Pressure and Temperature, Specific gravity of the tank flash gas, Oil production volume
O&GP PR-25	API gravity, pressure, oil production volume
O&GP PR-26	Oil production volume , Emissions factors for CO <sub>2</sub> , and CH <sub>4</sub> ,
O&GP PR-27	Concentrations of CO <sub>2</sub> , and CH <sub>4</sub> , Temperature, Pressure, API gravity,
O&GP PR-28	Number of devices per basin or region, Bleed rate of gas, Annual usage of pneumatic device, Molecular weight of CH <sub>4</sub> and CO <sub>2</sub> , Emissions factors for CO <sub>2</sub> , and CH <sub>4</sub>
O&GP PR-29	Number of CIPs in the basin or region, Emission rate of gas, Molecular weight of the natural gas (lb/lb-mole), Annual usage of CIP
O&GP PR-30	Feedstock rate, weight fraction of carbon in feedstock, molecular weight of CO <sub>2</sub> and C
O&GP PR-31	Molecular weight of CO <sub>2</sub> , and CH <sub>4</sub> , Weight fraction of carbon feedstock, Feedstock rate, Rate of hydrogen production
O&GP PR-32	Mass of limestone, Weight percent of CaCO <sub>3</sub> , Conversion factor for CO <sub>2</sub> equivalency
O&GP PR-33	Emission factors for mine surfaces, Total surface area, Length of time the oil sands surface have been exposed, Oil sands feed grade (weight percent bitumen)

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## 17.1 Amine Plant Process Venting

This section describes a method for calculating CH<sub>4</sub> and CO<sub>2</sub> emissions from amine units. In addition to water, oil, and NGL removal, one of the most important parts of gas processing involves the removal of acid gases from natural gas streams. Amine units are often employed to remove the acid gases hydrogen sulfide and CO<sub>2</sub> through the amine process in which a stream of natural gas is passed through an amine solution, which absorbs the gases. The amine solution is then directed to an amine regenerator, where a reboiler supplies the necessary heat to strip H<sub>2</sub>S and CO<sub>2</sub> from the rich amine. Elemental sulfur is often recovered in a separate sulfur recovery unit.

This section addresses CH<sub>4</sub> emissions from uncontrolled amine unit vents, and CO<sub>2</sub> from amine unit and sulfur recovery vents. Combustion emissions from reboiler units and emissions associated with flared or captured and utilized vented emissions are addressed in Chapter 12. Direct Emissions from Stationary Combustion.

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O&GP PR-01:

### CALCULATING CH<sub>4</sub> AND CO<sub>2</sub> EMISSIONS FROM AMINE UNITS BASED ON TESTS OF AMINE UNIT VENT EMISSIONS

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This method relies on a direct measurement of the CH<sub>4</sub> and CO<sub>2</sub> content of the gas stream released from the amine unit vent. Amine unit vent emissions should be analyzed for CH<sub>4</sub> and CO<sub>2</sub> content, measured in scfd. This method is used to measure the CO<sub>2</sub> and CH<sub>4</sub> released to the atmosphere. You should collect and analyze emissions according to applicable industry-approved, national, or international technical standards regarding sampling frequency, procedures, and preparation. For additional resources on measuring the emissions from amine units, refer to:

- ASTM D 2650: Standard Test Method for Chemical Composition of Gases by Mass Spectrometry

CH<sub>4</sub> and CO<sub>2</sub> emissions from each measured amine unit can then be calculated using Equation 17a below.

**Equation 17a: Calculating CO<sub>2</sub> and CH<sub>4</sub> Emissions from Amine Units Based on Tests of Amine Unit Vent Emissions**

$$E_{CH_4/CO_2} = ER_{CH_4/CO_2} \times lbmole/379.3scf \times t_{annual} \times (1/2204.62)$$

where;

$E_{CH_4/CO_2}$  = the total venting emissions of CH<sub>4</sub> or CO<sub>2</sub> from each amine unit (tonne/yr)

$ER_{CH_4/CO_2}$  = measured CH<sub>4</sub> or CO<sub>2</sub> emission rate from each amine unit (scfd)

$lbmole/379.3scf$  = conversion factor from scf to lb

$t_{annual}$  = the annual usage of each amine unit (days/yr)

$1/2204.62$  = conversion factor from lb to tonnes

To convert CH<sub>4</sub> emissions to tonnes of CO<sub>2</sub>-e, multiply the quantity of CH<sub>4</sub> calculated by its GWP (21). Sum all values to determine the total emissions from all amine units in tonnes CO<sub>2</sub>-e.

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O&GP PR-02:

#### METHOD FOR CALCULATING CH<sub>4</sub> EMISSIONS FROM AMINE UNITS USING API'S AMINECALC SOFTWARE

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If measured test data from amine units are not available, you can use a software program, such as API's AMINECalc Software to calculate organic compound emissions from amine units. AMINECalc is a software tool designed to estimate hydrocarbon emissions from amine and other natural gas sweetening units. Data required to run the software includes information on CH<sub>4</sub> composition ("C1") as an input and also includes it in the software output (see figure below). More information on using the AMINECalc model can be found on API's website.<sup>26</sup>

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<sup>26</sup> [www.api.org](http://www.api.org). AMINECalc software and documentation can be found by searching for publication number 4679.

Figure 17.1 – AMINECalc Model Input Screen

Component	Mole %
1 H2S	2.0000
2 CO2	6.0000
3 DEA	0.0000
4 H2O	0.0000
5 N2	0.0000
6 O2	0.0000
7 C1	92.0000
8 C2	0.0000

An estimate of VOC mass emission rate is one of AMINECalc's outputs. Provided you have knowledge of the CH<sub>4</sub> content of the natural gas being processed, you can convert this to a mass emission rate for CH<sub>4</sub>. If you do not have access to the CH<sub>4</sub> content of the input gas, you can assume a default molar fraction value of 0.868.<sup>27</sup>

O&GP PR-03:

#### METHOD FOR CALCULATING CH<sub>4</sub> EMISSIONS FROM AMINE UNITS USING GENERAL EMISSION FACTORS

If the data required to use the previous methods are unavailable, you can use a general emission factor of 0.0185 tonnes CH<sub>4</sub>/10<sup>6</sup> scf treated gas produced, as shown in Equation 17b. This factor is based on an uncontrolled, diethanol amine unit, and does not include any emissions of CO<sub>2</sub>.<sup>28</sup>

<sup>27</sup> API 2009. "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry," Prepared for American Petroleum Institute (API), Prepared by URS Corp., August 2009. Table 5-15.

<sup>28</sup> API 2009. "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry," Prepared for American Petroleum Institute (API), Prepared by URS Corp., August 2009. Table 5-5.

**Equation 17b: Calculating CH<sub>4</sub> Emissions from Amine Units using Emission Factors**

$$E_{CH_4} = ER_{CH_4} \times Gas\ annual$$

where:

$E_{CH_4}$  = the total venting emissions of CH<sub>4</sub> from each amine unit (tonne/yr)

$ER_{CH_4}$  = default CH<sub>4</sub> emission rate from each amine unit (0.0185 tonnes CH<sub>4</sub>/10<sup>6</sup> treated gas produced annually)

$Gas\ annual$  = quantity of treated gas produced annually (10<sup>6</sup> scf)

O&GP PR-04:

**METHOD FOR CALCULATING CO<sub>2</sub> EMISSIONS FROM AMINE UNITS USING A MATERIAL BALANCE APPROACH**

You can measure CO<sub>2</sub> emissions from amine and sulfur recovery units that vent their emissions directly to the atmosphere by using a material balance method that measures the concentration of CO<sub>2</sub> in both the inlet stream into the unit and the outlet gas stream coming out of it. This method subtracts the gas exiting the unit (but not released into the atmosphere) from the gas going into the unit. This approach is outlined in Equation 17c, below. For guidance on measuring the CO<sub>2</sub> content of the inlet and outlet streams, refer to:

- ASTM D 2650: Standard Test Method for Chemical Composition of Gases by Mass Spectrometry

**Equation 17c: Calculating CO<sub>2</sub> Emissions from Amine Units Using Mass Balance**

$$E_{CO_2} = [(V_{inlet} \times C_{CO_2\ inlet}) - (V_{outlet} \times C_{CO_2\ outlet})] \times (44/23.685\text{m}^3/\text{kgmole}) \times 2204.62$$

where;

$E_{CO_2}$  = the total venting emissions of CO<sub>2</sub> from each amine unit (tonne/yr)

$V_{inlet}$  = volume of untreated inlet gas (m<sup>3</sup>)

$C_{CO_2\ inlet}$  = CO<sub>2</sub> concentration of untreated inlet gas (molar %)

$V_{outlet}$  = volume of treated outlet gas (m<sup>3</sup>)

$C_{CO_2\ outlet}$  = CO<sub>2</sub> concentration of treated outlet gas (molar %)

44 = molecular weight of CO<sub>2</sub>

23.685 = CO<sub>2</sub> molar conversion factor

If CH<sub>4</sub> emissions from the vented CO<sub>2</sub> are not measured, you can assume a default concentration of one percent CH<sub>4</sub> in the vented CO<sub>2</sub> you quantify through direct measurement or by using equation 17c above.

## 17.2 Dehydrators

This section contains methods for calculating vented emissions from liquid desiccant dehydrators, primarily glycol dehydrators, in use at wellheads and central gas processing facilities. Dehydrators are used to remove the water contained in produced natural gas, which can condense and/or freeze in gathering, transmission and distribution piping causing plugging, pressure surges and corrosion. This is done by passing the natural gas through a dewatering agent such as triethylene glycol (TEG), diethylene glycol (DEG) or propylene carbonate. The glycol stream is then passed through a glycol reboiler/regenerator, where water and hydrocarbons are boiled off.

Factors that affect emission rates include the gas flow rate, the inlet and outlet water content, glycol-to-water ratios, the percent over circulation and the methane entrainment rate.

In uncontrolled systems, CH<sub>4</sub> that is stripped from the glycol stream, contained in the stripping gas and vented from natural gas driven glycol pumps is vented to the atmosphere from the glycol regenerator. In some systems, these emissions are flared, or directed to an alternative controlled combustion device and utilized. Similarly, emissions from flash separators may also either be vented to the atmosphere or collected for use or flaring.

Considerations for accounting for stripping gases, natural gas driven glycol pumps and gas capture are discussed as appropriate to each method below. At sites where the natural gas has a naturally occurring CO<sub>2</sub> content, CO<sub>2</sub> emissions from these sources might also be significant. EOR operations using CO<sub>2</sub> can result in high natural gas CO<sub>2</sub> concentrations. Combustion emissions from the glycol regenerators and emissions associated with flared or captured and utilized vented emissions are addressed in Chapter 12. Direct Emissions from Stationary Combustion.

O&GP PR-05:

METHOD FOR CALCULATING CH<sub>4</sub> AND CO<sub>2</sub> EMISSIONS FROM GLYCOL DEHYDRATORS BASED ON TESTS OF DEHYDRATOR VENT EMISSIONS

This method relies on a direct measurement of the CH<sub>4</sub> and CO<sub>2</sub> content of the gas stream released from the glycol dehydrator vent. You should analyze dehydrator regenerator vent emissions for CH<sub>4</sub> and CO<sub>2</sub> content, measured in scfd. You should collect and analyze emissions according to applicable industry-approved, national, or international technical standards regarding sampling frequency, procedures, and preparation. For additional resources on measuring the emissions from glycol dehydrators, refer to:

- ASTM D 2650: Standard Test Method for Chemical Composition of Gases by Mass Spectrometry

You can calculate CH<sub>4</sub> and CO<sub>2</sub> emissions from each measured glycol dehydrator using Equation 17d below.

Equation 17d: Calculating CO <sub>2</sub> and CH <sub>4</sub> Emissions from Glycol Dehydrators Based on Tests of Dehydrator Vent Emissions
$E_{CH_4/CO_2} = ER_i \times lbmole/379.3scf \times t_{annual} \times (1/2204.62)$
<p>where:</p> <p><math>E_{CH_4/CO_2}</math> = the total venting emissions of CH<sub>4</sub> or CO<sub>2</sub> from each glycol dehydrator (tonne/yr)</p> <p><math>ER_i</math> = measured CH<sub>4</sub> or CO<sub>2</sub> emission rate from each glycol dehydrator (scfd)</p> <p><math>lbmole/379.3scf</math> = conversion factor from scf to lb</p> <p><math>t_{annual}</math> = the annual usage of each amine unit (days/yr)</p> <p><math>1/2204.62</math> = conversion factor from lb to tonnes</p>

To convert CH<sub>4</sub> emissions to tonnes of CO<sub>2</sub>-e, multiply the quantity of CH<sub>4</sub> calculated by its GWP (21). Sum all values to determine the total emissions from glycol dehydrators in tonnes CO<sub>2</sub>-e.

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O&GP PR-06:

### METHOD FOR CALCULATING CH<sub>4</sub> EMISSIONS FROM GLYCOL DEHYDRATORS USING GTI'S GRI-GLYCALC SOFTWARE

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If you do not have measured test data from each dehydrator, you can use GTI's GRI-GLYCalc software to calculate emissions of CH<sub>4</sub>, and other organic compounds. GRI-GLYCalc requires detailed information about each dehydrator for which emissions are calculated, including gas composition and flow rate, wet gas temperature, pressure, and water content, glycol circulation rate, temperature and pressure in the absorber column, the type of glycol pump used, the operating pressure of the flash tank, the amount of flash gas used by the process, the type of glycol (TEG or DEG) used, and stripping gas usage. More information on using the GRI-GLYCalc model can be found on GTI's website.<sup>29</sup>

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O&GP PR-07:

### METHOD FOR CALCULATING CH<sub>4</sub> AND CO<sub>2</sub> EMISSIONS FROM GLYCOL DEHYDRATORS USING INDUSTRY SEGMENT SPECIFIC EMISSION FACTORS

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This method relies on emission factors for dehydrators, total natural gas processing estimates, CH<sub>4</sub> and CO<sub>2</sub> content estimates, and dehydrator counts to calculate CH<sub>4</sub> and CO<sub>2</sub> emissions from glycol dehydrators in the production segment of the natural gas industry. Some dehydrator systems will include a flash tank separator and/or a natural gas-driven glycol pump. If either of these items is present, you must adjust the emission factor for the dehydrator accordingly. These adjustments are outlined in Step 3, below.

This approach involves five steps:

1. Identify the number of dehydrators employed;
2. Identify the total quantity of natural gas processed;
3. Determine the appropriate emission rate for each dehydrator;
4. Calculate CH<sub>4</sub> and CO<sub>2</sub> emissions for each dehydrator; and
5. Convert CH<sub>4</sub> emissions to units of CO<sub>2</sub> equivalent and sum to determine total emissions.

#### STEP 1: IDENTIFY THE NUMBER OF DEHYDRATORS EMPLOYED.

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Use a count that represents the actual inventory of all of the glycol dehydrators that are in operation at the all of the facilities in your installation by industry segment.

#### STEP 2: IDENTIFY THE TOTAL QUANTITY OF NATURAL GAS PROCESSED

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Obtain an estimate for the total quantity of natural gas that is processed in each industry segment, in 10<sup>6</sup> scf/year.

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<sup>29</sup> <http://www.gastechnology.org/webroot/app/xn/xd.aspx?it=enweb&xd=10abstractpage12352.xml>

### STEP 3: DETERMINE THE APPROPRIATE EMISSION RATE FOR EACH DEHYDRATOR

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Calculating emission rates for dehydrators is a one to three step process, depending on the type of dehydrator in question, and on data availability. For each dehydrator type, you must a) select an emission factor from the appropriate industry segment, b) correct the emissions factor by adding an emissions factor for a natural-gas driven glycol pump, if present, and c) correct the resulting emissions factor to reflect the composition of the natural gas being processed, if data availability allows. This is illustrated in Equation 17e.

Table 17.2 contains a list of emission factors for a variety of dehydrators by industry segment. It does not include emissions from natural gas-driven glycol pumps. For each segment, the assumed CH<sub>4</sub> content used to generate the segment-specific emission factor is provided.

**Table 17.2 – CH<sub>4</sub> Emission Rates for Glycol Dehydrators by Natural Gas Industry Segment<sup>30</sup>**

Industry Segment	CH <sub>4</sub> Emission Factor (tonnes / 10 <sup>6</sup> scf gas processed annually)	CH <sub>4</sub> Content Basis for Industry Segment (molar %)
Production	0.0052859	78.8
Processing	0.0023315	86.8

Note: This table does not include Glycol Gas-Assisted Pump Emissions – See Table 17.3.

For dehydrators that use natural gas-driven glycol circulator pumps, you must adjust the emissions rates from Table 17.2, above, to reflect the additional CH<sub>4</sub> emissions from the pump. If you know the emissions rate of your specific glycol pump, use that. If you do not have information about the specific pumps you are using, Table 17.3 contains emission factors for glycol pumps in dehydrators in the production and processing segments.<sup>31</sup> However, it should be noted that the amount of CH<sub>4</sub> absorbed by the glycol and subsequently released from the regenerator varies non-linearly with the concentration of CH<sub>4</sub> in the wet gas. Therefore, The Registry recommends that you obtain information about the pumps you are using.

<sup>30</sup> API 2009. “Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry,” Prepared for American Petroleum Institute (API), Prepared by URS Corp., August 2009, Table 5-2.

<sup>31</sup> Based on pumps produced by Kimray, Inc, a leading manufacturer of glycol pumps.

**Table 17.3 – CH<sub>4</sub> Emission Rates for Natural Gas-Driven Glycol Pumps by Natural Gas Industry Segment<sup>32</sup>**

Industry Segment	CH <sub>4</sub> Emission Factor (tonnes / 10 <sup>6</sup> scf gas processed annually)	CH <sub>4</sub> Content Basis for Industry Segment (molar %)
Production	0.01903	78.8
Processing	0.0034096	86.8

If a flash tank is in use, you must also adjust the emission rate to account for it.<sup>33</sup> All emissions that are vented to the atmosphere from the flash tank must be added to the emission rates provided in Table 17.3. To calculate emissions from flash tanks on a comparable basis, divide the total quantity of CH<sub>4</sub> emitted from the flash tank by the total quantity of natural gas processed on an annual basis to convert to a tonnes CH<sub>4</sub>/10<sup>6</sup> scf processed annually basis. If the emissions from the flash tank are collected and flared or rerouted for use as a fuel in the glycol regenerator boiler or elsewhere, they must be accounted for separately using the methods provided in Chapter 12.

If you have site-specific information on the CH<sub>4</sub> content of the natural gas being processed, you can adjust the emission factors provided in Table 17.2 and Table 17.3 to reflect your own natural gas composition. You can do this by multiplying the emission factors from Table 17.2 and Table 17.3 by the ratio of CH<sub>4</sub> content of your own gas to the default CH<sub>4</sub> content values also provided in Table 17.2 and Table 17.3, as shown in Equation 17e.

You should collect and analyze natural gas composition data according to applicable industry-approved, national, or international technical standards regarding sampling frequency, procedures, and preparation. For additional resources on gas composition analysis methods, refer to:

- ASTM D1945-03: Standard Test Method for Analysis of Natural Gas by Gas Chromatography
- ASTM D4984–06: Standard Test Method for Carbon Dioxide in Natural Gas Using Length-of-Stain Detector Tubes

<sup>32</sup> API 2009. “Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry,” Prepared for American Petroleum Institute (API), Prepared by URS Corp., August 2009, Table 5-4.

<sup>33</sup> Glycol dehydrator emission factors provided in Table 17.2 reflect a national population with and without flash tanks (refer to Volume 14 of the 1996 GRI/EPA study, from which the emission factors were derived).

**Equation 17e: Correcting Default Dehydrator CH<sub>4</sub> Emission Factors to Account for Glycol Pumps, Flash Tank Separators, and Site-Specific CH<sub>4</sub> Content Values**

$$EF_{CH_4 site} = (EF_{CH_4 GD default} + EF_{CH_4 GP}) \times (CH_4 site / CH_4 default)$$

where;

$EF_{CH_4 site}$  = Updated CH<sub>4</sub> emission factor for dehydrators, adjusted for site-specific CH<sub>4</sub> content of natural gas (tonnes/scf processed)

$EF_{CH_4 GD default}$  = Segment-specific glycol dehydrator CH<sub>4</sub> emission factor provided in Table 17.3 (tonnes/scf processed)

$EF_{CH_4 GP}$  = Natural gas-driven glycol pump CH<sub>4</sub> emission factor, either site-specific, or provided in Table 17.3 (if used) (tonnes/scf processed)

$CH_4 site$  = Site-specific CH<sub>4</sub> content provided by Member (molar %)

$CH_4 default$  = Segment-specific CH<sub>4</sub> content provided in Table 17.3 (molar %)

You can calculate an equivalent CO<sub>2</sub> emission factor from a CH<sub>4</sub> emission factor based on the relative concentrations of CO<sub>2</sub> and CH<sub>4</sub> in the natural gas stream in question. This conversion is shown in Equation 17f, below.

**Equation 17f: CH<sub>4</sub> to CO<sub>2</sub> Emission Factor Conversion**

$$EF_{CO_2} = EF_{CH_4} \times (44/16) \times (mol \% CO_2 / mol \% CH_4)$$

where:

$EF_{CO_2}$  = CO<sub>2</sub> emission factor

$EF_{CH_4}$  = CH<sub>4</sub> emission factor

44 = Molecular weight of CO<sub>2</sub> (g/mole)

16 = Molecular weight of CH<sub>4</sub> (g/mole)

$mol \% CO_2$  = Concentration of CO<sub>2</sub> in the natural gas stream (molar %)

$mol \% CH_4$  = Concentration of CH<sub>4</sub> in the natural gas stream (molar %)

Step 4: Calculate CH<sub>4</sub> emissions for each device and sum to obtain total CH<sub>4</sub> emissions

Using the values obtained in steps 1-3, above; calculate total CH<sub>4</sub> and CO<sub>2</sub> emissions from all dehydrators using Equation 17g, below.

**Equation 17g: Calculating CO<sub>2</sub> and CH<sub>4</sub> Emissions from Glycol Dehydrators Based on Industry Segment Specific Emissions Factors**

$$E_{CH_4/CO_2} = N_i \times Q_{vent\ i} \times (1.0\ lb - mole / 379.3\ scf) \times MW_i \times f_i \times t_{annual\ i} / 2204.62$$

where;

$E_{CH_4/CO_2}$  = the total glycol dehydrator venting emissions of CH<sub>4</sub> or CO<sub>2</sub> from each industry segment (tonne/yr)

$N_i$  = the number of dehydrators for production segment  $i$  in the basin or region

$Q_{vent\ i}$  = the emission rate of gas from dehydrator type  $i$  (tonnes/10<sup>6</sup>scf gas processed)

$MW_i$  = the molecular weight of CH<sub>4</sub> or CO<sub>2</sub> (16 lb/lb-mole or 44 lb/lb-mole)

$f_i$  = is the molar fraction of CH<sub>4</sub> or CO<sub>2</sub> in the gas

$t_{annual}$  = quantity of natural gas processed annually (10<sup>6</sup> scf /yr)

1/2204.62 = conversion factor from lb to tonnes

**STEP 5: CONVERT CH<sub>4</sub> EMISSIONS TO UNITS OF CO<sub>2</sub> EQUIVALENT.**

To convert CH<sub>4</sub> emissions to tonnes of CO<sub>2</sub>-e, multiply the quantity of CH<sub>4</sub> calculated in Step 4 by its GWP (21). Sum all values to determine the total emissions from dehydrators in tonnes CO<sub>2</sub>-e.

**O&GP PR-08:**

**METHOD FOR CALCULATING CH<sub>4</sub> EMISSIONS FROM GLYCOL DEHYDRATORS USING GENERAL EMISSION FACTORS**

If you do not have the data required to use the previous methods, you can use the general emission factors provided in Table 17.4 to estimate CH<sub>4</sub> emissions from glycol dehydrators. These generalized emission factors were calculated using GTI's GRI-GLYCalc software. They include emissions from natural gas-driven glycol pumps and account for the presence or absence of a flash tank separator that collects and utilizes vented emissions.

You can calculate CH<sub>4</sub> emissions from each dehydrator by using Equation 17h.

**Equation 17h: Calculating CH<sub>4</sub> Emissions from Glycol Dehydrators Using General Emissions Factors**

$$E_{CH_4} = ER_{CH_4} \times lbmole/379.3scf \times t_{annual} \times (1/2204.62)$$

where:

$E_{CH_4}$  = the total venting emissions of CH<sub>4</sub> from each glycol dehydrator (tonne/yr)

$ER_{CH_4}$  = measured CH<sub>4</sub> emission rate from each glycol dehydrator (scfd)

$lbmole/379.3scf$  = conversion factor from scf to lb

$t_{annual}$  = the annual usage of each glycol dehydrator (days/yr)

$1/2204.62$  = conversion factor from lb to tonnes

**Table 17.4 – Generalized CH<sub>4</sub> Emission Rates for Glycol Dehydrators by Dehydrator Mode of Operation<sup>34</sup>**

Mode of Operation	CH <sub>4</sub> Emission Factor (tonnes / 10 <sup>6</sup> scf gas processed annually)
Gas pump without a flash separator	0.006410
Gas pump with a flash separator	0.000154
Electric pump without a flash separator	0.001665
Electric pump with a flash separator	0.000127

You must calculate CH<sub>4</sub> emissions for all dehydrators in use, and sum them to calculate total CH<sub>4</sub> emissions.

### 17.3 Well Completions, Underbalanced Drilling, and Drilling Mud Degassing

Well completion refers to the process of finishing a well so that it is ready to produce oil or natural gas. This process includes strengthening the well hole with casing, evaluating the pressure and temperature of the formation, and then installing the proper equipment to ensure an efficient flow out of the well. This methodology can also be applied to calculate vented emissions from underbalanced drilling operations, which is a procedure used to drill oil and gas wells where the pressure in the wellbore is kept lower than the fluid pressure in the formation being drilled. As the well is being drilled, formation fluid flows into the wellbore and up to the surface. This is the opposite of the usual situation, where the wellbore is kept at a pressure above the formation to prevent formation fluid entering the well.

Part of a well drilling operation is to keep the drilling mud free of entrained gas that enters the mud as it circulates downhole. This gas can reduce the drilling mud density causing the

<sup>34</sup> API 2009. "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry," Prepared for American Petroleum Institute (API), Prepared by URS Corp., August 2009, Table 5-3.

pressure in the well hole to drop and allowing the oil and/or gas to flow from the reservoir to the surface before the well completion is finished. Drilling mud degassing units extract the entrained gas from the mud at the surface. During this process CH<sub>4</sub> emissions are vented to the atmosphere.

This section contains methodologies to calculate GHG emissions from well completion, underbalanced drilling, and drilling mud degassing activities.

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O&GP PR-09:

## WELL COMPLETION AND UNDERBALANCED DRILLING EMISSIONS ESTIMATION METHODOLOGY

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You can calculate CO<sub>2</sub> and CH<sub>4</sub> emissions from well completion using the volume of gas vented and the methane fraction of the gas with Equation 17i.

### Equation 17i: Estimating Well Completion (Underbalanced Drilling) Emissions

$$E_i = Q \times (\text{lbmole}/379.3\text{scf}) \times MW_i \times f_i / 2204.62$$

where,

$E_i$  = emissions of the GHG (either CO<sub>2</sub> or CH<sub>4</sub>) from the completion (or drilling) of a single well, in tonne/well

$Q$  = total volume of gas vented during a well completion (or drilling), in scf/well

$MW_i$  = molecular weight of GHG, in lb/lbmole

$f_i$  = molar fraction of the GHG

2204.62 = conversion factor from lbs to tonnes

This methodology relies on an estimated volume of gas vented during the completion or underbalanced drilling operation. This volume is determined using engineering estimates based factors such as the dimensions of the well bore and downhole pressure and the duration of the completion venting. The Registry recommends that you keep comprehensive records of your completions and drilling activities.

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O&GP PR-10:

## DRILLING MUD DEGASSING AND WELL COMPLETION EMISSIONS ESTIMATION METHODOLOGY

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You can calculate CH<sub>4</sub> emissions from mud drilling degassing operations by using the emission factors contained in the table below and Equation 17j. Emissions from well completion operations should be calculated using this same equation and the emission factors contained in Table 17.5.

**Table 17.5 – Mud Degassing Emission Factors<sup>35</sup>**

Emission Source	Emission Factor Units <sup>a</sup>	Emission Factor Units <sup>b</sup>
Mud degassing – water-based mud	881.84 lbs THC / drilling day	0.2605 tonnes CH <sub>4</sub> / drilling day
Mud degassing – oil-based mud	198.41 lbs THC / drilling day	0.0586 tonnes CH <sub>4</sub> / drilling day
Mud degassing – synthetic mud	198.41 lbs THC / drilling day	0.0586 tonnes CH <sub>4</sub> / drilling day

Note: Assume synthetic mud has similar emission characteristics to oil-based mud. Apply the appropriate methane mass factor to the mud degassing emission factors.

Footnotes:

<sup>a</sup> Wilson, Darcy, Richard Billings, Regi Oommen, and Roger Chang, Eastern Research Group, Inc. *Year 2005 Gulfwide Emission Inventory Study*, U.S. Department of the Interior, Minerals Management Services, Gulf of Mexico OCS Region, New Orleans, December 2007, Section 5.2.10.

<sup>b</sup> Based on gas content of 65.13 weight percent CH<sub>4</sub>, derived from sample data provided in the original source of the emission factors. Original sample data is as follows, in terms of mole%: 83.85% CH<sub>4</sub>, 5.41% C<sub>2</sub>H<sub>6</sub>, 6.12% C<sub>3</sub>H<sub>8</sub>, 3.21% C<sub>4</sub>H<sub>10</sub>, and 1.40% C<sub>5</sub>H<sub>12</sub> (Wilson et al., 2007).

**Equation 17j: Estimating Drilling Mud Degassing Emissions**

$$E_{CH_4} = EF_i \times t_{annual}$$

where,

$E_{CH_4}$  = emissions of CH<sub>4</sub>, (tonne/yr)

$EF_i$  = emission factor of the source, (tonne/day)

$t_{annual}$  = number of drilling, (days/yr)

**17.3.1: Example: Calculation of Mud Degassing Vented Emissions<sup>36</sup>**

An O&GP production company performed well drilling activities with water-based mud 95 days during the year. The average CH<sub>4</sub> content of the gas is 75 mole percent; there is also 10 mole percent CO<sub>2</sub> in the gas.

$$E_{CH_4} = (0.2605 \text{ tonnes CH}_4/\text{day}) \times (75 \text{ mole \% CH}_4)/(83.85 \text{ mole \% CH}_4) \times 95 \text{ days/yr}$$

$$E_{CH_4} = 22.14 \text{ tonnes CH}_4/\text{yr}$$

<sup>35</sup> API 2009. "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry," Prepared for American Petroleum Institute (API), Prepared by URS Corp., August 2009. Section 5, Table 5-17. May 2009

<sup>36</sup> API 2009. "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry," Prepared for American Petroleum Institute (API), Prepared by URS Corp., August 2009. Section 5, Exhibit 5.23. 2009.

$$E_{\text{CO}_2} = (0.2605 \text{ tonnes CH}_4/\text{day}) \times (75 \text{ mole \% CH}_4)/(83.85 \text{ mole \% CH}_4) \times (\text{tonne mole CH}_4)/(16 \text{ tonnes CH}_4) \times (\text{tonne mole gas})/(0.75 \text{ tonnes mole CH}_4) \times (0.10 \text{ tonnes mole CO}_2)/(\text{tonne mole gas}) \times (44 \text{ tonnes CO}_2)/(\text{tonne mole CO}_2) \times 95 \text{ days/yr}$$

$$E_{\text{CO}_2} = 8.70 \text{ tonnes CO}_2/\text{yr}$$

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O&GP PR-11:

## WELL COMPLETION EMISSIONS FACTOR METHODOLOGY

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Table 17.6 below shows vented gas well completion CH<sub>4</sub> emission factors. Actual data on the volume of gas vented due to completion activities would provide a more rigorous emission estimate. You may use these emission factors when producing the wells to pits or tanks after the completion, in the absence of such data. The natural gas from the completion process can either be vented to the atmosphere or flared. If well completion gas is flared, you should calculate emissions using the flared methodologies from Chapter 12.

If green completion methods are used to recover any of the well completion emissions, you must multiply the uncontrolled (vented) CH<sub>4</sub> emission factor by the non-recovered fraction associated with the green completion method. The percent recovery via green completions should be based on site-specific data.

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### 17.4 Well Blowdowns

A well blowdown is performed to clean or unload a gas well in order to remove liquid buildup that reduces production rates. During a well blowdown, the well is opened to atmosphere so the downhole pressures may blow water from the tubing to an atmospheric storage tank. This process is used in shallow, low-pressure gas wells where downhole pressure may not be sufficient to overcome a liquid buildup.

The volume of gas released during a well blowdown depends on the duration of the event, wellhead temperature and pressure, size of the vent line, the properties of the gas and the quantity of water produced.

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O&GP PR-12:

## WELL BLOWDOWNS EMISSIONS ESTIMATION METHODOLOGY

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To estimate CH<sub>4</sub> and CO<sub>2</sub> emissions from well blowdowns, you should use the molar fraction of the gas and volume of the gas vented. Equation 17k describes the calculation method.

**Equation 17k: Calculating Emissions from Well Blowdowns**

$$E_{CH_4/CO_2} = (9.781 \times 10^{-7}) \times (1/z) \times (D_{casing})^2 \times (Depth) \times (P) \times (f_{CH_4/CO_2}) \times (MW_{CH_4/CO_2}) \times (Nb/year) \times (1/2204.62)$$

where,

$E_{CH_4/CO_2}$  = emissions of CO<sub>2</sub> or CH<sub>4</sub> (tonnes/year)

$z$  = compressibility factor<sup>37</sup>. Assumed to be 1 for an ideal gas

$D_{casing}$  = casing diameter (inches)

$Depth$  = well depth (feet)

$P$  = shut-in pressure (psig)

$f_{CH_4/CO_2}$  = molar fraction of CO<sub>2</sub> or CH<sub>4</sub>

$MW_{CH_4/CO_2}$  = molecular weight of CO<sub>2</sub> or CH<sub>4</sub> (lb/lbmole)

$Nb$  = number of blowdowns per year

2204.62 = conversion factor from lbs to tonnes

**17.4.1: Example: Calculation of Well Blowdowns Emissions**

A well blowdown is performed every two months (for a total of six per year). The casing diameter is eight inches, the well depth is 10,500 feet, and the shut-in pressure is 300 psig. The vented gas contains 75 mole percent CH<sub>4</sub> and 5 mole percent CO<sub>2</sub>. Calculate CH<sub>4</sub> and CO<sub>2</sub> emissions.

$$E_{CH_4} = (9.781 \times 10^{-7}) \times (1/1) \times (8)^2 \times (10,500) \times (300) \times (16) \times (0.75) \times (6) \times (1/2204.62)$$

$$E_{CH_4} = 6.44 \text{ tonnes CH}_4/\text{yr}$$

$$E_{CO_2} = (9.781 \times 10^{-7}) \times (1/1) \times (8)^2 \times (10,500) \times (300) \times (44) \times (0.05) \times (6) \times (1/2204.62)$$

$$E_{CO_2} = 1.18 \text{ tonnes CO}_2/\text{yr}$$

<sup>37</sup> Compressibility factor values for CH<sub>4</sub> and CO<sub>2</sub> can be found in a chemical engineering reference, such as "Perry's Chemical Engineer's Handbook." ISBN 978-0-07-049841-9

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## 17.5 Vessel and Facility Upsets/Blowdowns and Compressor Engine Start-Ups and Shutdowns

This section provides methods for calculating fugitive emissions of CH<sub>4</sub> and CO<sub>2</sub> from non-routine activities that release gasses from processing equipment, including vessels (separators), compressors, well tubing and oil pump stations. These types of activities can be categorized as either planned or unplanned. Planned activities refer to scheduled maintenance and turnaround activities, including vessel and gathering pipeline blowdowns, compressor starts and blowdowns, oil and gas well workovers, on and offshore gas well completions. Unplanned events refer to emergency or upset events that result in gas venting from equipment, such as pressure relief valve releases, gathering gas pipeline mishaps and emergency shutdowns. Many types of equipment must be purged of oxygen prior to re-pressurization, and this is often accomplished with natural gas, some of which may be vented to the atmosphere in the process. This section does not include emissions from CO<sub>2</sub> well stimulation, well unloading or well blowouts.

Emissions from these non-routine activities can be estimated in two ways:

1. An engineering approach considers the volume and composition of the gas released.
2. An emission factor approach estimates emissions on a per-unit or production basis.

Emission factors are tailored for the production and processing segments. You can also use the methods below to estimate volumes of gas that are sent to a flare during procedures which are not vented into the atmosphere. Where these gases are captured and sent to a flare, or other control device, you should calculate emissions using the methods in Chapter 12, Section 12.5.

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### O&GP PR-13:

#### METHOD FOR CALCULATING VENTED EMISSIONS NON-ROUTINE EVENTS USING ENGINEERING CALCULATIONS

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In order to calculate the quantity of the gas released, it is necessary to know the temperature, volume and pressure of that gas before it was released. The volume of the gas is determined by the dimensions of the equipment from which it was released, which can be measured or discerned from product specifications and/or design data. For more information on estimating the volumes of vessels and other equipment, refer to CAPP's *Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities*.<sup>38</sup> The pressure and temperature are dependent on the operating conditions prior to the release. Using this information, the quantity, in moles, of gas can be calculated using Equation 17I.

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<sup>38</sup> For more information: [www.capp.ca/raw.asp?x=1&dt=PDF&dn=38234](http://www.capp.ca/raw.asp?x=1&dt=PDF&dn=38234)

**Equation 17i: Calculating the Quantity of Gas Released From Non-Routine Activities**

$$n = PV/zRT$$

where:

$n$  = number of moles of gas

$P$  = pressure (atm or psi)

$V$  = volume (m<sup>3</sup> or scf)

$z$  = compressibility factor<sup>39</sup>

$R$  = gas constant (value depends on volume, temperature and pressure units used)

$T$  = absolute temperature (°R or K)

Once the number of moles of the gas is calculated, you can convert it to mass using Equation 17m.

**Equation 17m: Converting Moles of Gas to Mass of Gas Released from Non-routine Activities**

$$E_{CH_4/CO_2} = n/event \times mole \%_i \times MW_i \times events \times 2204.62$$

where:

$E_{CH_4/CO_2}$  = total emissions of CH<sub>4</sub> or CO<sub>2</sub> (tonne/yr)

$n/event$  = number of moles of gas released during each event

$mole \%_i$  = molar fraction of CH<sub>4</sub> or CO<sub>2</sub> in the gas released

$MW_i$  = molecular weight of CH<sub>4</sub> (16 lb/lb-mole) or CO<sub>2</sub> (44 lb/lb-mole)

$events$  = number of events per year

$2204.62$  = conversion factor from lbs to tonnes

If it is available, you should use CH<sub>4</sub> and CO<sub>2</sub> composition data specific to the gas stream used in the equipment. You should collect and analyze natural gas composition data according to applicable industry-approved, national, or international technical standards regarding sampling frequency, procedures, and preparation.

<sup>39</sup> Compressibility factor values for CH<sub>4</sub> and CO<sub>2</sub> can be found in a chemical engineering reference, such as "Perry's Chemical Engineer's Handbook." ISBN 978-0-07-049841-9.

For additional resources on gas composition analysis methods, refer to:

- ASTM D 2650: Standard Test Method for Chemical Composition of Gases by Mass Spectrometry
- ASTM D1945-03: Standard Test Method for Analysis of Natural Gas by Gas Chromatography
- ASTM D4984–06: Standard Test Method for Carbon Dioxide in Natural Gas Using Length-of-Stain Detector Tubes

If you do not have access to site-specific gas composition data, you can assume CH<sub>4</sub> content (molar percent) of 78.8 for natural gas in the production segment, and 86.8 in the processing segment.<sup>40</sup> Once you have calculated total CH<sub>4</sub> and CO<sub>2</sub> emissions, convert CH<sub>4</sub> emissions to tonnes of CO<sub>2</sub>-e, by multiplying the quantity of CH<sub>4</sub> calculated by its GWP (21). Sum all values to determine the total emissions from non-routine activities in tonnes CO<sub>2</sub>-e.

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#### 17.5.1: Example: Calculation of Well Blowdowns Emissions

A blowdown is performed in a low pressure separator operating at 100 psig and ambient temperature (~80 °F), to replace a gauge. The vessel dimensions are five ft in diameter and 12 ft long. The gas composition in the separator is 95 percent CH<sub>4</sub> with no CO<sub>2</sub>. The volume of gas released is 84 ft<sup>3</sup>. Calculate the CH<sub>4</sub> emissions.

$$n = (100 + 14.7) \times (84) / (0.9864) \times (10.73) \times (539) = 1.69 \text{ lbmoles gas/blowdown event}$$

$$E_{\text{CH}_4} = (1.69/1 \text{ blowdown}) \times (0.95) \times (16) \times (1 \text{ blowdown/year}) \times (1/2204.62)$$

$$E_{\text{CH}_4} = 0.016 \text{ tonnes CH}_4/\text{yr}$$

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#### O&GP PR-14:

### METHOD FOR CALCULATING FUGITIVE EMISSIONS NON-ROUTINE EVENTS USING EMISSION FACTORS

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This method uses emission rates for non-routine events for the production and processing segments. Equation 17p relies on emission factors for the event type, gas composition information and activity data to calculate fugitive emissions from non-routine activities.

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<sup>40</sup> API 2009. "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry," Prepared for American Petroleum Institute (API), Prepared by URS Corp., August 2009. Table E - 4. May 2009

This approach involves three steps:

1. Determine the emission factor for each non-routine event;
2. Calculate CH<sub>4</sub> and CO<sub>2</sub> emissions for each non-routine event; and
3. Convert CH<sub>4</sub> emissions to units of CO<sub>2</sub>-e and sum to determine total emissions.

## STEP 1: DETERMINE THE APPROPRIATE MASS EMISSION FACTOR FOR EACH NON-ROUTINE TYPE

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Table 17.6 lists CH<sub>4</sub> emission factors for different oil and gas production source types. Note that the emission factors are given on a unit production basis in some cases and on a production bases in others.

**Table 17.6 – Equipment Level CH<sub>4</sub> Emission Rates by Source Type<sup>41</sup>**

Source	CH <sub>4</sub> Emission Factor	Emission Factor Unit Basis	CH <sub>4</sub> Content (mole %)
<b>Production Segment Planned Activities</b>			
Vessel blowdowns	0.0015	tonnes/vessel-yr	78.8
Compressor starts	0.1620	tonnes/compressor-yr	78.8
Compressor blowdowns	0.07239	tonnes/compressor-yr	78.8
Gas well workovers (tubing maintenance)	0.04707	tonnes/workover	Not given
Oil well workovers (tubing maintenance)	0.0018	tonnes/workover	Not given
Gathering gas pipeline blowdowns	0.00593	tonnes/mile-yr	78.8
Onshore gas well completion	25.9	tonne/completion-day	78.8
Offshore gas well completion	131.5	tonne/completion-day	78.8
Oil pump stations (maintenance)	7.076E-04	tonnes/station-yr	Not given
<b>Production Segment Unplanned Activities</b>			
Pressure relief valves releases	0.00065	tonnes/PRV-yr	78.8
Gathering gas pipeline mishaps (dig-ins)	0.0128	tonnes/mile-yr	78.8
Offshore emergency shutdown (ESD)	4.9276	tonnes/platform-yr	78.8
<b>Processing Segment, All Non-Routine Activities</b>			
Gas Processing Non-Routine Activities	3.524E-03	tonnes/10 <sup>6</sup> scf processed	86.8

If you have site-specific information on the CH<sub>4</sub> content of the natural gas being processed, you can adjust the emission factors provided in Table 17.6 to reflect your own natural gas composition. This is done by multiplying the emission factors from Table 17.6 by the ratio of CH<sub>4</sub> content of your own gas to the default methane content values also provided in Table 17.6, as shown in Equation 17n. You should collect and analyze natural gas composition data according

<sup>41</sup> API 2009. "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry," Prepared for American Petroleum Institute (API), Prepared by URS Corp., August 2009, Tables 5-23 – 5-25.

to applicable industry-approved, national, or international technical standards regarding sampling frequency, procedures, and preparation.

For additional resources on gas composition analysis methods, refer to:

- ASTM D 2650: Standard Test Method for Chemical Composition of Gases by Mass Spectrometry
- ASTM D1945-03: Standard Test Method for Analysis of Natural Gas by Gas Chromatography
- ASTM D4984–06: Standard Test Method for Carbon Dioxide in Natural Gas Using Length-of-Stain Detector Tubes

**Equation 17n: Correcting Default CH<sub>4</sub> Emission Factors to Reflect Site-Specific CH<sub>4</sub> Content**

$$EF_{CH_4 site} = (EF_{CH_4 GD default}) \times (CH_4 site / CH_4 default)$$

where,

$EF_{CH_4 site}$  = Updated CH<sub>4</sub> emission factor, adjusted for site-specific CH<sub>4</sub> content of natural gas (tonnes/activity unit)

$EF_{CH_4 GD default}$  = Industry-specific CH<sub>4</sub> emission factor provided in Table 17.6 (tonnes/activity unit)

$CH_4 site$  = Site-specific CH<sub>4</sub> content provided by Member (molar %)

$CH_4 default$  = Segment-specific CH<sub>4</sub> content provided in Table 17.6 (molar %)

You can calculate an equivalent CO<sub>2</sub> emission factor from a CH<sub>4</sub> emission factor based on the relative concentrations of CO<sub>2</sub> and CH<sub>4</sub> in the natural gas stream in question. This conversion is shown in Equation 17o.

**Equation 17o: CH<sub>4</sub> to CO<sub>2</sub> Emission Factor Conversion**

$$EF_{CO_2} = EF_{CH_4} \times (44/16) \times (\text{mol } \% \text{ CO}_2 / \text{mol } \% \text{ CH}_4)$$

where,

$EF_{CO_2}$  = CO<sub>2</sub> emission factor

$EF_{CH_4}$  = CH<sub>4</sub> emission factor

44 = Molecular weight of CO<sub>2</sub> (g/mole)

16 = Molecular weight of CH<sub>4</sub> (g/mole)

mol % CO<sub>2</sub> = Concentration of CO<sub>2</sub> in the natural gas stream [molar %]

mol % CH<sub>4</sub> = Concentration of CH<sub>4</sub> in the natural gas stream [molar %]

**STEP 2: CALCULATE CH<sub>4</sub> AND CO<sub>2</sub> EMISSIONS FROM EACH EVENT**

Using the emission factor obtained in Step 1, calculate total CH<sub>4</sub> and CO<sub>2</sub> emissions from each event using Equation 17p below.

**Equation 17p: Calculating CO<sub>2</sub> and CH<sub>4</sub> Emissions from Non-Routine Activities**

$$E_{CH_4/CO_2} = ER_I \times t_{annuali}$$

where:

$E_{CH_4/CO_2}$  = the total fugitive emissions of CH<sub>4</sub> or CO<sub>2</sub> from non-routine events (tonnes/yr)

$ER_I$  = CH<sub>4</sub> or CO<sub>2</sub> emission factor from event type I (tonnes/activity unit)

$t_{annuali}$  = Annual event occurrences, or production data (activity unit)

**STEP3: CONVERT CH<sub>4</sub> EMISSIONS TO UNITS OF CO<sub>2</sub> EQUIVALENT.**

To convert CH<sub>4</sub> emissions to tonnes of CO<sub>2</sub>-e, multiply the quantity of CH<sub>4</sub> calculated in Step 2 by its GWP (21). Sum all values to determine the total emissions from facilities in tonnes CO<sub>2</sub>-e.

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## 17.6 Truck, Tanker, Rail Loading

The amount of hydrocarbon emissions from tank, truck, and rail loading activities is a relatively small portion of the total emissions for the O&GP sector. Nonetheless, where these activities occur they can be a significant local source of emissions. Emissions from these activities may be attributed to three major effects:

- Physical displacement of residual vapors by the incoming liquid,
- Evaporation effects promoted by agitation of the liquid during the transfer process, and
- Leakage/spillage during the connection of transfer lines and during the transfer process.

This section presents emission calculation approaches from loading activities during oil and gas production activities. The methodologies presented here show methods to estimate TOC emissions that require a vapor phase CH<sub>4</sub> or CO<sub>2</sub> (if present) content to convert to CH<sub>4</sub> or CO<sub>2</sub> emissions. When site-specific data is not available, assume a 15 wt percent vapor phase CH<sub>4</sub> content of live crude.<sup>42</sup>

Due to the fact that there is no discernable CH<sub>4</sub> or CO<sub>2</sub> in most petroleum products (including 'weathered' crude), calculating evaporative emissions associated with loading activities is only recommended for live crude oil<sup>43</sup> or if measured CH<sub>4</sub> or CO<sub>2</sub> content data are available for weathered crude oil.<sup>44</sup>

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O&GP PR-15:

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### EMISSION FACTOR CALCULATION APPROACH FOR LOADING ACTIVITIES

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Use Equation 17q and Table 17.7 to calculate CH<sub>4</sub> or CO<sub>2</sub> emissions. In this methodology, you should convert TOC emissions to CH<sub>4</sub> or CO<sub>2</sub> emissions (if present) based on the CH<sub>4</sub> or CO<sub>2</sub> content of the loading vapors.

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<sup>42</sup> API 2009. "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry," Prepared for American Petroleum Institute (API), Prepared by URS Corp., August 2009. Section 5.

<sup>43</sup> Live crude oil: a crude oil that possesses all chemical components including light ends in proper amounts as found in the subsurface formation.

<sup>44</sup> Weathered crude oil: crude petroleum that, owing to evaporation and other natural causes during storage and handling, has lost an appreciable quantity of its more volatile components.

**Equation 17q: Calculating CH<sub>4</sub> and CO<sub>2</sub> Emissions From Loading Operations**

$$E_i = L_V \times F_A \times WF_i$$

where,

$E_i$  = Emission rate of CH<sub>4</sub> or CO<sub>2</sub> from all components of a given type in the stream

$L_V$  = Crude oil loading volume

$F_A$  = Average emission factor for the component type A

$WF_i$  = Average weight fraction of TOC, CH<sub>4</sub> or CO<sub>2</sub>

**Table 17.7 –TOC Emission Factors for Loading Losses<sup>a</sup>**

Loading Type	Units		Crude Oil <sup>b,c</sup>
Rail / Truck Loading <sup>d</sup> Submerged Loading – Dedicated normal service	Original	lb TOC/10 <sup>3</sup> gal loaded	2
	Units	mg TOC/L loaded	240
	Converted Units <sup>e</sup>	tonne TOC/ 10 <sup>6</sup> gal loaded tonne TOC/10 <sup>3</sup> m <sup>3</sup> loaded	0.91 0.240
Rail / Truck Loading <sup>d</sup> Submerged Loading – Vapor balance service	Original	lb TOC/10 <sup>3</sup> gal loaded	3
	Units	mg TOC/L loaded	400
	Converted Units <sup>e</sup>	tonne TOC/ 10 <sup>6</sup> gal loaded tonne TOC/10 <sup>3</sup> m <sup>3</sup> loaded	1.51 0.400
Rail / Truck Loading <sup>d</sup> Splash Loading – Dedicated normal service	Original	lb TOC/10 <sup>3</sup> gal loaded	5
	Units	mg TOC/L loaded	580
	Converted Units <sup>e</sup>	tonne TOC/ 10 <sup>6</sup> gal loaded tonne TOC/10 <sup>3</sup> m <sup>3</sup> loaded	2.20 0.580
Rail / Truck Loading <sup>d</sup> Splash Loading – Vapor balance service	Original	lb TOC/10 <sup>3</sup> gal loaded	3
	Units	mg TOC/L loaded	400
	Converted Units <sup>e</sup>	tonne TOC/ 10 <sup>6</sup> gal loaded tonne TOC/10 <sup>3</sup> m <sup>3</sup> loaded	1.51 0.400
Marine Loading <sup>f</sup> – Ships/ocean barges	Original	lb TOC/10 <sup>3</sup> gal loaded	0.61
	Units	mg TOC/L loaded	73
	Converted Units <sup>e</sup>	tonne TOC/ 10 <sup>6</sup> gal loaded tonne TOC/10 <sup>3</sup> m <sup>3</sup> loaded	0.28 0.073
Marine Loading <sup>f</sup> – Barges	Original	lb TOC/10 <sup>3</sup> gal loaded	1.0
	Units	mg TOC/L loaded	120
	Converted Units <sup>e</sup>	tonne TOC/ 10 <sup>6</sup> gal loaded tonne TOC/10 <sup>3</sup> m <sup>3</sup> loaded	0.45 0.120

Sources:

<sup>a</sup> The factors shown are for total organic compounds. AP-42 reports that the VOC comprises approximately 85 percent of the TOC for crude oil. Thus, a simplifying assumption for the CH<sub>4</sub> content of the TOC is 15 percent in the absence of site-specific data, recognizing that this will likely overestimate emissions.

<sup>b</sup> EPA, AP-42, Section 5, Tables 5.2-5 and 5.2-6, 2008.

<sup>c</sup> The example crude oil has an RVP of 5 psia.

<sup>d</sup> The rail/truck loading emission factors were derived using Equation B-5 assuming a liquid temperature of 60°F.

<sup>e</sup> Converted from original emission factors provided in units of mg/L in AP-42. Thus, round-off errors may result in some small differences when converting from the emission factors provided in units of lb/10<sup>3</sup> gallons.

<sup>f</sup> Marine loading factors based on a loaded liquid temperature of 60°F.

The following example illustrates the use of loading emission factors for crude oil loading operations.

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### 17.6.1: Example: Crude Oil Loading Loss Emissions Calculation using the Emission Factor Approach

Best Trucking loads 45,000 bbl/yr of crude oil into a tank truck via submerged loading and dedicated normal service. The crude vapors contain 10 wt percent CH<sub>4</sub>, the crude oil loading loss emission factor from tank truck submerged loading, dedicated normal service is 0.91 tonnes TOC per million gallons loaded.

Best Trucking calculates its loading loss as follows:

$$E_{\text{CH}_4} = (0.91 \text{ tonnes TOC}/10^6 \text{ gal}) \times (42 \text{ gal}/\text{bbl}) \times (45,000 \text{ bbl}/\text{yr}) \times (10 \text{ tonnes CH}_4/100 \text{ tonnes TOC})$$

$$E_{\text{CH}_4} = 0.172 \text{ tonnes CH}_4/\text{yr}$$

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### O&GP PR-16:

#### EMISSIONS CALCULATION APPROACH FOR CRUDE OIL LOADED INTO MARINE VESSELS

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This calculation method requires you to input the true vapor pressure of the crude oil (P), the Reid Vapor Pressure (RVP) and the molecular weight of the vapors (M).<sup>45</sup> Table 17.8 presents the physical properties of crude oil based on the average temperature of a facility. This table is limited to crude oil with a RVP of five and TVP between 40°F and 100°F. You should use site-specific data, if available.

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<sup>45</sup> Physical properties sources can be found in the following publications: Perry's Chemical Engineering Handbook (Perry, 1984); CRC (CRC Press, 1984).

**Table 17.8 – Crude Oil Physical Properties**

Petroleum Liquid	Vapor Molecular Weight 60°F, (lb/lb mole)	Condensed Vapor Density 60°F, (lb/gal)	Liquid Density 60°F, (lb/gal)	True Vapor Pressure (psi)						
				40°F	50°F	60°F	70°F	80°F	90°F	100°F
Crude Oil RVP 5	50	4.5	7.1	1.8	2.3	2.8	3.4	4.0	4.8	5.7

Source: EPA, AP-42, Table 7.1-2, February 1996.

You should use Equations 17r and 17s to calculate emissions from loading crude oil into ships and ocean barges.

**Equation 17r: Total Loading Loss TOC Emission Factor<sup>46</sup>**

$$C_L = C_A + C_G$$

where,

$C_L$  = Total loading loss TOC emission factor, in lb/10<sup>3</sup> gallon of crude oil loaded

$C_A$  = Arrival emission factor, from vapors in the empty tank vessel before loading, in lb/10<sup>3</sup> gallon loaded (Table 17.9)

$C_G$  = Emission factor for emissions generated during loading, in lb/10<sup>3</sup> gallon (calculated using Equation 17s, presented below)

**Equation 17s: Emission Factor for Losses Generated during Loading Activities<sup>47</sup>**

$$C_G = 1.84 \times (0.44P - 0.42) \times (MG/T)$$

where,

$P$  = True vapor pressure of crude oil loaded, in psia

$M$  = Molecular weight of the vapors, in lb/lb-mole

$G$  = Vapor growth factor = 1.02, dimensionless

$T$  = Temperature of the vapors, °R (°R = °F + 459.7)

<sup>46</sup> U.S. EPA AP-42, Section 5.2, June 2008. Equation 2.

<sup>47</sup> U.S. EPA AP-42, Section 5.2, June 2008. Equation 3.

**Table 17.9 – Average Arrival TOC Emission Factor (C<sub>A</sub>)**

Ship/Ocean Barge Tank Condition	Previous Cargo <sup>b</sup>	Arrival Emission Factor, C <sub>A</sub>		
		Original Units	Converted Units	
		lb TOC/10 <sup>3</sup> gallon <sup>a</sup>	tonnes TOC/10 <sup>6</sup> gal	tonnes TOC/10 <sup>6</sup> m <sup>3</sup>
Uncleaned	Volatile	0.86	0.39	103
Ballasted	Volatile	0.46	0.21	55
Cleaned or gas-freed	Volatile	0.33	0.15	40
Any condition	Non-volatile	0.33	0.15	40

<sup>a</sup> The factors shown are for total organic compounds.

<sup>b</sup> "Volatile" cargo refers to those cargoes with a vapor pressure greater than 1.5 psia.

Source: U.S. EPA, AP-42, Table 5.2-3, June 2008.

### 17.6.2: Example: Crude Oil Loading Loss Emissions Calculation from Loading into Marine Vessels

Excellent Shipping loads 45,000 bbl/day of crude oil (RVP 5) into ships. The ships are clean prior to loading. The average ambient temperature of the facility is 60°F based on annual meteorological data. The crude vapors contain eight wt percent CH<sub>4</sub>. The molecular weight of the crude oil is 50lb/lbmole and the true vapor pressure is 2.8 psi.

Excellent Shipping calculates CH<sub>4</sub> emissions as follows:

$$C_G = 1.84 \times [(0.44 \times 2.8) - 0.42] \times [(50 \times 1.02)/519.7]$$

$$C_G = 0.15 \text{ lbTOC}/10^3 \text{ gal}$$

The average arrival TOC emission factor for clean marine vessels is 0.33 lbTOC/10<sup>3</sup> gal  
The total loading loss factor is:

$$C_L = 0.33 + 0.15 = 0.48 \text{ lbTOC}/10^3 \text{ gal}$$

$$E_{CH_4} = (0.48 \text{ lbTOC}/10^3 \text{ gal}) \times (42 \text{ gal}/\text{bbl}) \times (45,000 \text{ bbl}/\text{yr}) \times (8 \text{ lbCH}_4/100 \text{ lbTOC}) \times (\text{tonne}/2204.62 \text{ lb})$$

$$E_{CH_4} = 0.033 \text{ tonnesCH}_4/\text{yr}$$

EMISSIONS CALCULATION APPROACH FOR CRUDE OIL LOADED INTO TANK TRUCKS AND RAIL CARS

Use Equation 17t to calculate emissions from loading crude oil into tank trucks and rail cars.

Equation 17t: Emission Factor for Losses Generated during Tank Truck and Rail Car Loading Activities <sup>48</sup>
$L_L = 12.46 \times [(S \times P \times M) / T] \times [1 - (C_E / 100)]$
<p>where,</p> <p><math>L_L</math> = loading loss emission factor, in lb/10<sup>3</sup> gallon of liquid loaded. This factor is for total organic compounds (TOC)</p> <p><math>S</math> = Saturation factor (see Table 17.10 below)</p> <p><math>P</math> = Liquid true vapor pressure, in psia</p> <p><math>M</math> = Molecular weight of the vapors, in lb/lb-mole</p> <p><math>T</math> = Temperature of bulk liquid loaded, °R (°R = °F + 459.7)</p> <p><math>C_E</math> = Control efficiency<sup>49</sup> (%)</p>

**Table 17.10 – Saturation, S, Factors for Estimating Loading Losses**

Cargo Carrier Type	Mode of Operation	S Factor
Tank trucks and rail tank cars	Submerged loading of a clean cargo tank	0.50
	Submerged loading, dedicated normal service	0.60
	Submerged loading, dedicated vapor balance service	1.00
	Splash loading of a clean cargo tank	1.45
	Splash loading, dedicated normal service	1.45
	Splash loading, dedicated vapor balance service	1.00

Source: U.S. EPA AP-42, Table 5.2-1, June 2008.

<sup>48</sup> U.S. EPA AP-42, Section 5.2, June 2008. Equation 1.

<sup>49</sup> The control efficiency term is included in the loading loss emission factor equation because some loading operations are controlled using various collection systems, such as Vapor Recovery Units (VRU). If applicable, the overall estimated control efficiency for the particular control system should be used.

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### 17.6.3: Example: Crude Oil Loading Loss Emissions Calculation using General Equation Approach

Best Trucking loads 500 bbl/day of crude oil (RVP 5) into a tank truck via a submerged loading and dedicated normal service. The saturation factor of the tank truck is 0.60. No control devices are used to minimize emissions. The average ambient temperature of the facility is 50°F. The molecular weight of the crude oil is 50lb/lbmole and the true vapor pressure is 2.3 psi. The crude vapors contain 5 wt percent CH<sub>4</sub>.

$$L_L = 12.46 \times [(0.6) \times (2.3) \times (50)] / 509.7 \times (1 - 0\%/100)$$

$$L_L = 1.69 \text{ lbTOC}/10^3 \text{ gal}$$

$$E_{\text{CH}_4} = (1.69 \text{ tonnesTOC}/10^3 \text{ gal}) \times (42 \text{ gal}/\text{bbl}) \times (182,500 \text{ bbl}/\text{yr}) \times (5 \text{ lbCH}_4/100 \text{ lbTOC}) \\ \times (\text{tonne}/2204.62 \text{ lb})$$

$$E_{\text{CH}_4} = 0.294 \text{ tonnesCH}_4/\text{yr}$$

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## 17.7 Ballasting and Transit Loss Emissions

Ballasting operations are used to improve the stability of empty tanker ships after their cargo tanks have been unloaded. After ships filled with petroleum liquid are unloaded at marine terminals, sea water or ballast water is loaded into the empty cargo tank compartment. The ballast water displaces the vapor in the empty cargo tank to the atmosphere resulting in ballasting emissions.

GHG emissions can occur during petroleum transit. The conditions that affect transit emissions are the vapor tightness of the cargo vessel, the cargo vessel pressure at the beginning of the trip, the pressure relief valve settings, the liquid vapor pressure, and the degree of vapor saturation in the vapor void space of the cargo tank.

This section contains directions for calculating GHG emissions from ballasting and transit loss activities.

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### O&GP PR-18:

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#### BALLASTING EMISSIONS ESTIMATION METHODOLOGY

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Use Equation 17u and Table 17.11 to calculate emissions from ballasting operations. Table 17.11 provides average emission factors for estimating TOC emissions from crude ballasting operations.

**Equation 17u: Calculating CH<sub>4</sub> and CO<sub>2</sub> Emissions From Ballasting**

$$E_i = AF \times EF$$

where,

$E_i$  = Total CH<sub>4</sub> or CO<sub>2</sub> emissions

$AF$  = Activity factor (i.e. annual ballast water throughput)

$EF$  = Emission factor

**Table 17.11 – Average TOC Emission Factors for Crude Oil Ballasting Operations**

Compartment Condition Before Cargo Discharge	Average TOC Emission Factors, <sup>a,b</sup> Original Units		Average TOC Emission Factors, <sup>c</sup> Converted to Tonnes	
	lb TOC/10 <sup>3</sup> gal ballast water	mg TOC/L ballast water	tonne TOC/10 <sup>6</sup> gal ballast water	tonne TOC/10 <sup>3</sup> m <sup>3</sup> ballast water
Fully loaded <sup>d</sup>	0.9	111	0.420	0.111
Lightered or previously short loaded <sup>e</sup>	1.4	171	0.647	0.171
Typical overall situation <sup>f</sup>	1.1	129	0.488	0.129

Sources:

<sup>a</sup> EPA, AP-42, Section 5, Table 5.2-4, 2008.

<sup>b</sup> The factors shown are for total organic compounds. The average factors were derived assuming an average crude temperature of 60°F and a crude RVP of 5 psi. AP-42 reports that the VOC comprises an approximate average of 85% of the TOC for crude. Thus, a simplifying assumption for the CH<sub>4</sub> content of the TOC is 15% in the absence of site-specific data, recognizing that this will likely overestimate emissions.

<sup>c</sup> Converted from original emission factors provided in units of mg/L in AP-42. Thus, round-off errors may result in some small differences when converting from the emission factors provided in units of lb/10<sup>3</sup> gallons.

<sup>d</sup> Based on assumed typical arrival ullage of 0.6 m (2 feet).

<sup>e</sup> Based on assumed typical arrival ullage of 6.1 m (20 feet).

<sup>f</sup> Typical overall situation based on the observation that 70% of tested compartments had been fully loaded before ballasting.

The factors are categorized according to how full the cargo tank is prior to discharge. The fully loaded cargo category applies to those compartments that have a true ullage<sup>50</sup> of less than five feet prior to crude discharge. The lightered or previously short loaded category applies to those cargoes that have an arrival ullage of more than five feet.

<sup>50</sup> Ullage refers to the distance between the cargo surface level and the deck level.

## TRANSIT LOSS EMISSIONS ESTIMATION METHODOLOGY

You should use Equation 17-21 from the previous section and Table 17.12 to calculate emissions from transit loss. Table 17.12 provides simple transit TOC emission factors for marine transit of crude oil

**Table 17.12 – Simplified TOC Emission Factors for Marine Transit Losses<sup>a</sup>**

	Units	Crude Oil <sup>b,c</sup>
Original Units	lb TOC/week-10 <sup>3</sup> gal transported	1.3
	mg TOC/week-L transported	150
Converted Units <sup>d</sup>	tonne TOC/week-10 <sup>6</sup> gal transported	0.57
	tonne TOC/week-10 <sup>3</sup> m <sup>3</sup> transported	0.150

Sources:

<sup>a</sup> The factors shown are for TOCs. AP-42 reports that the VOC comprises approximately 85% of the TOC for crude. Thus, a simplifying assumption for the CH<sub>4</sub> content of the TOC is 15% in the absence of site-specific data, recognizing that this will likely overestimate emissions.

<sup>b</sup> EPA, AP-42, Section 5, Table 5.2-6, 2008.

<sup>c</sup> The example crude oil has an RVP of 5 psia.

<sup>d</sup> Converted from original emission factors provided in units of mg/L in AP-42. Thus, round-off errors may result in some small differences when converting from the emission factors provided in units of lb/10<sup>3</sup> gallons.

## 17.8 Pipeline Blowdowns and Pigging

Pipeline blowdowns can occur during repair work when gas is used for displacement or testing purposes or when lines are put out of service. Pipeline pigging operations occur at oil pipelines during product transfer, product separation, and maintenance. In cases where there is live crude oil, Members should refer to the appropriate section of Chapter 16, Section 16.1 to calculate emissions from pigging operations.

This section presents emission calculation methods to estimate vented emissions from pipeline blowdowns.

## PIPELINE BLOWDOWNS EMISSIONS ESTIMATION METHODOLOGY

This methodology relies on an estimated volume of gas vented during pipeline blowdowns. This volume is determined using engineering estimates based factors such as the dimensions of the pipeline and operating pressure and temperature. The Registry encourages Members to keep comprehensive records of their pipeline blowdowns activities.

**Equation 17v: Estimating Pipeline Blowdowns and Pigging Activities Emissions**

$$E_i = Q \times (\text{lbmole}/379.3\text{scf}) \times MW_i \times f_i / 2204.62$$

where,

$E_i$  = emissions of the GHG (either CO<sub>2</sub> or CH<sub>4</sub>) (tonne/yr)

$Q$  = total volume of gas vented (scf/yr)

$MW_i$  = molecular weight of GHG (lb/lbmole)

$f_i$  = molar fraction of the GHG

2204.62 = conversion factor from lbs to tonnes

In order to determine the volume of gas associated with pipeline operations, you should estimate the volume of gas vented at the process temperature and pressure and convert the calculated volume to standard conditions (15°C and 101.325 kPa).

Equation 17w presents a method to calculate volume.

**Equation 17w: Calculating Volume of Gas Released**

$$Q_T = Q_A \times (T_s / P_s) \times [(P_i / z_i T_i) - (P_f / z_f T_f)]$$

where,

$Q_T$  = total volume of gas released at standard conditions at 15°C and 101.325 kPa (m<sup>3</sup>)

$Q_A$  = actual volume at process conditions

$T_s$  = initial process temperature (K)

$P_s$  = standard pressure (kPa)

$P$  = process pressure (kPa)

$z$  = compressibility factor for the gas

$T$  = process temperature (K)

$i$  = initial pressure and temperature

$f$  = final pressure and temperature

**Equation 17x: Calculating Actual Volume ( $Q_A$ )**

$$Q_A = L_P \times F$$

where,

$Q_A$  = actual volume at process conditions

$L_P$  = pipeline length, in m

$F$  = volume factor (see Table 17-13)

**Table 17.13 – Volume Occupied by a One-Meter Length of Various Standard Pipe Sizes<sup>a</sup>**

NPS Size	Sch 40 m <sup>3</sup> /m	Sch 60 m <sup>3</sup> /m	Sch 80 m <sup>3</sup> /m	Sch 100 m <sup>3</sup> /m	Sch 120 m <sup>3</sup> /m	Sch 140 m <sup>3</sup> /m	Sch 160 m <sup>3</sup> /m
1	5.574E-4		4.639E-4				3.366E-4
2	2.165E-3		1.905E-3				1.446E-3
3	4.770E-3		4.261E-3				3.489E-3
4	8.213E-3		7.419E-3		6.652E-3		5.987E-3
6	1.864E-2		1.682E-2		1.534E-2		1.365E-2
8	3.228E-2	3.093E-2	2.946E-2	2.804E-2	2.619E-2	2.484E-2	2.352E-2
10	5.088E-2	4.817E-2	4.635E-2	4.395E-2	4.163E-2	3.879E-2	3.661E-2
12	7.221E-2	6.849E-2	6.557E-2	6.203E-2	5.855E-2	5.586E-2	5.195E-2
14	8.728E-2	8.320E-2	7.917E-2	7.451E-2	7.072E-2	6.701E-2	6.343E-2
16	1.140E-1	1.093E-1	1.038E-1	9.844E-2	9.323E-2	8.728E-2	8.320E-2
18	1.443E-1	1.380E-1	1.318E-1	1.247E-1	1.178E-1	1.121E-1	1.056E-1
20	1.794E-1	1.711E-1	1.630E-1	1.541E-1	1.464E-1	1.379E-1	1.308E-1

Sources:

<sup>a</sup> Canadian Association of Petroleum Producers (CAPP). *Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities*, Guide. May 2002.

If you don't know the compressibility factor, you should estimate it using the equation below.

Equation 17y: Estimating Compressibility Factor <sup>51</sup>
$z = a + bP + cT + dP^2 + eT^2 + fPT$
<p>where,</p> <p><math>P</math> = initial process pressure, in kPa</p> <p><math>T</math> = initial process temperature, in °C</p>

**Table 17.14 – Correlation Coefficients for Estimating Compressibility Factors<sup>a</sup>**

Correlation Coefficient	Value
a	9.9187E-01
b	-3.3501E-05
c	6.9652E-04
d	6.3134E-10
e	-8.6023E-06
f	2.3290E-07

Sources:

<sup>a</sup> Canadian Association of Petroleum Producers (CAPP). *Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities*, Guide. May 2002.

## 17.9 Flashing Losses from Tanks

Crude oil production tanks emit CH<sub>4</sub> (and potentially CO<sub>2</sub> for a CO<sub>2</sub> rich stream) through flashing losses, which occur as the crude oil pressure decreases from the separator conditions to atmospheric pressure in the storage tank. Flashing emissions can be significant where there is a significant reduction in pressure. This primarily occurs during production operations.<sup>52</sup>

Tanks can be used extensively across oil fields, or their usage may be very minimal if there is significant pipeline infrastructure installed and the crude oil produced is sent to refinery facilities through pipelines. You should use the calculation methods below to estimate flashing losses from production storage tanks.

### O&GP PR-21:

#### DIRECT MEASUREMENTS METHODOLOGY

Tank fugitive emissions can be measured directly, providing accurate emissions estimates for the measured tanks.

You can measure GHG emissions from tanks using a flow meter (i.e. high volume samplers, calibrated bags, rotameters, turbine meters, etc) for a test period that represents normal operation conditions throughout the year. You should maintain records of: gross input of the storage tank during the test period, and temperature and pressure of hydrocarbon vapors emitted during the test period. Samples of hydrocarbon vapors should be collected for composition analysis.

You should calculate emissions from tanks as follows:

1. Calculate the total annual hydrocarbon vapor fugitive emissions using Equation 17z.

#### Equation 17z: Calculating Annual Hydrocarbon Vapor Fugitive Emissions

$$E_{a,h} = Q \times ER$$

where,

$E_{a,h}$  = Hydrocarbon vapor fugitive emissions at actual conditions

$Q$  = Storage tank annual throughput

$ER$  = Measured hydrocarbon vapor emissions rate per throughput (i.e. cubic feet/barrel) determined from direct measurement device.

<sup>52</sup> Liquid petroleum storage tanks can also produce emissions through working and breathing losses; these methodologies are described in Section 16.2.

2. Calculate the hydrocarbon vapor volumetric fugitive emissions in Equation 17-26 by using the Equation 17aa.

**Equation 17aa: Calculating Hydrocarbon Vapor Volumetric Fugitive Emissions**

$$E_{s,n} = [E_{a,n} \times (460 + T_s) \times P_a] / [(460 + T_a) \times P_s]$$

where,

$E_{s,n}$  = Natural gas volumetric fugitive emissions at standard temperature and pressure conditions (m<sup>3</sup>)

$E_{a,n}$  = Natural gas volumetric fugitive emissions at actual conditions (m<sup>3</sup>)

$T_s$  = Temperature at standard conditions (°F)

$P_a$  = Absolute pressure at ambient conditions (inches of Hg)

$T_a$  = Temperature at actual emission conditions (°F)

$P_s$  = Absolute pressure at standard conditions (inches of Hg)

3. Calculate CH<sub>4</sub> and CO<sub>2</sub> mass emissions from GHG volumetric fugitive emissions using Equation 17bb.

**Equation 17bb: Calculating CH<sub>4</sub> and CO<sub>2</sub> Emissions From Volumetric Fugitive Emissions**

$$Mass_{s,i} = E_{s,i} \times \rho_i$$

where,

$Mass_{s,i}$  = GHG<sub>i</sub> (either CH<sub>4</sub> and CO<sub>2</sub>) mass emissions at standard conditions (kg)

$E_{s,i}$  = GHG<sub>i</sub> (either CH<sub>4</sub> and CO<sub>2</sub>) volumetric emissions at standard conditions (m<sup>3</sup>)

$\rho_i$  = Density of GHG<sub>i</sub>; 1.87 kg/m<sup>3</sup> for CO<sub>2</sub> and 0.68 kg/m<sup>3</sup> for CH<sub>4</sub>.

O&GP PR-22:

**COMPUTER MODELING METHODOLOGY**

You may use API's E&P TANKS software (API, 1997) to estimate flashing losses. This program is based on Peng-Robinson (PR) Equation of State (EOS), which is a mathematical equation,

which represents the relationship between thermodynamic variables such as pressure, temperature, and volume of a specific material in thermodynamic equilibrium. You should use Equation 17cc to calculate CH<sub>4</sub> and CO<sub>2</sub> from volumetric fugitive emissions.

**Equation 17cc: Calculating CH<sub>4</sub> and CO<sub>2</sub> Emissions From Volumetric Fugitive Emissions**

$$p = (RT)/(V_m - b) - (a\alpha)/(V_m^2 + 2bV_m - b^2)$$

where,

$$a = (0.45724 R^2 T_c^2)/p_c$$

$$b = (0.07780 R T_c)/p_c$$

$$\alpha = (1 + (0.37464 + 1.54226 \omega - 0.26992 \omega^2)(1 - T_r^{0.5}))^2$$

$$T_r = T/T_c$$

This approach requires the following input parameters: tank configuration, API gravity and Reid Vapor Pressure (RVP) of the sales oil, separator pressurized oil composition, separator pressure and temperature, and production rate of liquid to tanks.

If the oil composition is unknown, the program contains a fluid composition database of more than one hundred oil analyses. You can sort the database by geographic region, sales oil physical properties, and separator pressure and temperature. You should select parameters that are as similar to the conditions of the particular oil and gas production installation as possible. The E&P TANKS model is valid for liquids with API gravity ranging from 16 to 68 degrees.

Once you have entered the appropriate data, you can calculate flashing losses that result from flashing the upstream oil stream to atmospheric pressure. You can infer normal evaporation losses by matching the oil properties obtained from the flash calculations to the specified API gravity and RVP of the sales oil.

O&GP PR-23:

PROCESS SIMULATORS METHODOLOGY

You may estimate flashing losses using professional process simulators, which are computer models that use EOS and mass and energy balance equations to simulate a variety of processes. There are a variety of process simulators that you can use to calculate flashing losses (HYSYS, HYSIM, PROSIM, etc).

Required input data for these systems includes: an extended pressurized condensate or oil analysis; temperature, pressure and flow rates for the process being simulated, etc. These simulators are not constrained by API gravity. The use of the process simulation method needs

to be done for each producing field/formation to develop the pressure-based regressions. Regressions from one field or formation cannot be used another unless the compositions are very similar.

The use of a simulation model involves the following steps:

- Selection of components
- Selection of a thermodynamics property package
- Construction of a flow sheet
- Specification of known streams, unit compositions and conditions
- Running the simulation program
- Analysis of the results

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O&GP PR-24:

## CORRELATION EQUATIONS METHODOLOGY

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You may use the Vasquez-Beggs Equation (VBE), standing correlation, or the Alberta Energy Utility Board (EUB) rule-of-thumb methods to estimate tank flashing losses when limited input data are available. The decision to use VBE or standing correlation versus EUB will depend on the data available. The EUB approach requires less data input. If sufficient data is available to use VBE or standing correlation, you may choose which method you prefer to use.

### A - VASQUEZ-BEGGS EQUATION (VBE)

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The Vasquez-Beggs Equation (VBE) estimates the gas to oil ratio (GOR) of a hydrocarbon as a function of the separator pressure, temperature, gas specific gravity, and the API gravity of the oil. Flashing losses are then calculated by multiplying the GOR by the tank throughput, the weight fraction of VOC in the gas, and the stock tank gas molecular weight. This method was designed for gases dissolved in crude oils, and is most appropriate for use in upstream operations.

This equation requires eight input parameters: API gravity, separator pressure, separator temperature, gas specific gravity, volume of produced oil, molecular weight of the stock tank gas, VOC fraction of tank emissions, and atmospheric pressure. This equation should not be used for oil with an API gravity greater than 45.

The first step in calculating flashing emissions is to estimate the specific gravity of the gas at 100 psig using Equation 17dd.

**Equation 17dd: Specific Gravity of Gas**

$$SG_X = SG_i \times \{1.0 + 0.00005912 \times API \times T_i \times \log [(P_i + 14.7)/114.7]\}$$

where,

$SG_X$  = Dissolved gas gravity, adjusted to 100psig

$SG_i$  = Dissolved gas gravity at initial conditions, where air = 1. A suggested default value for  $SG_i$  is 0.90 (OK DEQ, 2004)<sup>53</sup>

$API$  = API gravity of liquid hydrocarbon at final condition

$P_i$  = Pressure of initial conditions (psig)

$T_i$  = Temperature of initial conditions (°F)

Then, you should calculate the flash GOR using Equation 17-31:

**Equation 17ee: Flash GOR**

$$GOR = A \times SG_X \times (P_i + 14.7)^B \times \exp [(C \times G_{oil}) / (T_i + 460)]$$

where,

$GOR$  = Ratio of flash gas production to standard stock tank barrels of oil produced, in scf/bbl oil (barrels of oil corrected to 60°F)

$SG_X$  = Dissolved gas gravity, adjusted to 100 psig

$G_{oil}$  = API gravity of stock tank oil at 60°F

$P_i$  = Pressure in separator (psig)

$T_i$  = Temperature in separator (°F)

For  $G_{oil} \leq 30^\circ API$ :  $A = 0.0362$ ;  $B = 1.0937$ ; and  $C = 25.724$

For  $G_{oil} > 30^\circ API$ :  $A = 0.0178$ ;  $B = 1.187$ ; and  $C = 23.931$

<sup>53</sup> <http://www.deq.state.ok.us/factsheets/air/CalculationLosses.pdf>

The flash gas emissions estimated by the VBE are in terms of total hydrocarbon. Thus, the last step is to estimate the CH<sub>4</sub> content in the tank flash gas vent. In the absence of site-specific data, the recommended tank vent CH<sub>4</sub> content is 27.4 volume percent.<sup>54</sup> A sample calculation illustrating the use of the VBE applied to flashing loss emissions is provided below.

### 17.9.1: Example: Flashing Loss Emissions Calculation using the Vasquez-Beggs Equation (VBE)<sup>55</sup>

An O&GP Installation produces 71.70 m<sup>3</sup>/day (451 bbl/day) of crude oil with an API gravity of 48.8°. The separator pressure (immediately upstream of the tank) is 197.2 kPa gauge (28.6 psig) and the separator temperature is 44.4°C (112°F). Neither the tank vent CH<sub>4</sub> content nor the tank vent gas specific gravity is known. Flashing losses are not controlled by a vapor recovery system.

You must calculate the flash gas specific gravity adjusted to 100 psig. The flash gas specific gravity at initial conditions, SG<sub>i</sub>, is not known, so the recommended default value of 0.90 will be used.

$$SG_x = 0.90 \times \{1.0 + 0.00005912 \times 48.8 \times 112 \times \log [(28.6 + 14.7)/114.7]\}$$

$$SG_x = 0.78$$

You should use Equation 17ee to calculate the flash gas vent flow rate (GOR), using the A, B, and C parameters for an API gravity less than 30.

$$GOR = 0.0178 \times (0.78) \times (28.6 + 14.7)^{1.187} \times \exp [(23.931 \times 48.8)/(112 + 460)]$$

$$GOR = 9.33 \text{ scf/bbl oil}$$

The output from this equation is in units of scf/bbl oil.

$$GOR = (9.33 \text{ scf gas/bbl crude}) \times (\text{m}^3 \text{ gas} / 35.3147 \text{ scf gas}) \times (\text{bbl crude} / 0.1589873 \text{ m}^3 \text{ crude})$$

$$GOR = 1.66 \text{ m}^3 \text{ gas} / \text{m}^3 \text{ crude}$$

The flash gas contains gases besides CH<sub>4</sub> and thus you must multiply the GOR by the tank vent CH<sub>4</sub> content. The tank vent CH<sub>4</sub> content is not known, so you should use the recommended

<sup>54</sup> This value is the average tank vent gas composition from two published studies that measured flashing loss emissions from tanks (Ogle, March 1997/ Ogle, May 1997; Picard, Vol. III, 1992).

<sup>55</sup> API 2009. "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry," Prepared for American Petroleum Institute (API), Prepared by URS Corp., August 2009. Section 5 - Process and Vented Emission Estimation Methods.

default concentration of 27.4 volume percent CH<sub>4</sub>. You should calculate the CH<sub>4</sub> emissions as follows:

$$E (\text{CH}_4) = (1.66 \text{ m}^3 \text{ gas/m}^3 \text{ oil}) \times (71.70 \text{ m}^3 \text{ oil/day}) \times (365 \text{ day/yr}) \times (\text{kgmole gas}/23.685 \text{ m}^3) \times (27.4 \text{ kgmole CH}_4/100 \text{ kgmole gas}) \times (16 \text{ kg CH}_4/\text{kgmole CH}_4) \times (\text{tonne}/1000 \text{ kg})$$

$$E (\text{CH}_4) = 8.04 \text{ tonnes CH}_4/\text{yr}$$

As a validation of this example, a spreadsheet from the Oklahoma DEQ<sup>56</sup> can be used. While this spreadsheet does not provide CH<sub>4</sub> emissions, it does calculate the flash gas to oil ratio that is the basis for the CH<sub>4</sub> emissions estimate.

## B - STANDING CORRELATION

As in the case of VBE, this correlation is based on the regression of experimentally determined bubble point pressures for variety of crude oil systems. This equation requires the following input parameters: API gravity, separator absolute pressure, separator temperature, gas specific gravity, and water specific gravity.

### Equation 17ff: Standing Correlation

$$GOR = G_{flash \text{ gas}} \times (P/519.7 \times 10^{Y_g})^{1.204}$$

where,

$GOR$  = Ratio of flash gas production to oil produced,  $\text{m}^3/\text{m}^3 \text{ oil}$

$G_{flash \text{ gas}}$  = Specific gravity of the tank flash gas, where air = 1. A suggested

default value for  $G_{flash \text{ gas}}$  is 0.90 (OK DEQ, 2004)<sup>57</sup>

$P$  = Absolute pressure in vessel, kPa

$$Y_g = 1.225 + 0.00164 \times T - (1.769/SG_{oil})$$

$SG_{oil}$  = specific gravity of oil with respect to water =  $141.5/(131.5 + G_{oil})$

$G_{oil}$  = API gravity of stock tank oil at 60°F

<sup>56</sup> <http://www.deq.state.ok.us/AQDnew/resources/Calculations11.xls>

<sup>57</sup> <http://www.deq.state.ok.us/factsheets/air/CalculationLosses.pdf>

Where the crude flash occurs from a separator to an atmospheric tank, you must separately evaluate the term in parenthesis for the separator and the oil storage tank. In these cases you should use Equation 17gg.

**Equation 17gg: Standing Correlation – Crude Flash Occurring from Separator<sup>58</sup>**

$$GOR = G_{flash\ gas} \times [ \{ (P / 519.7 \times 10^{y_g})^{1.204} \}_{Separator} - \{ (P / 519.7 \times 10^{y_g})^{1.204} \}_{Tank} ]$$

As in the case of the VBE approach, the CH<sub>4</sub> content must be estimated using the recommended tank vent CH<sub>4</sub> content is 27.4 volume percent.<sup>59</sup>

**17.9.2: Example: Flashing Loss Emissions Calculation using Standing Correlation<sup>60</sup>**

The O&GP Installation is the same oil and gas production facility described in the previous Example 17.9.1. Crude oil production per day is 451 bbl (71.7 m<sup>3</sup> oil/day), API gravity is 48.8°, and flashing losses occur as the oil flows from a separator at 28.6 psig and 112°F to an atmospheric tank. The atmospheric temperature (and thus the storage tank temperature) is assumed to be 80°F (299.8 K). Flashing losses are not controlled by a vapor recovery system. The Member has to calculate flashing loss emissions using Equation 17gg.

First, you must convert the input parameters to the proper SI units for use in the equation. Note that the separator absolute pressure is 43.3 psia (28.6 psig + 14.7 psia) while the tank pressure is one atm. Thus, the pressures in kPa are:

$$P_{sep} = (43.3 \text{ psi}) \times (6.894757 \text{ kPa/psi}) = 298.5 \text{ kPa}$$

$$P_{tank} = (1 \text{ atm}) \times (101.325 \text{ kPa/atm}) = 101.3 \text{ kPa}$$

Next, you must convert the oil API gravity (Goil) into a specific gravity:

$$SG_{oil} = 141.5 / (131.5 + Goil) = 141.5 / (131.5 + 48.8) = 0.785$$

Next, you should calculate the parameter y<sub>g</sub> for both the separator and tank using the oil-specific gravity and temperatures in the separator (112°F or 317.6 K) and the tank (80°F or 299.8 K):

$$y_{g,sep} = 1.225 + (0.00164) \times (317.6) - (1.769 / 0.785) = -0.5076$$

<sup>58</sup> Note that the units for the standing correlation variables are different than the units for the VBE.

<sup>59</sup> Average tank vent gas composition from Ogle, March 1997/ Ogle, May 1997; Picard, Vol. III, 1992.

<sup>60</sup> API 2009. "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry," Prepared for American Petroleum Institute (API), Prepared by URS Corp., August 2009. Section 5 - Process and Vented Emission Estimation Methods.

$$y_{g,tank} = 1.225 + (0.00164) \times (299.8) - (1.769/0.785) = -0.5368$$

The flash gas vent flow rate (GOR) is calculated below:

$$GOR = 0.90 \times \left[ \left\{ \left( \frac{298.5}{519.7 \times 10^{-0.5076}} \right)^{1.204} \right\} \text{Sep} - \left\{ \left( \frac{101.3}{519.7 \times 10^{-0.5368}} \right)^{1.204} \right\} \text{Tank} \right]$$

$$GOR = 1.329 \text{ m}^3 \text{ gas/m}^3 \text{ oil}$$

Similar to Example 17.9.1, the flash gas contains gases besides CH<sub>4</sub> and must be multiplied by the tank vent CH<sub>4</sub> content. The Member must follow the same procedure presented in the previous example to calculate the CH<sub>4</sub> content. Thus, the CH<sub>4</sub> emissions are:

$$E (\text{CH}_4) = 6.44 \text{ tonnes CH}_4/\text{yr}$$

### C - EUB RULE-OF-THUMB

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This is a simple correlation that relates the gas volume to the oil production volume and the amount of pressure drop in the tank. This approach tends to yield conservatively high flashing loss estimates and is recommended for facilities with low oil volumes, established pools, mature pools with declining GOR's, and some heavy oil production facilities.

#### Equation 17hh: EUB Rule of Thumb

$$V_s = 0.0257 \times V_o \times \Delta P$$

where,

$V_s$  = volume of gas released, m<sup>3</sup>

$V_o$  = oil production volume, m<sup>3</sup>

$\Delta P$  = pressure drop to atmospheric tank, KPa

You must convert the flash gas emissions estimated using the EUB rule-of-thumb approach to a CH<sub>4</sub> emissions basis. As noted earlier, a default of 27.4 volume percent CH<sub>4</sub> is assumed in the absence of site-specific data.<sup>61</sup> An example illustrating the calculations is presented below.

#### 17.9.3: Example: Flashing Loss Emissions Calculation using the EUB Rule-of-Thumb Correlation<sup>62</sup>

<sup>61</sup> Average tank vent gas composition from Ogle, March 1997/ Ogle, May 1997; Picard, Vol. III, 1992.

<sup>62</sup> API 2009. "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry," Prepared for American Petroleum Institute (API), Prepared by URS Corp., August 2009. Section 5 - Process and Vented Emission Estimation Methods.

The O&GP Installation is the same one described in Section 17.9.1 and Section 17.9.2. For illustrative purposes, this exhibit shows how CO<sub>2</sub> emissions would be quantified as well. For this installation, the CO<sub>2</sub> tank vent concentration is assumed to be approximately 4.5 volume percent. You can calculate the flashing loss emissions using Equation 17hh.

$$\text{Crude oil production} = 451 \text{ bbl/day (71.70 m}^3\text{/day)}$$

First, the input parameters must be converted to the proper SI units for use in the equation. The separator gauge pressure, 28.6 psig, is equal to the pressure drop from the separator to the atmospheric storage tank (i.e., 43.3 psia - 14.7 psia = 28.6 psi). Thus, the pressure drop in kPa is:

$$\Delta P = (28.6 \text{ psi}) \times (6.894757 \text{ kPa/psi}) = 197.2 \text{ kPa}$$

The flash gas vent flow rate is calculated below:

$$V_s = 0.0257 \times (71.7) \times (197.2) = 363.4 \text{ m}^3\text{/day}$$

The flash gas contains gases besides CH<sub>4</sub> and must be multiplied by the tank vent CH<sub>4</sub> content. The tank vent CH<sub>4</sub> content is not known so the recommended default concentration of 27.4 volume percent CH<sub>4</sub> will be used. Thus, the CH<sub>4</sub> emissions are:

$$E (\text{CH}_4) = 24.56 \text{ tonnes CH}_4\text{/yr}$$

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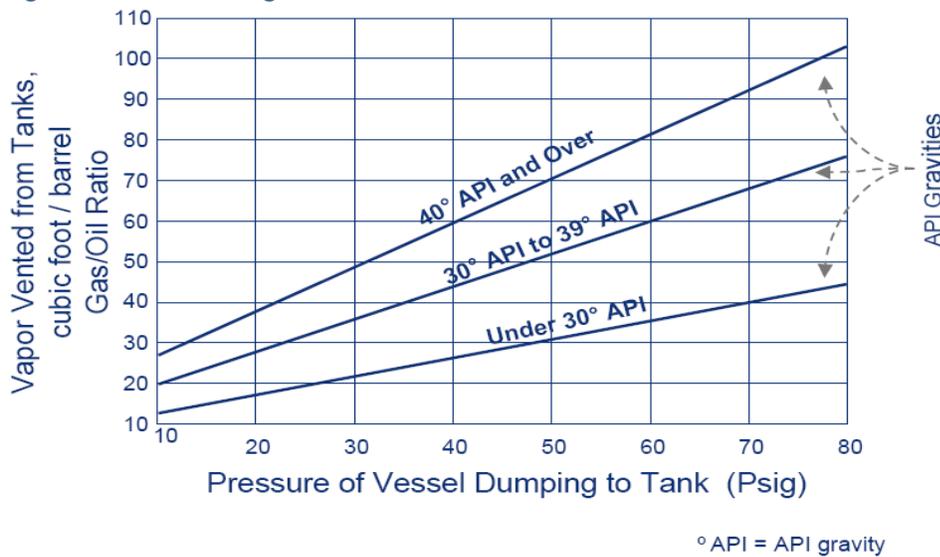
O&GP PR-25:

## FLASHING LOSS CHART METHODOLOGY BASED ON API GRAVITY AND PRESSURE

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You can use the following chart to estimate crude oil flashing losses. It provides the flash gas volume-to-oil ratio from the crude oil tank as a function of the crude oil API gravity and pressure of the separator immediately upstream of the tank.

Figure 17.2 – Flashing Losses Chart<sup>63</sup>



Source: U.S. Environmental Protection Agency (EPA). *Vapor Recovery Tower/VRU Configuration*, Lessons Learned from Natural Gas STAR, Occidental Petroleum Corporation and California Independent Petroleum Association, Producers Technology Transfer Workshop, Long Beach, California, August 21, 2007. [http://www.epa.gov/gasstar/documents/vrt\\_vru\\_configuration\\_08\\_21\\_07.pdf](http://www.epa.gov/gasstar/documents/vrt_vru_configuration_08_21_07.pdf)

O&GP PR-26:

## FLASHING LOSSES EMISSION FACTOR METHODOLOGY

This approach uses data from two published studies, API/GRI (Ogle, March 1997; Ogle, May 1997) and the Canadian Association of Petroleum Producers (CAPP) (Picard, Vol. III, 1992), to derive emission factors for production crude oil storage tanks. The measurement programs included gas streams with varying CH<sub>4</sub> contents. In order to combine the measurements, each was converted to a common production segment CH<sub>4</sub> concentration of 78.8 percent. This approach should be used only if very limited data are available. CH<sub>4</sub> emission factors are presented in Table 17.15.

<sup>63</sup> API 2009. "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry," Prepared for American Petroleum Institute (API), Prepared by URS Corp., August 2009. Section 5 - Process and Vented Emission Estimation Methods.

**Table 17.15 – CH<sub>4</sub> Flashing Loss Emission Factors for Crude Oil Storage Tanks<sup>64</sup>**

Source	CH <sub>4</sub> Flashing Loss Emission Factor <sup>a,b,c,d</sup>	
Combined API/GRI and CPA data	46.18	Scf/bbl
	1.954	lb/bbl crude
	8.86E-04	tonnes/bbl crude
	5.57E-03	tonnes/m <sup>3</sup> crude

Sources:

<sup>a</sup> Ogle, L.D. *Validation of a Petroleum Production Tank Emission Model*, Final Report, GRI-97/0117. American Petroleum Institute and Gas Research Institute, March 1997.

<sup>b</sup> Ogle, L.D. *Evaluation of a Petroleum Production Tank Emission Model*, Final Report. American Petroleum Institute, Gas Research Institute, and Canadian Association of Petroleum Producers, May 1997.

<sup>c</sup> Picard, D. J., B. D. Ross, and D. W. H. Koon. *Inventory of CH<sub>4</sub> and VOC Emissions from Upstream Oil and Gas Operations in Alberta*, Volume III Results of the Field Validation Program, Canadian Petroleum Association, March 1992, pp. 75-81.

<sup>d</sup> Corrected to average CH<sub>4</sub> concentration for natural gas industry production operations of 78.8%. Source for 78.8% CH<sub>4</sub> concentration:

Shires, T.M., and M.R. Harrison. *Methane Emissions from the Natural Gas Industry, Volume 6: Vented and Combustion Source Summary*, Final Report, GRI-94/0257.23 and EPA-600/R-96-080f, Gas Research Institute and US Environmental Protection Agency, June 1996.

**Table 17.16 – CH<sub>4</sub> Flashing Loss Emission Factors from Production Condensate<sup>65</sup>**

Source	CH <sub>4</sub> Flashing Loss Emission Factor <sup>a,b,c,d</sup>	
Hendler et al., 2006	46.18	lb/bbl condensate
	2.30E-03	tonnes/bbl condensate
	1.45E-02	tonnes/bbl condensate

#### 17.9.4: Example: Flashing Loss Emissions Calculation using the Emission Factor<sup>66</sup>

An O&GP Installation produces 451 bbl/day of crude oil. The separator gas (to sales pipeline) CH<sub>4</sub> content is 58 volume percent. You must calculate the CH<sub>4</sub> emissions using the emission factors Table 17.15.

Note that the emission factor from the table is based on 78.8 mole percent CH<sub>4</sub> in the separator gas, so this emission factor must be corrected to 58 mole percent based on the composition for this example.

$$E (\text{CH}_4) = (451 \text{ bbl oil/day}) \times (365 \text{ day/yr}) \times (8.86 \times 10^{-4} \text{ tonnes CH}_4/\text{bbl oil}) \times (58 \text{ mole \% CH}_4 / 78 \text{ mole \% CH}_4)$$

$$E (\text{CH}_4) = 107.4 \text{ tonnes CH}_4/\text{yr}$$

<sup>64</sup> API 2009. "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry," Prepared for American Petroleum Institute (API), Prepared by URS Corp., August 2009. Appendix B.

<sup>65</sup> Ibid.

<sup>66</sup> API 2009. "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry," Prepared for American Petroleum Institute (API), Prepared by URS Corp., August 2009. Section 5 - Process and Vented Emission Estimation Methods.

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## 17.10 Working/Breathing Losses from Tanks

Working loss emissions occur because of evaporative losses of the liquid as a result of changes in liquid level in the tank (emptying and filling activities). Standing or breathing losses occur during storage of the liquid, and can result from diurnal temperature changes.

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O&GP PR-27:

### CALCULATING CH<sub>4</sub> AND CO<sub>2</sub> EMISSIONS FROM WORKING AND BREATHING LOSSES

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Most of the CH<sub>4</sub> and CO<sub>2</sub> emissions from crude storage tanks occur as a result of flashing, working and breathing loss emissions are very small in production activities and virtually non-existent in the downstream segments.

U.S. EPA provides a methodology to estimate tank hydrocarbon emissions due to tank working and standing losses. This methodology can be found in Chapter 7 of AP-42.<sup>67</sup> This methodology forms the basis for the TANKS software program (EPA, 1999).<sup>68</sup> EPA's methodology estimates total hydrocarbon (THC) or volatile organic compound (VOC). Members must estimate total tank emissions and then multiply the total emissions by the concentration of CH<sub>4</sub> and CO<sub>2</sub> in the tank vent stream. CH<sub>4</sub> and CO<sub>2</sub> concentrations should be based on site-specific data.

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## 17.11 Produced Water Tank Emissions

In Canada the norm is to collect produced water in atmospheric tanks. Surface water run-off is collected in surface ponds for treatment or disposal. These ponds could be a source of GHG emissions from biological activity (discussed in Section 11) but would not be a source of CH<sub>4</sub> or CO<sub>2</sub> emissions from dissolved gases. For atmospheric storage tanks containing produced water the methodology for calculating GHG emissions is similar to that for calculating flashing losses from oil or condensate storage tanks. When produced water comes from a vessel at elevated pressure and enters a tank at atmospheric pressure some of the dissolved CH<sub>4</sub> flashes off and is released to the atmosphere. The produced water is usually re-injected into a disposal well or sometimes into a producing formation for pressure maintenance. In the case of oil sands, produced water is recycled (treated and fed back into the steam generation system). So, significant evaporation does not occur.

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<sup>67</sup> The emission estimation equations in Chapter 7 of AP-42 were developed by API (API retains the copyright of the equations but has granted EPA permission to publish them).

<sup>68</sup> The TANKS software available at: <http://www.epa.gov/ttn/chief/software/tanks/index.html>

## CALCULATING CH<sub>4</sub> AND CO<sub>2</sub> EMISSIONS PRODUCED WATER TANKS

As mentioned above, CO<sub>2</sub> and CH<sub>4</sub> emissions from water tanks occur in a manner similar to crude oil storage tank flashing losses, though at a smaller rate. CH<sub>4</sub> emissions from produced water tanks are lower than crude tank flashing losses because CH<sub>4</sub> has a stronger affinity for hydrocarbon oil than it does for water.

Table 17.17 lists emission factors from produced (salt) water tanks. You should use the following table to calculate CH<sub>4</sub> emissions.

**Table 17.17 – Produced Salt Water Tank CH<sub>4</sub> Flashing Emission Factors<sup>69</sup>**

Separator Pressure (psi)	Produced Water Salt Content (%)	GRI/EPA Emissions Rate <sup>a</sup> , original units (10 <sup>6</sup> lb CH <sub>4</sub> /yr)	Water Tank Emission Factor	
			Tonnes CH <sub>4</sub> /1000bbl produced water <sup>b</sup>	Tonnes CH <sub>4</sub> /1000m <sup>3</sup> produced water
50	20	1.6	0.0015	0.009185
250	20	10.8	0.00986	0.06200
250	10	16.4	0.0150	0.09414
250	2	19.4	0.0177	0.11137
<b>250</b>	<b>Average of 10.7<sup>c</sup></b>	--	<b>0.0142</b>	<b>0.08917</b>
1000	20	38.8	0.0354	0.22273
1000	10	58.7	0.0536	0.33697
1000	2	69.5	0.0634	0.39896
<b>1000</b>	<b>Average of 10.7<sup>c</sup></b>	--	<b>0.0508</b>	<b>0.31955</b>

Footnotes and Sources:

<sup>a</sup> Emission factors developed from Table 5-5 of Shires, T.M., and M.R. Harrison. *Methane Emissions from the Natural Gas Industry, Volume 6:*

*Vented and Combustion Source Summary, Final Report*, GRI-94/0257.23 and EPA-600/R-96-080f, Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

<sup>b</sup> Process simulation modeling based on 1990 annual salt water production of 497 million barrels from Energy Environmental Research Center, 1995.

<sup>c</sup> Average of emission factors at 20, 10, and 2% salt.

### 17.12 Vented Emissions from Pneumatic Devices

This section provides a method for calculating vented emissions from pneumatically-powered devices at oil and natural gas wells and equipment that utilize natural gas as a pressurized fluid. These devices are used in a variety of applications, including compressor motor starters, isolation shutoff valves, small pneumatic motors, and for controlling and monitoring gas and liquid flows, temperature in dehydrator regenerators and pressure in flash tanks. While such

<sup>69</sup> API 2009. "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry," Prepared for American Petroleum Institute (API), Prepared by URS Corp., August 2009. Section 5. Table 5-10.

devices can be pneumatic, electric, or mechanical, this section applies only to those that utilize natural gas as a pressurized fluid; these tend to be more commonly employed where access to grid-supplied electricity is limited, but natural gas is plentiful, including wellheads and remote pipeline locations.

As part of normal operation, natural gas powered pneumatic control devices release (or “bleed”) gas to the atmosphere and, consequently, can be a significant source of CH<sub>4</sub> emissions. If the natural gas used by the devices has a naturally occurring CO<sub>2</sub> content, CO<sub>2</sub> emissions can also be significant. Methods for calculating CH<sub>4</sub> and CO<sub>2</sub> emissions from pneumatic devices are provided below. Emissions from gas-driven pneumatic pumps are not included in this section, but are described in Section 17.13.

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O&GP PR-29:

### CALCULATING CH<sub>4</sub> AND CO<sub>2</sub> EMISSIONS FROM NATURAL GAS-DRIVEN PNEUMATIC DEVICES BASED ON BLEED RATES

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This quantification method relies on estimates of device bleed rates, usage information, the CH<sub>4</sub> (or CO<sub>2</sub>) content of the natural gas, and device counts for each natural gas production segment considered in order to calculate CH<sub>4</sub> (or CO<sub>2</sub>) emissions.

This approach involves six steps:

1. Identify the type and number of each pneumatic device employed in a given basin or region;
2. Identify the hours of annual usage of each device type;
3. Determine the appropriate bleed rate for each device type – if the gas system serving the device is pressurized, the device can be assumed to be “bleeding”;
4. Obtain the molar fractions of CH<sub>4</sub> and CO<sub>2</sub> for the natural gas used in each device;
5. Calculate CH<sub>4</sub> and CO<sub>2</sub> emissions for each device; and
6. Convert CH<sub>4</sub> emissions to units of CO<sub>2</sub> equivalent and sum to determine total emissions.

#### STEP 1: IDENTIFY THE TYPE AND NUMBER OF EACH PNEUMATIC DEVICE EMPLOYED.

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Your count must represent the actual inventory of all the natural gas-driven pneumatic devices that are in operation within each of your Oil and Gas Production Installations.

#### STEP 2: IDENTIFY THE HOURS OF ANNUAL USAGE OF EACH DEVICE TYPE

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Obtain an estimate of the number of hours each device is used over the course of the reporting year from service records, maintenance logs, or other relevant records pertaining to equipment usage.

If an actual inventory of the number of hours each device type is used is not available, you can assume a default usage rate of 8760 hours per year per device (365 days x 24 hours), as many production systems and wells are operational and pressurized year round.

### STEP 3: DETERMINE THE APPROPRIATE BLEED RATE FOR EACH DEVICE.

A direct measurement of the bleed rate of each device can be accomplished by installing gas flow meters upstream and downstream of each device. The difference between the upstream and downstream flow rate is equal to the bleed rate for that device. In some cases, an individual meter can be used when there is adequate space in the line. You should measure bleed rates in standard cubic feet per day.

If it is not possible for you to directly measure the bleed rate for each device, many manufacturers can provide measured bleed rates for their devices. This information may be listed directly on the device, or you can obtain it directly from the manufacturer. Alternatively, Table 17.18 lists default bleed rates for a variety of devices.

**Table 17.18 – Default Bleed Rates for Various Pneumatic Device Types for Natural Gas Production<sup>70</sup>**

Device Type	Emission Factor <sup>a</sup> , Original Units		Emission Factor <sup>b</sup> , Converted to Tonnes Basis	
<b>Production Segment</b>			Based on 78.8 mole% CH <sub>4</sub> <sup>a</sup>	
Continuous bleed <sup>a</sup>	654	scfd gas/device	3.608	tonnes/device-yr
Continuous bleed, low/no-bleed <sup>c</sup>	33.4	scfd gas/device	0.184	tonnes/device-yr
Continuous bleed, high-bleed <sup>c</sup>	896	scfd gas/device	4.941	tonnes/device-yr
Intermittent bleed <sup>a</sup>	323	scfd gas/device	1.782	tonnes/device-yr
Production average <sup>a</sup> (if device type is unknown)	345	scfd CH <sub>4</sub> /device	2.415	tonnes/device-yr
Transmitter (140 kPag) <sup>d</sup>	0.12	m <sup>3</sup> gas/hr/device	0.56	tonnes/device-yr
Transmitter (240 kPag) <sup>d</sup>	0.2	m <sup>3</sup> gas/hr/device	0.94	tonnes/device-yr
Controller (140 kPag) <sup>d</sup>	0.6	m <sup>3</sup> gas/hr/device	2.8	tonnes/device-yr
Controller (240 kPag) <sup>d</sup>	0.8	m <sup>3</sup> gas/hr/device	3.7	tonnes/device-yr
Controller (pressure not specified) <sup>e</sup>	0.1996	m <sup>3</sup> gas/hr/device	0.9333	tonnes/device-yr
I/P Transducer (140 kPag) <sup>d</sup>	0.6	m <sup>3</sup> gas/hr/device	2.8	tonnes/device-yr
I/P Transducer (240 kPag) <sup>d</sup>	0.8	m <sup>3</sup> gas/hr/device	3.7	tonnes/device-yr
P/P Positioner (140 kPag) <sup>d</sup>	0.32	m <sup>3</sup> gas/hr/device	1.5	tonnes/device-yr
P/P Positioner (240 kPag) <sup>d</sup>	0.5	m <sup>3</sup> gas/hr/device	2.3	tonnes/device-yr
I/P Positioner (140 kPag) <sup>d</sup>	0.4	m <sup>3</sup> gas/hr/device	1.9	tonnes/device-yr
I/P Positioner (240 kPag) <sup>d</sup>	0.6	m <sup>3</sup> gas/hr/device	2.8	tonnes/device-yr

Sources for Tables 17.17 and 17.18:

<sup>70</sup> API 2009. "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry," Prepared for American Petroleum Institute (API), Prepared by URS Corp., August 2009. Section 5, Table 5-15.

<sup>a</sup> Shires, T.M. and M.R. Harrison. *Methane Emissions from the Natural Gas Industry, Volume 12: Pneumatic Devices*, Final Report, GRI-94/0257.29 and EPA-600/R-96-080l, Gas Research Institute and U.S. Environmental Protection Agency, June 1996; and Harrison, M.R., L.M. Campbell, T.M. Shires, and R.M. Cowgill. *Methane Emissions from the Natural Gas Industry, Volume 2: Technical Report*, Final Report, GRI-94/0257.1 and EPA-600/R-96-080b, Gas Research Institute and U.S. Environmental Protection Agency, June 1996. The average CH<sub>4</sub> concentration associated with these emission factors is provided in Table E-4.

<sup>b</sup> CH<sub>4</sub> emission factors converted from scf or m<sup>3</sup> are based on 60°F and 14.7 psia.

<sup>c</sup> High-bleed devices refer to devices with leak rates greater than 6 scf/hr while low-bleed devices are 6 scf/hr or lower. Developed from data used for Volume 12 of the GRI/EPA natural gas industry CH<sub>4</sub> emissions study (Shires, 1996). Refer to Appendix B for the development of these emission factors.

<sup>d</sup> Canadian Association of Petroleum Producers (CAPP), *Calculating Greenhouse Gas Emissions*, Table 1-12, Canadian Association of Petroleum Producers, Publication Number 2003-03, April 2003. Note that the emission factors provided by this source are for the total gas emitted and were converted to a CH<sub>4</sub> basis using the CH<sub>4</sub> content shown in the table. I/P refers to a device that converts electric current to pneumatic pressure. P/P refers to a device that converts pneumatic pressure to pneumatic pressure.

<sup>e</sup> Canadian Association of Petroleum Producers (CAPP), *Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities*, Table 3-4, Canadian Association of Petroleum Producers, Publication Number 2002-0009, May 2002. Factor shown is based on data collected in Alberta, and was converted from a total gas basis to a CH<sub>4</sub> basis using the CH<sub>4</sub> content shown in the table.

**Table 17.19 – Default Bleed Rates for Various Pneumatic Device Types for Natural Gas Processing<sup>71</sup>**

Device Type	Emission Factor <sup>a</sup> , Original Units <sup>72</sup>	
<b>Processing</b>		
Continuous bleed	497,584	scf gas/device-yr
Piston valve operator	48	scf gas/device-yr
Pneumatic/hydraulic valve operator	5,627	scf gas/device-yr
Turbine valve operator	67,599	scf gas/device-yr
Processing average (if device type is unknown)	164,949	scf CH <sub>4</sub> /plant-yr
	7.431 <sup>g</sup>	scf CH <sub>4</sub> /MMscf processed

#### STEP 4: OBTAIN THE MOLAR FRACTIONS OF CH<sub>4</sub> AND CO<sub>2</sub> FOR THE NATURAL GAS USED IN EACH DEVICE.

You must determine the CH<sub>4</sub> and CO<sub>2</sub> content of the natural gas used in the pneumatic devices. You should collect and analyze fuel according to applicable industry-approved, national, or international technical standards regarding sampling frequency, procedures, and preparation. For additional resources on gas composition analysis methods, refer to:

- ASTM D1945-03: Standard Test Method for Analysis of Natural Gas by Gas Chromatography
- ASTM D4984-06: Standard Test Method for Carbon Dioxide in Natural Gas Using Length-of-Stain Detector Tubes

<sup>71</sup> API 2009. "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry," Prepared for American Petroleum Institute (API), Prepared by URS Corp., August 2009. Section 5, Table 5-15.

<sup>72</sup> Equation specifies bleed rate in scfd, but then multiplies by hours/year

If you do not have measured data on the CH<sub>4</sub> content of the natural gas, you can use the default CH<sub>4</sub> content values for production, processing, transmission and storage, and distribution segments of the natural gas industry in Table 17.20

**Table 17.20 – Default Molar Fraction Values of CH<sub>4</sub> Used in Pneumatic Devices**<sup>73</sup>

Industry Segment	Molar Fraction of CH <sub>4</sub>
Production	0.788
Processing	0.868
Transmission and Storage	0.934
Distribution	0.949

**STEP 5: CALCULATE CH<sub>4</sub> AND CO<sub>2</sub> EMISSIONS FOR EACH DEVICE.**

Using the values obtained in steps 1-4, above, you can calculate CH<sub>4</sub> and CO<sub>2</sub> emissions from all pneumatic devices using Equation 17ii below.

**Equation 17ii: Calculating CH<sub>4</sub> or CO<sub>2</sub> Emissions from Natural Gas-Driven Pneumatic Devices based on Bleed Rates**

$$E_{CH_4/CO_2} = \sum N_i \times \sigma_{bleed} \times (1.0 \text{ lb – mole})/379.3 \text{ scf} \times MW_{CH_4/CO_2} \times f_{CH_4/CO_2} \times t_{annual} / 2204.62$$

where:

$E_{CH_4/CO_2}$  = the total pneumatic device venting emissions of CH<sub>4</sub> or CO<sub>2</sub> from each production segment (tonne/yr)

$N_i$  = the number of devices of type i in the basin or region

$\sigma_{bleed}$  = the bleed rate of gas from device type i (scfd)

$MW_{CH_4/CO_2}$  = the molecular weight of CH<sub>4</sub> or CO<sub>2</sub> (16 lb/lb-mole or 44 lb/lb-mole)

$f_{CH_4/CO_2}$  = is the molar fraction of CH<sub>4</sub> or CO<sub>2</sub> in the gas

$t_{annual}$  = the annual usage of the pneumatic device (days/yr)

2204.62 = conversion factor from lb to t

<sup>73</sup> API 2009. "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry," Prepared for American Petroleum Institute (API), Prepared by URS Corp., August 2009. Section 5. Table 5-15.

## STEP 6: CONVERT CH<sub>4</sub> EMISSIONS TO UNITS OF CO<sub>2</sub> EQUIVALENT.

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To convert CH<sub>4</sub> emissions to tonnes of CO<sub>2</sub>-e, you must multiply the quantity of CH<sub>4</sub> calculated in Step 5 by its GWP (21). Sum all values to determine the total emissions from pneumatic devices in tonnes CO<sub>2</sub>-e.

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### 17.13 Vented Emissions from Natural Gas-Driven Chemical Injection Pumps

This section provides a method for calculating vented emissions from chemical injection pumps (CIPs) at oil and natural gas wells and facilities that utilize natural gas to act on a diaphragm or piston. These pumps are used to inject precise amounts of chemicals into process equipment lines. Typical chemicals injected into the process lines include anti-foam agents, methanol, biocides, demulsifiers, clarifiers, corrosion inhibitors, scale inhibitors, hydrate inhibitors, paraffin dewaxers, surfactants, oxygen scavengers, and hydrogen sulfide (H<sub>2</sub>S) scavengers. While CIPs can be pneumatic, electric, or mechanical, this section applies only to those that utilize natural gas as a pressurized fluid. CIPs tend to be more commonly employed where access to grid-supplied electricity is limited, but natural gas is plentiful, including wellheads and remote pipeline locations. CIPs are typically piston or diaphragm types, and operate across a range of pressures.

As part of normal operation, natural gas-driven CIPs a small amount of natural gas is vented to the atmosphere during the actuation of the pump's piston or diaphragm, and, consequently, can be a significant source of CH<sub>4</sub> emissions. If the natural gas used by the CIPs has a naturally occurring CO<sub>2</sub> content, CO<sub>2</sub> emissions can also be significant. Methods for calculating CH<sub>4</sub> and CO<sub>2</sub> emissions from natural gas-driven CIPs are provided below. Emissions from other gas-driven pneumatic devices are not included in this section, but are described in Section 17.12.

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#### O&GP PR-30:

#### METHOD FOR CALCULATING CH<sub>4</sub> AND CO<sub>2</sub> EMISSIONS FROM NATURAL GAS-DRIVEN CHEMICAL INJECTION PUMPS BASED ON EMISSION FACTORS

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This method relies on estimates of the quantity of gas processed, utilization rates of the CIPs, and natural gas composition information in order to calculate CH<sub>4</sub> and CO<sub>2</sub> emissions.

This approach involves six steps:

1. Identify the type and number of each CIPs employed in a given basin or region;
2. Identify the hours of annual usage of each CIP;
3. Determine the appropriate emission rate for each device type;
4. Obtain the molar fractions of CH<sub>4</sub> and CO<sub>2</sub> for the natural gas used in each CIP;
5. Calculate CH<sub>4</sub> and CO<sub>2</sub> emissions for each CIP; and
6. Convert CH<sub>4</sub> emissions to units of CO<sub>2</sub>-e and sum to determine total emissions.

### STEP 1: IDENTIFY THE TYPE AND NUMBER OF EACH CIP EMPLOYED IN A GIVEN BASIN OR REGION.

---

Use a count that represents the actual inventory of all the natural gas-driven CIPs that are in operation in each installation by type.

### STEP 2: IDENTIFY THE HOURS OF ANNUAL USAGE OF EACH DEVICE TYPE

---

Obtain an estimate of the number of hours each CIP is used over the course of the reporting year from service records, maintenance logs, or other relevant records pertaining to equipment usage.

If an actual inventory of the number of hours each CIP type is used is not available, a default usage rate of 8760 hours per year (365 days x 24 hours) per CIP can be assumed, as many production systems and wells are operational and pressurized year round.

### STEP 3: DETERMINE THE APPROPRIATE EMISSION RATE FOR EACH DEVICE.

---

A direct measurement of the emission rate of each CIP can be accomplished by installing gas flow meters upstream and downstream of each pump. The difference between the upstream and downstream flow rate is equal to the emission rate for that pump. In some cases, you can use an individual meter when there is adequate space in the line. You should measure emission rates in standard cubic feet per day.

If it is not possible to directly measure the emission rate for each CIP, many manufacturers can provide measured emission rates for their pumps that can be used in combination with Equation 17jj to calculate the volume of gas emitted.

Equation 17jj: Calculating the Volume of Gas Emitted from a Pneumatic Pump from Manufacturer Data
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$$V_G = (P_O + P_A) / 14.7 \times T_A / (459.7 + T_G) \times V_L \times [1 + I]$$

where:

$V_G$  = gas loss from CIP (scf/yr)

$P_O$  = outlet pressure from the pump (psig)

$P_A$  = atmospheric pressure (psig)

14.7 = atmospheric pressure (psig)

**Equation 17jj: Calculating the Volume of Gas Emitted from a Pneumatic Pump from Manufacturer Data**

$T_A$  = atmospheric temperature (°R)

459.7 = conversion from °F to °R

$T_G$  = gas temperature (°F)

$V_L$  = volume of liquid pumped (ft<sup>3</sup>/yr) from measurement data or calculated using Equation 17-36

[1+I] = manufacturer specific pump inefficiency, or assumed default of 30%

If you do not have measured data for the volume of pumped liquid, you can calculate it using Equation 17kk below.

**Equation 17kk: Calculating the Volume of Liquid Pumped from a Pneumatic Pump**

$$V_L = (V_S/7.48) \times N \times T$$

where:

$V_L$  = volume of liquid pumped (ft<sup>3</sup>/yr)

$V_S$  = volume of liquid pumped per stroke (gal/stroke)

7.48 = conversion from gal to scf

$N$  = number of strokes per minute

14.7 = atmospheric pressure (psig)

$T$  = annual operational time (min/year)

Alternatively, Table 17.21 lists default CH<sub>4</sub> emission rates for a variety of CIPs. The emission rates are provided by pump type and operating pressure. The table also contains a default averaged rate if information about the pump is not known.

**Table 17.21 – Default CH<sub>4</sub> Emission Rates for Various CIPs by Type and Operating Pressure<sup>74</sup>**

Pump Type / Operating Pressure	CH <sub>4</sub> Emission Factor, Original Units	CH <sub>4</sub> Emission Factor, Converted to Tonnes Basis <sup>a</sup> (based on 78.8 mole% CH <sub>4</sub> ) <sup>b</sup>
Piston pumps / 207 kPag	48.9 scfd/pump <sup>b</sup>	0.342 tonnes/pump-yr
Piston pumps / 140 kPag	0.04 m <sup>3</sup> /hour/pump <sup>c</sup>	0.19 tonnes/pump-yr
Piston pumps / 240 kPag	0.06 m <sup>3</sup> /hour/pump <sup>c</sup>	0.28 tonnes/pump-yr
Diaphragm pumps / pressure unspecified	446 scfd/pump <sup>b</sup>	3.121 tonnes/pump-yr
Diaphragm pumps / 140 kPag	0.4 m <sup>3</sup> /hour/pump <sup>c</sup>	1.9 tonnes/pump-yr
Diaphragm pumps / 240 kPag	0.6 m <sup>3</sup> /hour/pump <sup>c</sup>	2.8 tonnes/pump-yr
Average (if pump type unknown)	248 scfd/pump <sup>b</sup> 0.3945 m <sup>3</sup> /hour/pump <sup>c</sup>	1.737 tonnes/pump-yr 1.845 tonnes/pump-yr

Sources:

<sup>a</sup> CH<sub>4</sub> emission factors converted from scf or m<sup>3</sup> are based on 60°F and 14.7 psia.

<sup>b</sup> Shires, T.M. *Methane Emissions from the Natural Gas Industry, Volume 13: Chemical Injection Pumps*, Final Report, GRI-94/0257.30 and EPA-600/R-96-080m, Gas Research Institute and U.S. Environmental Protection Agency, June 1996. The average CH<sub>4</sub> concentration associated with these emission factors is provided in Table E-4.

<sup>c</sup> Canadian Association of Petroleum Producers (CAPP), *Calculating Greenhouse Gas Emissions*, Table 1-12, Canadian Association of Petroleum Producers, Publication Number 2003-03, April 2003. Note that the emission factors provided by this source are for the total gas emitted and were converted to a CH<sub>4</sub> basis using the CH<sub>4</sub> content shown in the table.

<sup>c</sup> Canadian Association of Petroleum Producers (CAPP), *Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities*, Table 3-4, Canadian Association of Petroleum Producers, Publication Number 2002-0009, May 2002. Factor shown is based on data collected in Alberta, and was converted from a total gas basis to a CH<sub>4</sub> basis using the CH<sub>4</sub> content shown in the table.

#### STEP 4: OBTAIN THE MOLAR FRACTIONS OF CH<sub>4</sub> AND CO<sub>2</sub> FOR THE NATURAL GAS USED IN EACH CIP.

You must determine the CH<sub>4</sub> and CO<sub>2</sub> content of the natural gas used in the CIPs. You should collect and analyze fuel data according to applicable industry-approved, national, or international technical standards regarding sampling frequency, procedures, and preparation. For additional resources on gas composition analysis methods, refer to:

- ASTM D1945-03: Standard Test Method for Analysis of Natural Gas by Gas Chromatography
- ASTM D4984-06: Standard Test Method for Carbon Dioxide in Natural Gas Using Length-of-Stain Detector Tubes

If you do not have measured data on the CH<sub>4</sub> of the natural gas, you can use a default CH<sub>4</sub> molar fraction value of 0.788.

<sup>74</sup> API 2009. "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry," Prepared for American Petroleum Institute (API), Prepared by URS Corp., August 2009. Section 5. Table 5-16.

## STEP 5: CALCULATE CH<sub>4</sub> AND CO<sub>2</sub> EMISSIONS FOR EACH CIP AND SUM TO OBTAIN TOTAL EMISSIONS

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Using the values obtained in steps 1-4, above, you can calculate CH<sub>4</sub> and CO<sub>2</sub> emissions from all pneumatic devices using Equation 17II, below.

### Equation 17II: Calculating CH<sub>4</sub> and CO<sub>2</sub> Emissions from Natural Gas-Driven Chemical Injection Pumps based on Emissions Factors

$$E_{CH_4CO_2} = \sum N_i \times \sigma_{bleed, i} \times (1.0 \text{ lb - mole})/379.3 \text{ scf} \times MW_{CH_4/CO_2} \times f_{CH_4/CO_2} \times t_{annual} / 2204.62$$

where:

$E_{CH_4/CO_2}$  = the total CIP emissions of CH<sub>4</sub> or CO<sub>2</sub> (tonne/yr)

$N_i$  = the number of CIPs of type  $i$  in the installation

$\sigma_{bleed, i}$  = the emission rate of gas from CIP type  $i$  (scfd)

$MW_{CH_4/CO_2}$  = the molecular weight of CH<sub>4</sub> or CO<sub>2</sub> (16lb/lb-mole or 44lb/lb-mole)

$f_{CH_4/CO_2}$  = is the molar fraction of CH<sub>4</sub> or CO<sub>2</sub> in the gas

$t_{annual}$  = the annual usage of the CIP (hr/yr or days/yr)

2204.62 = conversion factor from lb to t

## STEP 6: CONVERT CH<sub>4</sub> EMISSIONS TO UNITS OF CO<sub>2</sub> EQUIVALENT.

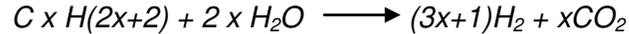
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To convert CH<sub>4</sub> emissions to tonnes of CO<sub>2</sub>-e, you should multiply the quantity of CH<sub>4</sub> calculated in Step 5 by its GWP (21). Sum all values to determine the total emissions from pneumatic devices in tonnes CO<sub>2</sub>-e.

### 17.14 Process Emissions - Hydrogen Unit

This section presents methodologies to calculate GHG emissions from hydrogen units operations used in the Oil Sands and Heavy Oil Upgrading Industry. The majority of Oil Sands and Heavy Oil facilities in North America are located in the Canadian Province of Alberta, and are regulated by Alberta Environment (AENV), Environment Canada, and Alberta's Energy Resources Conservation Board (ERCB).

Hydrogen units are used to generate hydrogen (H<sub>2</sub>) as a product of the reaction between hydrocarbons and steam (H<sub>2</sub>O). Equation 17mm presents the chemical reaction that has to occur in order to obtain H<sub>2</sub>.

**Equation 17mm: Chemical Reaction to Obtain Hydrogen**

The quantity of H<sub>2</sub> generated depends on the carbon-to-hydrogen ratio of the feed gas. In most cases, H<sub>2</sub> is made from natural gas, but in the OS/HOU industry, refinery fuel gas or butane can also be used as feedstock. The CO<sub>2</sub> generated during this process doesn't include CO<sub>2</sub> emissions from process heater(s) associated with the hydrogen unit. You should treat these emissions like the combustion sources described in Chapter 12 of this protocol.

O&GP PR-31:

**MATERIAL BALANCE EMISSIONS ESTIMATION**

You can use the specific feed gas composition to estimate vented CO<sub>2</sub> emissions from hydrogen units. This methodology can be based on either the volume of feedstock used or the hydrogen production rate. Both calculation methods are described below.

The first method to quantify process emissions from a hydrogen unit is a material balance approach which is based on the feedstock rate and the carbon content of the specific feed gas.

**Equation 17nn: Material Balance Emissions Estimation**

$$E(CO_2) = FR \times CF [(44 \text{ mass units } CO_2/\text{mole}) / (12 \text{ mass units } C/\text{mole})]$$

where,

$E(CO_2)$  = emissions of CO<sub>2</sub>, in units of mass per year (i.e. tonnes/yr)

$FR$  = feedstock rate, in units of mass per year (excluding H<sub>2</sub>O fed) (tonnes/yr)

$CF$  = weight fraction of carbon in feedstock

44 = molecular weight of CO<sub>2</sub>

12 = molecular weight of carbon

Note that some of the carbon in the feedstock is entrained as CH<sub>4</sub> in the hydrogen product, and will be accounted for through combustion of the product (e.g. in a fuel gas system). If the fraction of carbon in the feedstock ( $CF$ ) includes the portion of the carbon accounted for through

other end uses, these emissions will be double counted. To avoid double counting, you must subtract the quantity of carbon accounted for elsewhere from the feedstock rate.<sup>75</sup>

#### 17.14.1: Example: Material Balance Calculation of Hydrogen Unit Emissions

An oil and gas production facility uses a hydrogen unit to generate hydrogen gas from a natural gas supply. Calculating CO<sub>2</sub> emissions from the plant using the material balance method outlined in Equation 17nn requires information on the carbon content of the feed gas, and the quantity of feed gas consumed annually. In this case, the natural gas is determined to have the following composition (by molar percent): CH<sub>4</sub> = 90%, C<sub>2</sub>H<sub>6</sub> = 5%, C<sub>4</sub>H<sub>10</sub> = 2%, inert materials = 3%. The plant uses 5000 tonnes of natural gas per year.

The producer can calculate the carbon content of the feed gas mixture from the molar percent of its constituent gases from the plant. The first step is to calculate the molecular weight of the feed gas by taking the average molecular weight of the constituent gases, weighted by their molar percent:

$$\text{MW Mixture} = \sum (\text{Mole \% } i \times \text{MW}_i)$$

Where:

MW Mixture = molecular weight of the mixture  
 Mole % i = molar percent of individual gas, i  
 MW i = molecular weight of individual gas, i

Given the molecular weight of the feed gas, calculate the weight percent of each constituent gas by multiplying its molar percent value by its molecular weight, then dividing by the molecular weight of the feed gas:

$$\text{WT \% } i = (\text{Mole \% } i \times \text{MW}_i) / \text{MW Mixture}$$

Where:

WT% i = weight percent of individual gas, i  
 Mole % i = molar percent of individual gas, i  
 MW i = molecular weight of individual gas, i  
 MW Mixture = molecular weight of the mixture

Finally, you can calculate the carbon fraction of the feed gas (percent by weight) by taking the average carbon content (percent by weight) of all the constituent gases, weighted by their weight percent values:

$$\text{CF Mixture} = \sum (\text{Mole \% } i \times \text{MW}_i)$$

<sup>75</sup> API 2009. "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry," Prepared for American Petroleum Institute (API), Prepared by URS Corp., August 2009. Section 5.

Where:

CF Mixture = carbon fraction of the mixture  
CC % i = carbon content of individual gas, i (percent by weight)  
MW i = molecular weight of individual gas, i  
WT% i = weight percent of individual gas, i

Using this approach, the following values are calculated:

Compound in Feed Gas	Mole %	Molecular Weight	Weight %	Carbon Fraction (Wt % C)
CH <sub>4</sub>	90%	16	80.4	0.9
C <sub>2</sub> H <sub>6</sub>	5%	30	8.4	0.1
C <sub>4</sub> H <sub>10</sub>	2%	58	6.5	0.08
N <sub>2</sub>	3%	28	4.7	1.08
<i>Feed Gas</i>		<i>17.9</i>	<i>100</i>	<i>72.4</i>

Using a carbon fraction value of 72.4% and Equation 17nn:

$$E_{\text{CO}_2} = (5000 \text{ tonnes natural gas /year}) \times (72.4 \text{ wt \% C}) \times (44 \text{ mass units CO}_2/\text{mole} / 12 \text{ mass units C/mole})$$

$$E_{\text{CO}_2} = 13,273.2 \text{ tonnes CO}_2$$

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O&GP PR-32:

## STOICHIOMETRIC RATIO APPROACH

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The second approach to calculating process emissions from hydrogen units is a stoichiometric ratio approach. To use this approach, you need to have the H<sub>2</sub> production rate rather than the feedstock rate. This equation is derived from Equation 17nn presented above.

### Equation 17oo: Stoichiometric Ratio Approach

$$E(\text{CO}_2) = H_2R \times [(x \text{ mole CO}_2 / (3x + 1) \text{ mole H}_2) / (44 / \text{molar volume conversion})]$$

where,

$E(\text{CO}_2)$  = emissions of  $\text{CO}_2$ , in units of mass per year (i.e. tonnes/year)

$H_2R$  = rate of hydrogen production, in units of volume per year (i.e. scf/yr)

44 = molecular weight of  $\text{CO}_2$

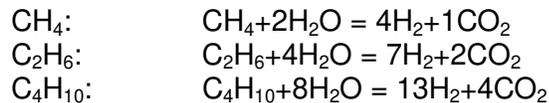
$x$  = stoichiometry from Equation 17mm

Oil sands plants in Alberta should use information about their actual natural gas composition from the pipeline supplier, and measured feed rate.<sup>76</sup>

#### 17.14.2: Example: Stoichiometric Ratio Calculation of Hydrogen Unit Emissions

An facility uses a hydrogen unit to generate hydrogen gas from a natural gas supply. Calculating  $\text{CO}_2$  emissions from the plant using the stoichiometric method outlined in Equation 17oo requires information on the composition of the feedstock, and the quantity of hydrogen gas produced annually. In this case, the natural gas is determined to have the following composition (by molar percent):  $\text{CH}_4 = 90\%$ ,  $\text{C}_2\text{H}_6 = 5\%$ ,  $\text{C}_4\text{H}_{10} = 2\%$ , inert materials = 3%. The plant produces 500 MMscf of hydrogen gas per year.

The first step is to use the chemical formula presented in Equation 17mm to determine the reactions of the individual gases:



With this information, you can determine the carbon-to-hydrogen gas ratio of the reaction products by multiplying the number of molecules of carbon and hydrogen gas in each reaction by their composition in the feed gas:

<sup>76</sup> Natural gas and refinery fuel gas consumed to produce hydrogen must be reported to ERCB. The magnitude of emissions from even a small Oil Sands hydrogen plant (40MMSCFD ~ 192,000 TPY  $\text{CO}_2$ ) dictates a more rigorous approach.

Compound in Feed Gas	# C Atoms in Reaction Products	# H <sub>2</sub> Molecules in Reaction Products	Compound Concentration in Feed Gas	Moles C in Reaction Products	Moles H <sub>2</sub> in Reaction Products
CH <sub>4</sub>	1	4	90%	0.9	3.6
C <sub>2</sub> H <sub>6</sub>	2	7	5%	0.1	0.35
C <sub>4</sub> H <sub>10</sub>	4	13	2%	0.08	0.26
			<i>Totals:</i>	1.08	4.21

Based on these results, the carbon-to-hydrogen gas ratio of the products is 1.08 : 4.21, or 0.257.

Using Equation 17oo, therefore:

$$E_{CO_2} = (5 \times 10^8 \text{ scf/year}) \times (0.257 \text{ moles } CO_2 / \text{mole } H_2) \times (\text{lb-mole } H_2 / 379.3 \text{ scf}) \times (44 \text{ lbs } CO_2 / \text{lb-mole } CO_2) \times (\text{tonne} / 2204.62 \text{ lb})$$

$$E_{CO_2} = 6,761.4 \text{ tonnes/year}$$

## 17.15 Process Emissions – Flue Gas Desulphurization

The combustion of petroleum coke in boilers results in the emission of sulphur dioxide in the flue gas from the boiler due to the presence of sulphur in the fuel. The flue gas desulphurization (FGD) process removes the sulfur dioxide (SO<sub>2</sub>) produced from burning petroleum coke by using limestone (CaCO<sub>3</sub>) to scrub the flue gases in a wet scrubber process. Calcium sulfate dehydrate (gypsum- CaSO<sub>4</sub>) and CO<sub>2</sub> are produced as a result of this reaction.

O&GP PR-33:

### FLUE GAS DESULPHURIZATION EMISSIONS ESTIMATION

You can use a mass balance approach to estimate CO<sub>2</sub> emissions from flue gas desulphurization. The overall accuracy of this approach depends on the degree to which the input materials are measured. This approach is based on the mass of limestone, the limestone percent CaCO<sub>3</sub>, and the conversion factor for CO<sub>2</sub> equivalency.

**Equation 17pp: Calculating CO<sub>2</sub> Emissions from Flue Gas Desulphurization Using Mass Balance<sup>77</sup>**

$$\text{Mass of limestone} \times \text{wt \% } CaCO_3 \times \text{tonnes } CO_2/\text{tonne } CaCO_3$$

<sup>77</sup> U.S. EPA Mandatory Reporting Rule, Equation U-1

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### 17.15.1 Example: Calculation of Flue Gas Desulphurization Emissions

An Oil and Gas Production facility uses a limestone slurry in flue gas desulphurization units (“wet scrubbers”) to reduce sulfur dioxide emissions that result from the combustion of petroleum coke in their boilers. Each year, the scrubbers use 200 tonnes of limestone, which is, on average, 55 percent calcium carbonate by weight.

$$E_{\text{CO}_2} = (200 \text{ tonnes limestone}) \times (55 \text{ weight \% CaCO}_3) \times (44 \text{ tonnes CO}_2 / 100 \text{ tonnes CaCO}_3)$$

$$E_{\text{CO}_2} = 48.4 \text{ tonnes}$$

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### 17.16 Process Emissions – Oil Sands Mine and Ponds

Oil sands facilities, which include mining operations, produce CH<sub>4</sub> emissions from mine and pond surfaces. You can quantify emissions from both of these sources by using flux emission measurements using the U.S. EPA isolation flux chamber design shown in Figure 17.3 (Kienbursh, 1986), and the U.S. EPA protocol for performing flux measurements on surface impoundments (Gholson et al., 1989). This method involves purging the chamber with a known flow rate of purified air until a peak or steady state pollutant concentration is achieved in the exhaust stream, and then collecting a sample of the chamber exhaust for detailed analysis.

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#### O&GP PR-34:

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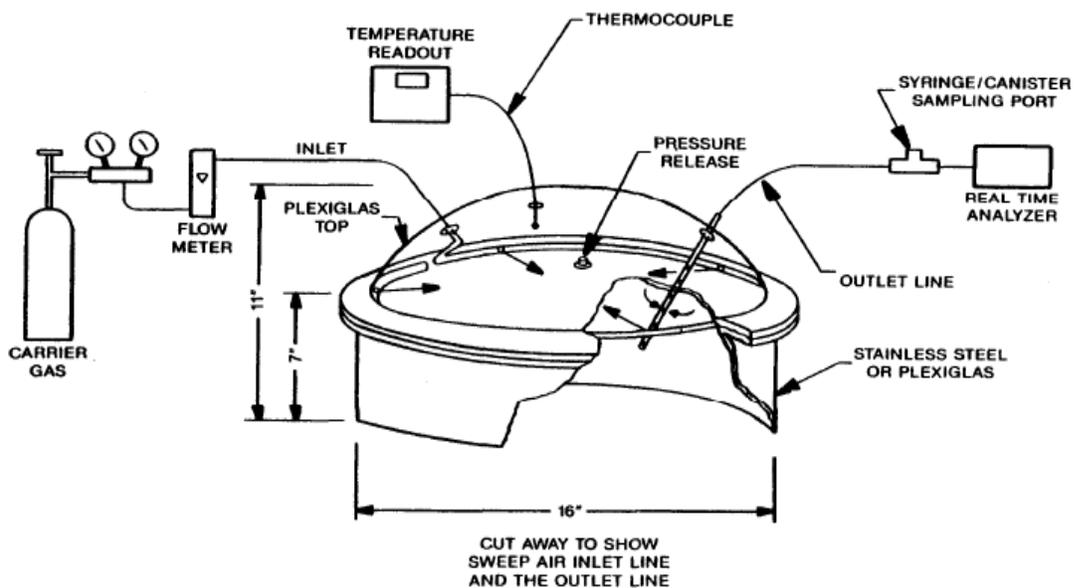
#### OIL SANDS MINE AND POND EMISSIONS ESTIMATION

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Oil sands mine surface emissions are determined by obtaining flux emission readings from various locations and types of surfaces in the mine to determine average emission rates for different surfaces and conditions. These factors are then applied to the total surface area for each category. Factors for mine surfaces vary based on the type of surface area (muskeg, overburden, or oil sand), the length of time the oil sands surface has been exposed, and the oil sands feed grade (wt percent bitumen).

Pond surface emissions are determined by obtaining flux emission readings from several points on each pond to determine an average emission rate for the pond, and then calculating the total emission-based on the total pond surface area. Factors for pond surfaces are facility specific due to differences in the age of ponds, the utilization of the ponds, and the activity level of methanogenic bacteria in the pond along with other factors.

Figure 17.3 – Basic Design of the U.S EPA’s Isolation Flux Chamber



## **PART IV: REPORTING YOUR EMISSIONS**

### **Chapter 18: Additional Reporting Requirements**

REFER TO GRP.

## Chapter 19 Optional Reporting

As discussed in Section 17.2 of the GRP, The Registry encourages Members to exceed their reporting requirements by providing optional data along with their required data. To do so, you may report a wide array of optional data, including: your entity's worldwide emissions, historical emissions, and scope 3 emissions. For a more comprehensive list of optional data, please refer to the GRP.

One type of optional data that can be particularly useful is performance metrics, or GHG intensity ratios. Intensity ratios measure GHG emissions per unit of physical activity (e.g., barrels of oil produced) or economic unit (e.g., total sales in dollars). As noted in the GRP, tracking and reporting intensity ratios can serve a variety of purposes, including:

- Evaluating emissions over time in relation to targets or industry benchmarks;
- Facilitating comparisons between similar businesses, processes, and/or products; and
- Improving public understanding of your entity's emissions profile over time, even as your business activity changes, expands, or decreases.

To date, O&GP companies have voluntarily reported GHG intensity data to a variety of programs, including the California Climate Action Registry and the Carbon Disclosure Project. Based on the data collected under these programs, the most common efficiency metric reported for this sector is: GHG emissions per unit of production.

To calculate this metric, divide your total emissions in CO<sub>2</sub>-e, as calculated using the procedures and methodologies set out in the GRP and O&GP protocols, and then divide the result by your total production of crude oil and natural gas (specified on a consistent basis, such as MMBtu). Oil and Gas Installation-level information on GHG emissions per unit of production is one example of the type of performance metrics you might choose to report to The Registry.

The Registry strongly encourages you to report optional performance metrics data. The number and type of metrics you decide to report, along with the level of detail at which you provide this data, is up to you.

## Chapter 20: Reporting Your Data Using The Registry's Software

REFER TO GRP.

## Chapter 21: Third-Party Verification

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### 21.1 Background: The Purpose of The Registry's Verification Process

REFER TO GRP.

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### 21.2 Activities to Be Completed by the Member in Preparation for Verification

REFER TO GRP.

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### 21.3 Batch Verification Option

REFER TO GRP.

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### 21.4 Verification Concepts

REFER TO GRP.

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### 21.5 Verification Cycle

REFER TO GRP.

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### 21.6 Conducting Verification Activities

Chapter 6 of the O&GP Protocol identifies emission source aggregation options for emissions from O&GP activities. Section 4.4.4 of the GVP, and in particular Table 4.2, provides Verification Bodies some guidance on determining the number of facilities to be visited during the verification process. The Verification Body should treat each Member-defined Oil and Gas Production Installation as equivalent to a single facility when selecting the sample of sites to visit. More specifically, the Verification Body should understand the term “facility” in Table 4.2 of the GVP to refer to either a standard facility (i.e., a single physical premises) or an Oil and Gas Production Installation.

Additional verification guidance for Verification Bodies is available in the Oil and Gas Production addenda to the General Verification Protocol.

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### 21.7 Activities to Be Completed After the Verification Body Reports Its Findings

REFER TO GRP.

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## 21.8 Unverified Emission Reports

REFER TO GRP.

## Chapter 22: Public Emission Reports

### 22.1 Required Public Disclosure

As described in the GRP, your verified annual emission reports are accessible to the public through The Registry's website. Your emissions data will be disclosed at the facility level (or Oil and Gas Production Installation-level) by GHG and emissions category. You may apply to The Registry for an exemption from the public release of your facility-level or production field-level emissions data.

Please refer to the GRP for other information on the required public disclosure of your emissions data.

### 22.2 Confidential Business Information

REFER TO GRP.

## GLOSSARY OF TERMS<sup>78</sup>

These definitions are from the emission factors source documents: GRI GHGCalc, API Compendium, and GRI/EPA "Methane Emissions from the Natural Gas Industry"

Term	Definition
Activity Data Set	An Activity Data Set is what is used to store activity values for a facility. A facility can have more than one Activity Data Set; for example, Activity Data Sets can be defined to represent the following scenarios: <ul style="list-style-type: none"> <li>• Multiple years of a given facility's operations (such as 1990 baseline conditions and current year operations);</li> <li>• Different seasons of operation in a given year (such as summer versus winter operations at a storage facility); or</li> <li>• Different sites within a facility (such as each pipeline in a transmission company or each production field for a production company).</li> </ul>
Activity Data	The activity data of a particular source is a measure of the annual "usage" of that source which can be an equipment count, production rate, or the frequency of an emissions-generating event. It is multiplied by an emission factor, which is an estimate of the emissions per unit "usage" from that source, to obtain the annual emission rate. For example, to estimate combustion emissions from an engine, the emission factor is given in lb/MMhp-hr (in customary U.S. units), and the activity data are in units of MMhp-hr/yr, to give an emission rate of lb/yr.
AGR	Abbreviation for acid gas recovery processes. AGRs remove sulfur compounds and CO <sub>2</sub> from natural gas streams.
Anthropogenic Emissions/Removals	Greenhouse gas emissions and greenhouse gas removals that are the result of human activities, either directly or indirectly through natural processes that have been affected by human activities.
Associated Gas	Natural gas that is in contact with crude oil in the subsurface reservoir. Associated gas is wet gas; that is, it typically contains significant amounts of condensate and/or liquid hydrocarbons. Associated gas occupies a separate portion of the reservoir from dissolved or non-associated gas.
Barrel	One barrel is defined as 42 U.S. gallons.
Barrels of Oil Equivalent (BOE)	The quantity of any fuel necessary to equate on a British Thermal Unit (Btu) basis with a barrel of crude oil. According to the U.S. Internal Revenue Service (IRS), a BOE is any amount of fuel with a Btu content of 5.8 million. According to the California Energy Commission (CEC), one barrel of oil has an energy content of 6 million Btu.
bbl/yr	Abbreviation for barrels per year.
Blanket gas	A gas phase maintained above a liquid in a vessel to protect the liquid against air contamination, to reduce the hazard of detonation, or to pressurize the liquid. The gas source is located outside the vessel.
Blowdown	The venting of natural gas contained inside a pressure vessel, pipeline, compressor, or other equipment for emergency or maintenance purposes. The gas may be vented to the atmosphere or to a control system (e.g. flare or lower pressure gas system (if available)).
Boiler	An indirect-fired water heater that produces steam and/or hot water.
Btu/scf	Abbreviation for British Thermal Units per standard cubic foot.

<sup>78</sup> Note that the terms included in this Glossary are sector-specific terms used in the O&GP Protocol. Other terms applicable to GHG reporting for The Registry are included in the General Reporting Protocol.

Term	Definition
Casinghead Gas	Casinghead gas is natural gas that effuses out of crude oil on the well surface due to the pressure difference between the surface and the reservoir. A casinghead is the top of the casing at the surface of a well, and can be a heavy steel flange bolted to the top of the surface casing as part of the wellhead. The casinghead has a hanger packer that suspends the smaller diameter production string in the well. Casinghead valves are used to relieve gas pressure built up in the casing annular space; this gas is usually either vented or recovered to sales.
Cast Iron Pipeline	Pipelines constructed of cast iron. Cast iron pipes are prone to leakage because of bell and spigot design and frequency of the fittings
Centrifugal Compressor	A compressor that uses blades or impellers to accelerate gas radially, thus imparting kinetic energy to the gas. Centrifugal compressors are common in gas transmission, and are sometimes used in gas gathering. Centrifugal compressors are generally driven by gas turbines.
CH <sub>4</sub>	Methane (CH <sub>4</sub> ) is a naturally occurring greenhouse gas produced through anaerobic decomposition of organic matter in biological systems. CH <sub>4</sub> is also emitted during the production and distribution of natural gas and petroleum, and through incomplete combustion of fossil fuels. CH <sub>4</sub> is the primary component of natural gas.
Chemical Injection Pump	Chemical Injection Pumps are small positive displacement units designed to inject precise amounts of chemicals into process streams to control processing problems and protect equipment. Gas-driven CIPs, which use gas pressure to drive a plunger that drives other fluids (i.e. the chemicals), are commonly used in applications where electricity is not readily available. The motive gas is vented to atmosphere. The vented gas volume depends on the pump size, operating frequency, and supply gas pressure.
Chemical Injection Pump - Diaphragm Pump	Chemical Injection Pumps that use a diaphragm to drive the Chemical Injection Pump plunger.
Chemical Injection Pump - Piston Pump	Chemical Injection Pumps that use a piston to drive the Chemical Injection Pump plunger.
CO <sub>2</sub> -equivalent (CO <sub>2</sub> -e)	The concept of CO <sub>2</sub> -equivalents (CO <sub>2</sub> -e) has been developed to compare the capacity of different greenhouse gases to trap heat relative to a base gas, CO <sub>2</sub> . The CO <sub>2</sub> -e of a particular greenhouse gas is determined by multiplying the concentration of the gas by the global warming potential (GWP) for that gas. The GWP of a greenhouse gas is the ratio of global warming from one mass unit (kilogram or pound) of the greenhouse gas to one mass unit of CO <sub>2</sub> over a period of time. While any period of time can be selected, the GWP for a period of 100 years is recommended by the Intergovernmental Panel on Climate Change (IPCC) and the U.S. Department of Energy [U.S. Department of Energy, 1995]. On this basis, one mass unit of CH <sub>4</sub> released into the atmosphere has the same impact on global warming as 21 mass units of CO <sub>2</sub> (over a 100-year time period). Likewise, one mass unit of N <sub>2</sub> O has the same impact of 310 mass units of CO <sub>2</sub> . Since CO <sub>2</sub> is chosen as the reference gas, the GWP of CO <sub>2</sub> is 1 [U.S. Environmental Protection Agency, 1998].
Combined Cycle	Technology for electricity generation that uses both a combustion turbine and a steam turbine.
Combustion Emissions	Combustion emissions include exhaust from combustion sources such as compressor engines, burners, and flares. Typical combustion products are CO <sub>2</sub> , CO, and NO <sub>x</sub> ; methane is usually emitted as a result of incomplete combustion. Trace levels of N <sub>2</sub> O are also emitted.
Component Counts (Fugitive Emissions)	The number of parts at a site from which fugitive emissions may escape. The EPA has developed six different categories of components: connections, flanges, open-ended lines, pumps, valves, and "others".

<b>Term</b>	<b>Definition</b>
Compressor Blowdown	Compressor blowdowns can be partial or full blowdowns. Partial blowdowns depressurize the compressor to a lower-pressure recovery system or to atmosphere, and leave the compressor at that lower pressure. Full blowdowns depressurize the compressor from full operating pressure to the atmosphere.
Compressor Starts	Gas compressor starters use a small turbine whose blades spin when high-pressure supply gas is introduced to the starter. The supply gas is usually vented to the atmosphere after exiting the starter. Compressed air may power the starter, but natural gas is used more often than air.
Compressor Driver	A mechanical energy source, typically an reciprocating internal combustion engine or turbine that drives a natural gas compressor.
Compressor Station	A compressor station is a site, usually on a gas pipeline, where natural gas is compressed to raise the pressure and keep the gas flowing. In addition to the compressors, compressor stations can have equipment such as separators, pig launchers/receivers, electricity generators, and control equipment.
Condensate	Light hydrocarbons that are gas phase under subsurface well high temperature and pressure conditions and condense to liquid at surface conditions.
Continuous-Bleed Pneumatics	Continuous-bleed pneumatics vent gas both when the device actuates and when it is on standby; thus, the emissions depend on the actuating bleed rate and the stationary bleed rate. This is opposed to intermittent-bleed pneumatics which emit gas only when the device actuates.
Direct Greenhouse Effects	Radiative effects that occur when the gas itself is a greenhouse gas.
Distribution Industry Segment	Distribution facilities receive high pressure gas from transmission pipelines, reduce the pressure, and deliver the gas to residential, commercial, and industrial consumers. This industry segment includes pipelines (mains and services), metering and pressure regulating stations, and customer meters.
Emission Factor	Amount of GHG (e.g. t, lb) released to atmosphere per unit operations (e.g. MMBtu fuel fired, MW-hr electricity produced)
ESD	Abbreviation for emergency shutdown - equipment and pipelines leading to a facility are shut down; the ESD system may then open blowoff valves that depressure the facility to the atmosphere.
Field Gas	Untreated natural gas that has not been sweetened; that is, acid gases such as CO <sub>2</sub> or H <sub>2</sub> S have not been removed. However, if the field gas is to be used as fuel, H <sub>2</sub> O, and sometimes H <sub>2</sub> S, are typically removed. Field gas may also be referred to as raw gas.
Flare	The burning of gas through a pipe, typically as an open flame.
Fugitive Emissions	Fugitive emissions are unintentional leaks of gas from sealed surfaces. See also the fugitive component counts definition.
Gathering Pipeline Water Removal Blowdowns/Pull-backs	Blowdowns on low-pressure (e.g. less than 76 psi) gathering gas system pipelines that have short segments vented briefly (about 10 seconds) to remove accumulated water.
Gathering Pipeline	Pipeline used to gather oil or gas from wellsites or other surface facilities before transfer to a main pipeline, such as an intrastate or interstate pipeline.

Term	Definition
Global Warming Potential	<p>The global warming potential (GWP) is an index used to relate the level atmospheric impact of emissions of various greenhouse gases to a common measure. It describes the relative amount of global warming (or radiative forcing, including both direct and indirect effects) produced by the gas relative to the global warming produced by CO<sub>2</sub>, the reference gas, over a specified period of time. The GWP is used to compare the capacity of different greenhouse gases to trap heat in the atmosphere relative to CO<sub>2</sub>. Global warming potentials are calculated as the following ratio: Radiative Forcing per unit mass of Greenhouse Gas/Radiative Forcing per unit mass CO<sub>2</sub></p> <p>By definition, CO<sub>2</sub> has a GWP of 1, while CH<sub>4</sub> and N<sub>2</sub>O currently have GWPs of 21 and 310, respectively [U.S. Environmental Protection Agency, 1998]. These values are based on a 100-year time period, as recommended by the IPCC.</p>
Glycol Dehydrator	Gas-liquid contacting equipment used to remove water from natural gas using triethylene glycol or ethylene glycol. Natural gas components (e.g. CH <sub>4</sub> ) are absorbed by glycol in small amounts and are emitted when the glycol is regenerated by heating to drive off absorbed water. Some dehyds are equipped with flash tanks and/or emissions controls to reduce hydrocarbon emissions.
Greenhouse Gases (GHG)	A gas that contributes to the natural greenhouse effect. The Kyoto Protocol covers six greenhouse gases (GHGs) produced by human activities: carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. For the purposes of O&GP reporting, CO <sub>2</sub> , CH <sub>4</sub> , and N <sub>2</sub> O are considered.
Heater	Indirectly fired equipment used to heat process materials.
Heat Input	The amount of heat (in MMBtu/hr) supplied by the fuel on an hourly basis, on a higher heating value basis.
Heat Rate	A measure (in Btu/hp-hr) of a compressor driver's fuel efficiency and is calculated as Fuel heat input divided by equipment power output. Calculated by using the lower heating value of the fuel.
Heavy Crude Oil	API designates heavy crude oil as having an API gravity of less than 20°. To convert from specific gravity to API gravity, use: °API = [141.5 / (specific gravity) ] – 131.5
Heavy Duty Truck	A truck with a Gross Vehicle Weight greater than 8,500 pounds.
Horsepower	Units of mechanical power.
hp	Abbreviation for horsepower.
hp-hr	Abbreviation for horsepower-hour.
Hydroelectric Electric Technology	Technology for electricity generation that uses the natural power of running water in streams, rivers, and lakes.
ICE	Abbreviation for (reciprocating) internal combustion engine
Incinerator	A combustion device used to oxidize waste gases or other waste materials.
Indirect Emissions	Indirect emissions refer to those due to purchased electricity consumption; that is, electricity generated at an off-site power plant. By including emissions from electric power generation in the overall facility emissions estimate, companies can take credit for greenhouse gas reductions due to using more energy-efficient processes.
Indirect Greenhouse Effects	Radiative forcing effects occur when chemical transformation of the original gas produces a greenhouse gas, or when a gas influences the atmospheric lifetimes of other gases.
Intermittent-Bleed Pneumatics	Intermittent-bleed pneumatics are devices that emit gas only when the device actuates. This is opposed to continuous-bleed pneumatics, which vent gas both when the device actuates and when it is on standby. Pneumatic Displacement Valve Operators and Turbine Valve Operators are intermittent bleed valve operators.

Term	Definition
"Junked" Vehicle	Vehicles that were completely removed from service or "junked" (no longer operating). Does not include vehicles that were sold for reuse.
Kimray Pump	A positive displacement, gas-assisted pump commonly used in glycol dehydration units that uses gas from a glycol absorber to provide the motive energy for the pump. With these types of pumps, some additional gas is sent to the glycol regenerator. Depending on the glycol dehydrator configuration (e.g. use of a flash tank and/or combustion control for the regenerator emission), all or some of the pump gas will be vented to atmosphere. Kimray is actually a brand name, but the term is used here to indicate any type of pump where dehydrator gas is used to operate the pump.
Large Gathering Compressors	Large gathering compressors are those of sufficient size and horsepower (typically more than three stages) to be in a station setting, much like the stations used in gas transmission. This is opposed to small gathering compressors that may simply be on a pad at the wellsite. The large vs. small distinction is important because compressors in large stations tend to have separate vent lines and larger suction headers, discharge headers, and block valves, which lead to greater fugitive emissions. In the 1996 GRI/EPA Study, large gathering compressor stations were defined as those reported to United States Federal Energy Regulatory Commission (FERC) that had at least 16 stages of compression (five compressors per station and an average of 3.3 stages per compressor).
LB	Abbreviation for lean burn.
Leak Detection and Repair (LDAR) Program	This is a maintenance program that involves regularly scheduled leak detection of an entire facility, followed by a repair effort for the identified leaks. The number of leaks is tracked and the total leak rate may also be tracked. Another name commonly used for the LDAR program is Inspection and Maintenance (I&M).
Lean-Burn IC Engine	A lean-burn IC engine has an air-to-fuel ratio that is greater than stoichiometric and cannot be adjusted to operate with an exhaust O <sub>2</sub> concentration of less than 1 percent. Air-to-fuel mass ratios typically range between 20:1 and 60:1. A lean-burn engine is typically available in two designs: direct-injected and premixed.
Light Crude Oil	API designates light crude oil as having an API gravity of greater than 20°. To convert from specific gravity to API gravity, use: °API = [141.5 / (specific gravity)] - 131.5
Light Duty Truck	A truck or large scale SUV with a Gross Vehicle Weight less than or equal to 8,500 pounds. The average miles per gallon for gasoline light duty trucks is 14 mpg and the average miles per gallon for diesel light duty trucks is 15 mpg.
Meter	A device used to measure volumes or rates of fluids (liquid or gas).
MMBtu	Abbreviation for million British thermal units.
MMhp-hr	Abbreviation for million horsepower hours.
MMscf	Abbreviation for million standard cubic feet per year.
MMscf/yr	Abbreviation for million standard cubic feet. Standard conditions are 60°F and 1 atmosphere.
MMscfd	Abbreviation for million standard cubic feet per day, a commonly used measure of natural gas flow. Standard conditions are 60°F and 1 atmosphere.
Mscf	Abbreviation for thousand standard cubic feet at 60°F and 1 atmosphere.
MW	Megawatt.
Natural Gas	Pipeline quality gas that has had processing for sour gases and heavy hydrocarbons removal.
Nitrous Oxide (N <sub>2</sub> O)	Nitrous oxide is a naturally occurring greenhouse gas. N <sub>2</sub> O is also formed during fossil fuel combustion. N <sub>2</sub> O emission factors are sometimes calculated by assuming that 1.5 percent of NO <sub>x</sub> emissions are N <sub>2</sub> O.

<b>Term</b>	<b>Definition</b>
Non-associated Gas	Gas dissolved in crude oil that is released at well surface conditions (lower pressure and temperature)
NOx	Oxides of nitrogen (usually NO and NO <sub>2</sub> ) that are formed during fossil fuel combustion, lightning, soil microbial activity, biomass burning, and, in the stratosphere, from nitrous oxide. Nitrogen oxides are considered ozone precursors and have an indirect effect on climate change because of their role in promoting the formation of tropospheric ozone.
Other Direct Vented	Vented emissions not accounted by emissions sources not otherwise listed.
Pipeline Blowdown	Venting of gas from a pressurized pipeline, usually to the atmosphere, for repairs, to remove old pipelines from service, or to put new pipelines in service.
Pipeline Dig-In	A pipeline dig-in refers to unintentional impact with a buried pipeline, usually caused by excavation activity in the pipeline right-of-way. The dig-in may cause a pipeline scrape, puncture, or rupture and gas release.
Piston Displacement Valve Operators	Valve operators that use pneumatic force (gas pressure) to move a piston. The piston acts on an arm or level that rotates the valve stem. Gas is supplied to one side of the piston and exhausted from the other, so that the arm is moved in either direction, opening and closing the valve.
Plastic Pipeline	The plastic pipeline category includes any pipe made of a non-steel material. A common pipeline plastic is polyvinylchloride (PVC), although others are available. Plastic pipe is most commonly used in low-pressure applications, such as gas distribution or low-pressure gathering systems.
Platform ESD	An emergency shut-down (ESD) on an offshore platform.
Pneumatic Displacement Valve Operators	These are valve operators that use pneumatic force (gas pressure) to move a valve actuator element in one direction. The pneumatic force is either applied directly to the actuator element or applied to an oil so that hydraulic force moves the actuator. The actuator element is "displaced" from its original position by the pneumatic or hydraulic force. In either case, gas is discharged when the valve is actuated. Displacement operators in the gas industry are of two basic types: 1.) rotary vane; and 2.) piston. A common application is as an isolation valve operator. These are intermittent bleed pneumatic devices.
Processing Industry Segment	Processing facilities are those that process natural gas to recover natural gas liquids and remove undesirable substances such as hydrogen sulfide. A gas processing facility is defined as a separate, stand-alone plant that handles entire field volumes for multiple processing purposes, such as dehydration, compression, hydrocarbon liquid recovery, acid gas rejection, etc. While some gas processing steps can be performed at individual onshore wellsites (dehydration and H <sub>2</sub> S removal, for example), these smaller operations are not included in the definition of gas processing.
Production Industry Segment	Facilities in the production segment are those that gather natural gas or oil from production wells. These facilities may include separators, heaters, tanks, dehydrators, amine units, compressors, and gathering pipelines.
Protected Steel	Steel pipeline - bare and coated - that does have cathodic protection.
PRV	Pressure Relief Valve. PRVs protect equipment (e.g. vessel, pipeline) from rupturing due to high pressure. If emergency conditions occur, where internal pressures exceed the vessel's design pressure, the valve lifts and allows gas flow out of the vessel.
psig	Abbreviation for pounds per square inch gauge.
Purge	Purge is the process of clearing air from equipment by displacing it with natural gas; in the process, some purge gas is emitted to the atmosphere is evacuated from the equipment.
Radiative Forcing	A measure of changes in the energy transfers among space, the atmosphere, land, and the oceans.

Term	Definition
Raw Gas	Untreated natural gas that has not been sweetened; that is, acid gases such as CO <sub>2</sub> or H <sub>2</sub> S have not been removed. Raw gas also typically has not had water, inerts, or liquid hydrocarbons removed. This may also be referred to as field gas; however, H <sub>2</sub> O, and sometimes H <sub>2</sub> S, are removed before the field gas is used as fuel.
RB	Abbreviation for rich burn.
Reciprocating Compressor	A compressor that uses pistons moving back and forth (reciprocating) in cylinders to compress natural gas. These compressors are typically driven by reciprocating internal combustion engines.
Renewables	Renewables are sources for electricity generation that are not completely consumed during the generation process. Wind power and solar power are two examples. Renewable sources generally have insignificant greenhouse gas emissions relative to other electricity generation technologies.
Residual Fuel Oil	Heavier oils that remain after the distillate fuel oils and hydrocarbons are distilled away in refinery operations and conform to ASTM Specifications D396. Included are No. 5, a residual fuel oil of medium viscosity; Navy Special, for use in steam powered vessels in government services and in shore power plants. And No. 6., which includes Bunker C fuel oil and is used for commercial and industrial heating, electricity heating, and to power ships.
Rich-Burn IC Engine	A rich-burn IC engine operates with an air-to-fuel ratio that is near stoichiometric, or fuel-rich, and has an exhaust O <sub>2</sub> concentration ranging from zero to five percent. Air-to-fuel mass ratios typically range between 16:1 and 20:1. Rich-burn engines include all naturally aspirated and non-scavenged, turbocharged 4-stroke engine models.
Rotary Vane Pneumatic/Hydraulic Displacement Operators	Rotary vane pneumatic/hydraulic displacement operators use natural gas to force a fixed amount of oil from one pressure bottle to another. The oil moves through the vane operator, delivering hydraulic force to the vane, and moving it and the attached valve stem one quarter turn. The oil moving through the bottle forces gas in the top of the receiving pressure bottle to vent to the atmosphere.
scf	An abbreviation for standard cubic foot of gas. Standard conditions are 60°F and 1 atmosphere.
scm	An abbreviation for standard cubic meter of gas. Standard conditions are 15°C (60°F) and 101.3 kPa (1 atmosphere).
Separator	A vessel used to separate oil, gas, and water from the total fluid stream produced by a well. Separators can be either horizontal or vertical.
Simple Cycle	A gas turbine that produces electricity without heat recovery or steam generation.
Small Gathering Compressors	Compressors that are not of sufficient size and horsepower (typically three or fewer stages) to be in a separate station setting. Small compressors may individually have large horsepower, but are typically reciprocating engines on a pad by themselves at a wellsite or central facility. The large vs. small compressor distinction is important because large compressors tend to have separate vent lines and larger suction headers, discharge headers, and block valves, which lead to greater fugitive emissions. In the 1996 GRI/EPA Study, large gathering compressor stations were defined as those reported to United States Federal Energy Regulatory Commission (FERC) that had at least 16 stages of compression (five compressors per station and an average of 3.3 stages per compressor).
Sour Gas	Production natural gas that contains hydrogen sulfide and significant quantities of carbon dioxide. H <sub>2</sub> S and CO <sub>2</sub> are often referred to as "sour gases".
Standard Conditions	Standard conditions used to convert between mass and volumetric gas flow rates are 60°F and 1 atmosphere. This corresponds to 379 scf/lb-mol of gas.
Steam Turbine	A turbine that produces electricity using steam as the driving fluid.

<b>Term</b>	<b>Definition</b>
Sweet Gas	Natural gas that does not contain hydrogen sulfide (H <sub>2</sub> S) or significant quantities of carbon dioxide (CO <sub>2</sub> ).
Tanks Flashing Losses	The vaporization of volatile hydrocarbons when pressurized oil and condensate are dumped into a lower pressure (atmospheric) storage tank.
Total Dissolved Solids (TDS)	Inorganic salts (principally calcium, magnesium, potassium, sodium, bicarbonates, chlorides and sulfates) and some small amounts of organic matter that is dissolved in water.
Turbine	A turbine, also called a gas turbine or combustion turbine, is a rotary engine that extracts energy from a flow of hot gas produced by combustion of gas in a stream of compressed air.
Turbine Valve Operators	Turbine valve operators release gas to the atmosphere across a small turbine similar to a gas starter turbine for a reciprocating compressor. The gas spins the blades, and the turbine shaft then turns gears that move the valve stem. A common application is as an isolation valve operator. These are intermittent bleed pneumatic devices.
Unprotected Steel	Steel pipeline - bare and coated - that does not have cathodic protection.
Vented Emissions	Vented emissions are direct releases to the atmosphere resulting from equipment design (dehydrator still vents, for example), regular process operations, maintenance activities, or emergency releases.
Vented Gas Event	A blowdown or purge of equipment for maintenance or emergency purposes that releases gas.
Vessel	Equipment such as separators, dehydrators, and in-line heaters that contain process fluids (liquids and gas) under pressure.
Weathered Crude	Crude that has reached atmospheric pressure so that the volatile CH <sub>4</sub> /CO <sub>2</sub> has flashed off. The crude oil vapors in weathered crude contain very little, if any, CH <sub>4</sub> or CO <sub>2</sub> .
Well (Gas) Completion	After well drilling operations are completed, the gas flow rate must be measured to size the production equipment. To measure the gas flow rate, the gas from the well is routed through a meter and then vented to atmosphere or flared.
Well (Gas) Unloading/Cleanup	Maintenance activity. Operators may routinely open some low flow rate gas wells to the atmosphere to remove salt water accumulation in the wellbore. Low-pressure natural gas wells can accumulate salt water and other fluids in the wellbore if the gas flow rate is not sufficient to lift out the free liquid. The well is isolated from the gathering pipeline and opened to a surface tank or pit. With no backpressure from the pipeline, gas flows at a higher rate and lifts out the water. The gas is released directly to the atmosphere.
Well Workover	Well workovers pull the tubing from the well to repair corrosion or other downhole equipment problems. If the well has positive pressure at the surface, the well is "killed" first by replacing the gas and oil in the column with (heavier) water or mud, thus over-balancing the formation and stopping all oil and gas flow. A small amount of gas is released as the tubing is removed from the open surface casing.