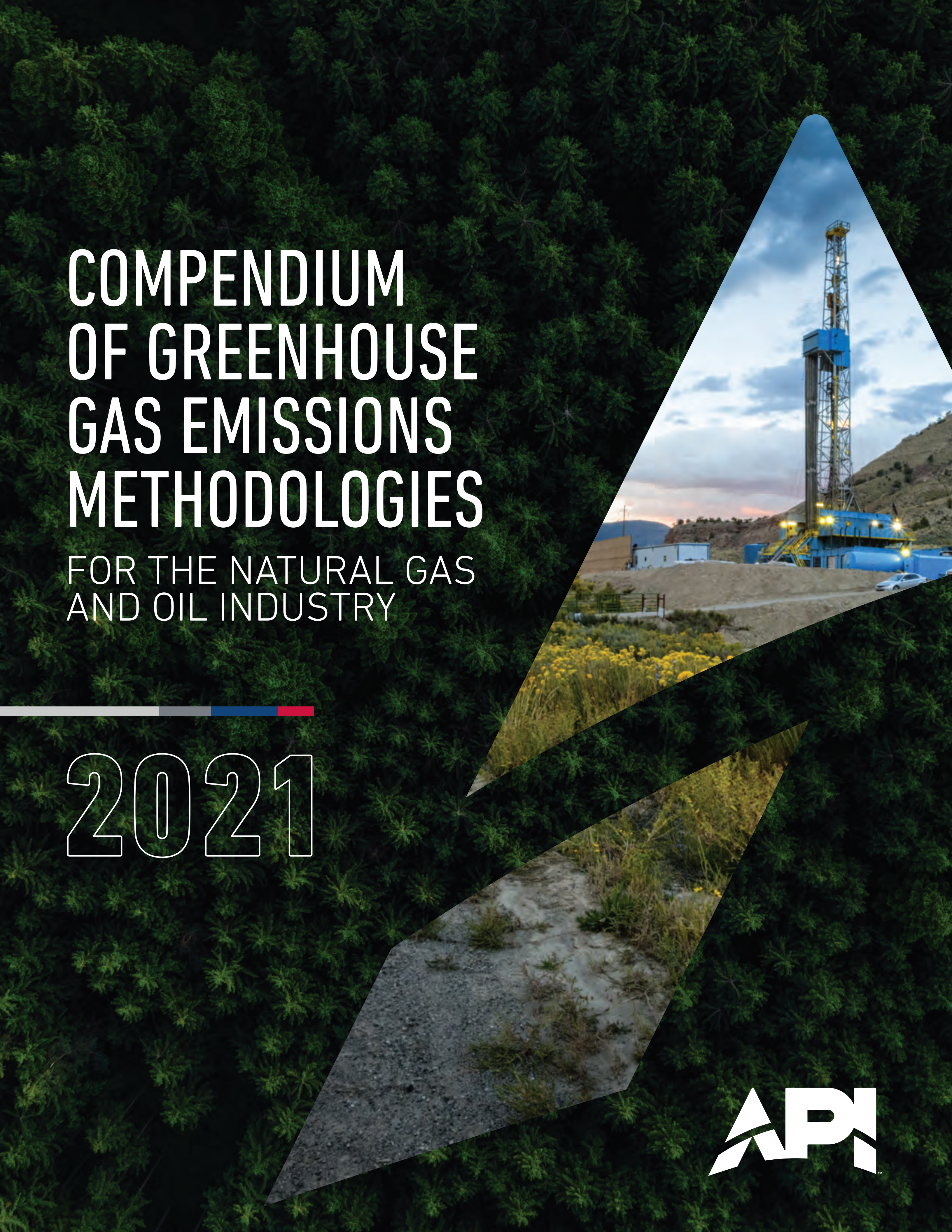

COMPENDIUM OF GREENHOUSE GAS EMISSIONS METHODOLOGIES

FOR THE NATURAL GAS AND OIL INDUSTRY

2021

COMPENDIUM OF GREENHOUSE GAS EMISSIONS METHODOLOGIES FOR THE NATURAL GAS AND OIL INDUSTRY

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This compendium was prepared by:

Lisa Campbell
Julia Toolen
Denise Grubert
Gary Napp

ERM
4140 Parklake Avenue, Suite 110
Raleigh, NC 27612

Developed for:

American Petroleum Institute
200 Massachusetts Ave. NW
Washington, DC 20001

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PREFACE

Dear Reader:

Every day, the natural gas and oil industry is working to reduce emissions and build a lower-carbon future while continuing to meet rising global energy demand. Experts agree that API's *Compendium of Greenhouse Gas Emissions Methodologies for the Natural Gas and Oil Industry* serves as a key resource for companies striving to meet that dual challenge in ways that yield tangible results. As described in API's *Climate Action Framework*, the *Compendium* supports timely and accurate estimation and reporting of greenhouse gas (GHG) emissions. It is also the basis for industry transparency going forward.

This new edition of the *Compendium*, the first update since 2009, details methodologies for natural gas and oil industry segments to consistently estimate direct GHG emissions over the entire value chain. The work reflects the evolution of GHG calculation and incorporates what has been learned in this field over the past 12 years. For the first time, the *Compendium* includes expanded methodologies for liquefied natural gas, as well as carbon capture, use, and storage. Taken together with API's safety and sustainability standard setting and performance initiatives for the industry worldwide, the *Compendium* is another tool to measure and drive safety, health, and environmental progress across its operations, while meeting global demand for affordable, reliable and cleaner energy.

This effort is the product of collaboration among API member companies and other industry stakeholders. More broadly, this important update reflects our member companies' experience in emissions reporting and their continued commitment to transparency and further emission reductions. It's an invaluable tool for data that is foundational to the industry's ongoing engagement with EPA, as well as with other regulators around the world, including those in Canada, Mexico and Australia – which cite the *Compendium* in their official regulations.

Honing and enacting impactful energy and climate policy represents the opportunity of our time, requiring new technologies, a professional and innovative workforce, and a commitment to do things better, cleaner and safer – for communities and the environment. This comprehensive work establishes a foundation by which the industry can demonstrate to a wider public audience that, based on the best available emissions data, this essential American industry is crafting a range of meaningful actions to protect the environment while providing affordable energy.

All the best,

Mike Sommers
API President and CEO

Table of Contents

Preface

List of Tables

List of Figures

Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Natural Gas and Oil Industry

Section 1 - Introduction

November 2021

Table of Contents

List of Tables

1.0 INTRODUCTION

The American Petroleum Institute (API) and many of its member companies are implementing action plans for addressing greenhouse gas (GHG) concerns and policy issues. Concurrently, local, regional, national and international bodies are developing or revising their guidance on estimating, reporting, and verifying GHG emissions. This document is a compendium of currently recognized methods and provides details for all oil and natural gas industry segments to enhance consistency in emissions estimation.

This API *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry* (referred to as the "API *Compendium*") aims to accomplish the following goals:

- Assemble an expansive collection of relevant emission factors and methodologies for estimating GHG emissions, based on currently available public documents;
- Outline detailed procedures for conversions between different measurement unit systems, with particular emphasis on implementation of oil and natural gas industry standards;
- Provide descriptions of the multitude of oil and natural gas industry operations – in its various segments – and the associated GHG emissions sources that should be considered; and,
- Develop emission inventory examples – based on selected facilities from various oil and natural gas industry operations – to demonstrate the broad applicability of the methodologies.

The overall objective of this document is to promote the use of consistent, standardized methodologies for estimating GHG emissions from oil and natural gas industry operations[1]. As a result, this API *Compendium* recognizes calculation techniques and emission factors for estimating GHG emissions for oil and natural gas industry operations. These techniques seek to cover the calculation or estimation of emissions from the full range of industry operations – from exploration and production through refining, to the marketing and distribution of products.

The API *Compendium* presents and illustrates the use of emission estimation methods for carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6) for all common emission sources, including combustion, venting, and fugitive sources. Decision trees are provided to guide the user in selecting a calculation or estimation technique that is based on considerations of materiality, data availability, and accuracy. **METHODOLOGIES REQUIRED BY REGULATIONS TAKE PRECEDENCE OVER THE OPTIONS PROVIDED IN THE DECISION TREES.**

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[1] Although the API *Compendium* was derived for oil and natural gas industry operations, the methodologies presented in the API *Compendium* can be used by other industries, particularly those that utilize fossil fuels.

1.1 Background

The API *Compendium* was first released in April 2001. Since that time, comments on the API *Compendium* have been received through several mechanisms, including industry conferences, workshops, and focused outreach to other protocol development organizations, particularly those used by the oil and natural gas industry in other regions of the world. Through collaboration with other industry-related protocol development organizations, an updated API *Compendium* was published in 2009 (API, 2009). The API *Compendium* is a foundational document to estimating GHG emissions from the oil and natural gas industry and is applied in both operational and regulatory settings worldwide. Regulatory bodies in countries around the world with significant oil and natural gas industry presence, including Australia, Canada, Mexico, and Singapore, rely on the API *Compendium* to support measurement and reporting guidelines. The preparation of this 4th release of the API *Compendium* applied a similar approach to ensure a collaborative effort across the global oil and natural gas industry and represents industry best practices for estimating GHG emissions.

In the intervening years between the publication of the 3rd release and this release, a parallel effort was initiated to promote consistent, credible, and reliable GHG accounting and reporting practices for the oil and natural gas industry. A team of oil and natural gas industry representatives led by the International Petroleum Industry Environmental Conservation Association (IPIECA), the Association of Oil and Gas Producers (OGP) and API, issued a second edition of the *Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions* (referred to as the *Guidelines*) in 2011 (IPIECA, et al., 2011). This effort recognized the need to update the original publication of the *Guidelines* to reflect changing practices and to continue to build upon other existing protocols for estimating GHG emissions by providing information to address the unique operational arrangements of the oil and natural gas industry.

In 2015, IPIECA and API published an update to the 2009 document *Addressing Uncertainty in Oil & Natural Gas Industry Greenhouse Gas Inventories: Technical Considerations and Calculation Methods* (referred to here as the *Uncertainty Document*), which was initially developed from an international workshop convened to augment existing industry guidance and provide technically valid approaches applicable for use by the global oil and natural gas industry to improve GHG emissions estimation robustness and data quality (API, IPIECA, 2015).

Additionally, API and its member companies developed the *API Template for GHG Reporting* (referred to here as the *API Template*) to facilitate transparent climate-related reporting that allows like-for-like GHG emissions performance comparison (API, 2021). Consistent and comparable climate-related reporting has grown in importance for a variety of stakeholders, including financial sector, industry customers, and policymakers. The *API Template* includes a set of GHG indicators that API member companies have agreed represents the core, or foundational, indicators for individual company reporting of company-wide GHG emissions and GHG mitigation activities. This template builds on existing climate-related reporting frameworks by providing a core set of GHG indicators with standardized names, units, and definitions of the reporting boundaries, including across the value chain of the oil and natural gas industry.

More broadly, IPIECA, API and the International Association of Oil & Gas Producers (IOGP) have continued to update the *Sustainability Reporting Guidance for the Oil and Gas Industry* (referred to here as the *Sustainability Guidance*) since its initial publication in 2005, with the 4th publication in 2020 (IPIECA, IOGP, API, 2020). This framework is intended to help companies shape the structure and content of their sustainability reporting, including but not limited to greenhouse gas emissions.

The API *Compendium*, *Guidelines*, *API Template*, *Sustainability Guidance* and *Uncertainty Document* are complementary; where the API *Compendium* focuses on GHG emission estimation methodologies for industry sources (how to calculate emissions), the *Guidelines* primarily address GHG accounting and reporting questions faced by the industry (how to report emissions), the *API Template* seeks to standardize and provide indicators for reporting across the industry (how to report and characterize emissions), the *Sustainability Guidance* provides structure and content for broader sustainability reporting (how to report emissions and more), and the *Uncertainty Document* addresses the confidence intervals for the inventory results. Combined, the API *Compendium*, *Guidelines*, *API Template*, *Sustainability Guidance* and *Uncertainty Document* provide comprehensive guidance for the estimation, accounting, reporting, and characterization of oil and natural gas industry GHG emissions.

1.2 Document Overview

The API *Compendium* is neither a standard nor a recommended practice for the development of emissions inventories. Rather, as the name implies, it represents a compilation of commonly used GHG emission estimation methodologies.

Methodologies outlined in this API *Compendium* can be used to guide the estimation of GHG emissions for individual projects, entire facilities, or company-wide inventories. The purpose of the GHG analysis, as well as the availability of data, will generally determine the level of detail and the estimation approach to be selected. The methodologies presented here address the estimation of all six GHG species or families of gases (CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6) from oil and natural gas industry operations. This should not imply that emissions of all these GHG compounds are necessarily significant for all emission sources or industry operations, as their presence varies highly and depends on source design and operational practice. The emission estimation approaches presented are believed to be practical for all segments of the oil and natural gas industry. The operations and facilities addressed range from the well-head to retail outlets, including exploration and production (E&P), refining, marine vessels, pipelines, bulk distribution, other transportation, and retail marketing. The methods presented in this API *Compendium* pertain only to emissions from operations and not those that might be attributable to product use. Industry data provided throughout this document list the carbon content fraction for typical fuels in commerce, but no attempt is made to account for hypothetical efficiencies associated with product use.

Transparency is a key issue in developing GHG inventory estimates. It is strongly recommended that any estimation approach used should be well annotated, with all input information recorded and careful documentation of the underlying conditions and assumptions. This level of detail is necessary to track and compare GHG emission information over time and to allow for future revisions as new information becomes available. Moreover, the dynamic nature of oil and natural gas industry operations, along with changes in estimation procedures, necessitate good narrative descriptions of included operations and equipment, in addition to careful calculations and knowledge of operating procedures.

It is also important to note that emission results can differ, in some cases significantly, depending on the specific approach(es) used to estimate emissions. The documents referenced above (Section 1.1) provide guidance for selecting appropriate estimation techniques based on the intended use of the inventory data and the availability of required input data. Beyond regulatory requirements, the use of the information presented in this document is left to the discretion of the user.

1.3 Organization

Section 2 of this API *Compendium* provides a description of the various industry segments and their interrelation. It sets out a common classification for all devices in the various segments and includes listings of operations and sources that need to be assessed for their GHG emissions, with a focus on CO_2, CH_4, and N_2O emissions because these are the most relevant to oil and natural gas industry operations. The equipment classification system described in Section 2 is summarized in Table 1-1 and includes the major emission categories, with a representative list of devices that might fall into each of these categories.

Indirect emissions are emissions that are a consequence of activities of the reporting company, but which result from sources owned or controlled by another party. All other sources identified in Table 1-1 are considered direct emissions, which result from sources owned or controlled by the reporting company. For transparency, if reported, indirect emissions should be reported separately from direct emissions. More information on the differences and reporting of direct and indirect emissions can be found in the *Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions* (IPIECA, et al., 2011).

Table 1-1. Proposed Source Classification Approach[a]

Category	Principal Sources Include:
Direct Emissions	
Combustion Sources	
Stationary Devices	Boilers, heaters, furnaces, reciprocating internal combustion engines and turbines, flares, incinerators, and thermal/catalytic oxidizers
Mobile Sources	Barges, ships, railcars, and trucks for material transport; planes/helicopters and other company vehicles for personnel transport; forklifts, all terrain vehicles, construction equipment, and other off-road mobile equipment
Process Emissions and Vented Sources[b,c]	
Process Emissions	Hydrogen plants, amine units, glycol dehydrators, fluid catalytic cracking unit and reformer regeneration, and flexi-coker coke burn
Other Venting	Crude oil, condensate, and oil and natural gas product storage tanks, gas-blanketed water and chemical tanks, underground drain tanks, gas-driven pneumatic devices, gas samplers, chemical injection pumps, exploratory drilling, loading/ballasting/transit, and loading racks
Maintenance/Turnaround	Decoking of furnace tubes, well unloading, vessel and gas compressor depressurizing, compressor starts, gas sampling, and pipeline blowdowns
Non-Routine Activities	Pressure relief valves, PCVs, fuel supply unloading valves, and emergency shut-down devices
Fugitive Sources[d]	
Fugitive Emissions	Valves, flanges, connectors, pumps, compressor seal leaks, and catadyne heaters
Other Non-Point Sources	Wastewater treatment and surface impoundments
Indirect Emissions	
Electricity	Off-site generation of electricity for on-site power
Steam/Heat	Off-site generation of hot water and steam for on-site heat
District Cooling	Off-site gaseous pressurization (compression) for on-site cooling

[a] Note that this API *Compendium* uses terms (e.g., "routine," "maintenance," "point source") that may have both a commonplace, non-legal meaning, and a specific, legal meaning. The API *Compendium* uses the commonplace, non-legal meanings for these terms and does not use them in their legal sense.

[b] Vented emissions are intentional or designed into the process or technology to occur during normal operations.

[c] The above categories of emissions are broad listings intended to give an indication of the emission sources in the oil and natural gas industry. Note that some regulatory and/or voluntary reporting programs classify the categories differently, including what sources are included under the vented, process, and fugitive categories.

[d] Fugitive emissions can be individually found and "fixed" to make the emissions "near zero."

Section 3 presents detailed technical considerations and suggestions for developing a consistent emissions estimate. To allow for global use of the estimation approaches, this section of the API *Compendium* contains conversion factors, standard gas conditions, and fuel properties for fuels typically found in the oil and natural gas industry. It also introduces key statistical calculation methods for assessing uncertainty ranges for GHG emissions from applicable sources. A discussion on emission factor quality and inventory accuracy is also provided in Section 3.

Sections 4, 5, 6, and 7 provide the compiled calculation methodologies for direct emissions from: combustion devices, waste gas disposal, process and operational venting, and fugitive emission sources, respectively. Each section presents the details of various estimation approaches for each source, device, or operation and includes example calculations. The estimation approaches are presented by either equipment or fuel type, and by operational practices. These sections strive to balance the need to make the computational tasks as simple as possible while retaining sufficient accuracy in the final inventory. To accomplish this, the methodology provides options for relying on generic estimation methods – if applicable – such that specific knowledge of every equipment detail may not be essential. For example, many of the combustion device estimation approaches will be the same regardless of the industry segment in which they occur. However, most of the process vents are specific to an industry segment and reflect a specific operational practice for that part of the oil and natural gas industry. Examples are provided throughout the API *Compendium* to demonstrate calculation methodologies. Examples may be used multiple times throughout the document and are intended to be as realistic as possible.

Section 8 presents methods that are applicable for estimating indirect GHG emissions from sources that provide power, heat and steam, and cooling. In the case of indirect emissions from power generating activities, the methods rely on average EFs based on national compilation, such as eGrid[2] in the US and the International Energy Agency (IEA) for sources out of the US. The section also describes different methods, recommended by diverse programs, for the allocation of GHG emissions between the power and heat/steam generation aspects of Combined Heat and Power (CHP) installations.

Appendices A, B, and C provide additional calculation methodologies and further details for emission sources covered in Sections 4, 6, and 7, respectively. Appendix D provides fuel speciation details to support combustion and non-combustion emission estimation. Appendix E contains an analysis of fugitive CH_4 emissions from refinery operations. Appendix F contains an alternative method for calculating emissions from hydraulic fracturing operations.

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[2] EPA maintains a database with information from power plants and electricity generators. The database is available at the following website: http://www.epa.gov/cleanenergy/egrid/index.htm .

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Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Natural Gas and Oil Industry

Section 2 – Industry Description

November 2021

Table of Contents

List of Tables

List of Figures

2.0 INDUSTRY DESCRIPTION

This section presents a description of the oil and gas industry and its segments to give some perspective on the potential sources of GHG emissions. Figure 2-1 presents a graphical overview of the primary industry segments along the operations chain. The following subsections describe those industry segments and operations, with the associated GHG emission sources in more detail.

Note: The primary GHGs of interest (CO_2, CH_4, and N_2O) are addressed throughout this document. Other GHGs, such as fluorinated gases, may only be addressed for those sources for which such emissions are considered material.

2.1 Overview

For the purposes of this document, the oil and gas industry includes all direct activities related to exploration, production, gathering, processing, transmissions, storage, refining, transportation and marketing of natural gas, crude oil and associated products. Figure 2-1 shows a graphical overview of the industry. The key industry segments along the operations chain include:

- Oil and Gas Exploration;
- Oil and Gas Production;
- Oil and Gas Gathering and Boosting;
- Natural Gas Processing;
- Natural Gas Transmission and Storage;
- Liquefied Natural Gas (LNG) Operations;
- Natural Gas Distribution;
- Enhanced Oil Recovery (EOR);
- Crude Oil Transportation
- Refining; and
- Retail and marketing of petroleum liquids.

These segments are the direct activities within the oil and gas industry that have the potential to emit GHG. Integrated petroleum companies may also have operations associated with energy generation (electricity, heat/steam generation, or cooling), mining and minerals, petrochemical manufacturing, and/or carbon capture and geological storage.

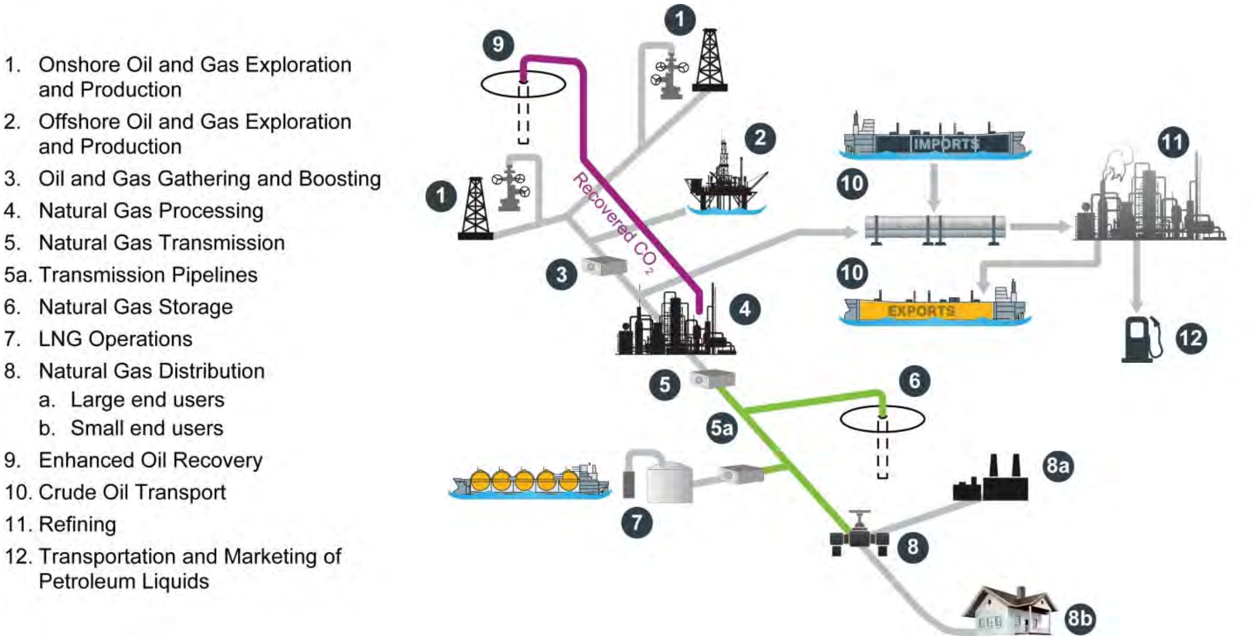

Figure 2-1. Oil and Gas Industry Operations Flowchart and GHG Emissions Sources

In addition, petroleum processes may also purchase electric power or heat/steam. However, the combustion emissions from these externally generated sources are considered an indirect contributor of GHG emissions. Indirect GHG emissions from external power and heat/steam generation are reported separately from the direct petroleum sector emissions. Additional guidance on accounting for indirect emissions is provided in Sections 3.2.2 and Section 7 of the 2nd Edition of the *Petroleum Industry Guidelines for Reporting GHG Emissions* (IPIECA, et. al, 2011).

Tables 2-1 through 2-16 present expansive checklists of potential GHG emission sources in each primary industry sector, as well as other "specialty" operations that may be part of a petroleum company's portfolio. These tables also include an indication of whether each source is likely to emit CO_2, N_2O, and/or CH_4 and reference sections of this document where further details on emission factors and emission calculation methodologies are provided. The sources listed in Tables 2-1 through 2-16 may potentially be located at a facility; however, individual facilities vary and some sources listed in the tables may not be present at all facilities.

Tables 2-1 through 2-16 also indicate which specific sources of emissions were considered in preparing this document. The "X" is used to designate which GHG species may be emitted from the source identified, for which estimation methodologies are provided in this API *Compendium* document. An "*" is listed for some sources of CO_2 emissions in the production segment and CH_4 emissions associated with CCS processes. This is used to note potential sources of CO_2 emissions for those production streams rich in CO_2, such as associated gas from enhanced oil recovery or where CH_4 may be present in gas streams associated with CCS. An approach is provided for these sources, but the significance of CO_2 emissions depends on the CO_2 concentration and the source-specific emission rate.

In addition, SF_6, PFCs, and HFCs are also greenhouse gases with global warming potentials several hundred to several thousand times larger than that of CO_2. Sulfur hexafluoride may be used by oil and gas companies that operate electric transmission equipment or as a tracer gas to detect pipeline leaks. As a result of using substitutes for ozone-depleting substances (ODSs), air conditioning (mobile and stationary), refrigeration, and fire suppression equipment are potential sources of HFC and PFC emissions. The API *Compendium* provides estimation methods for non-CO_2 emissions, where applicable, though this should not imply that these emissions are necessarily significant.

The diversity of operations associated with the oil and gas industry presents a challenge in determining the relative contribution of the many different emission sources. The *Guidelines* document provides some considerations to help the reader use available time and resources effectively (IPIECA, et. al., 2011).

2.2 Oil & Gas Industry Segments Descriptions

In this API *Compendium*, the oil and gas industry is divided into the following categories for the purpose of describing applicable emission estimation methodologies:

- Oil and Gas Exploration;
- Oil and Gas production;
- Oil and Gas Gathering and Boosting;
- Natural Gas processing;
- Natural Gas Transmission and Storage
- Liquefied Natural Gas (LNG) Operations
- Natural gas distribution;
- Enhanced Oil Recovery (EOR);
- Crude Oil Transportation
- Refining;
- Retail and marketing of Petroleum liquids

For the purpose of this document, the scope of a company's inventory may include any or all of these activities. The following subsections describe emission sources associated with each of these categories of operations.

2.2.1 Oil and Gas Exploration

This segment includes the activities and associated emissions for exploration of oil and gas that may be located in underground reservoirs either onshore or offshore. Exploration primarily involves various geological and geophysical surveys and tests, followed by exploratory drilling in likely areas.

Exploration encompasses well drilling, testing, and completions. The predominant sources of emissions from exploration are hydraulically fractured oil and gas well completions and well testing. Other sources include well completions without hydraulic fracturing, and well drilling. The primary emission sources from exploration are the exhaust from internal combustion (IC) engines used in drilling operations; the venting or flaring of gas associated with well testing or completions; and mobile source emissions associated with equipment used at the well site and to transport personnel and equipment to/from the site.

Well completions means the process that allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and test the reservoir flow characteristics, steps which may vent produced gas to the atmosphere via an open pit or tank. Well completion also involves connecting the well bore to the reservoir, which may include treating the formation or installing tubing, packer, or lifting equipment, steps that do not significantly vent natural gas to the atmosphere. This process may also include high-rate flowback of injected gas, water, oil, and proppant used to fracture and prop open new fractures in existing lower permeability gas reservoirs, steps that may vent large quantities of produced gas to the atmosphere.

Source: 40 CFR § 98.6

2.2.1.1 Completions with hydraulic fracturing

Well Completion is the process of making a drilled well ready for production. Well completion is generally broken down into three phases:

– *Casing*, where the piping is run and the cement casing is pumped in.

– *Perforation,* where holes are blasted through the casing at precise locations for stimulation and production flow. This is often done in conjunction with tubing, packing, and setting up the Christmas tree.

– *Stimulation* – where hydraulic fracturing or acidizing is performed. These operations prepare the rock formation for achieving optimal flow.

Hydraulic fracturing is a stimulation treatment routinely performed on oil and gas wells in low-permeability reservoirs. Specially engineered fluids are pumped at high pressure and rate into the reservoir interval to be treated, causing a vertical fracture to open. The wings of the fracture extend away from the wellbore in opposing directions according to the natural stresses within the formation. Proppant, such as grains of sand of a particular size, is mixed with the treatment fluid to keep the fracture open when the treatment is complete. Hydraulic fracturing creates high-conductivity communication with a large area of formation and bypasses any damage that may exist in the near-wellbore area.

With the development of technologically challenging unconventional gas reserves such as tight sands, shale and coalbed methane, completion of new wells in these tight formations typically involve hydraulic fracturing of the reservoir to increase well productivity.

Removing the water and excess proppant (generally sand) during completion and well clean-up may result in significant releases of natural gas, i.e. methane emissions, to the atmosphere.

Reduced emissions completions (RECs) is a term used to describe an alternate practice that captures gas produced during well completions and well workovers following hydraulic fracturing. Portable equipment is brought on site to separate the gas from the solids and liquids produced during the high-rate flowback, and produce gas that can be delivered into the sales pipeline. RECs help to reduce methane and VOC emissions during well cleanup and can eliminate or significantly reduce the need for flaring.

The U.S. EPA has compiled the data it collects under the mandatory GHG reporting program (GHGRP) in the U.S. The data is subdivided into four categories for calculating the corresponding emission factors that can be used for calculating separately emissions associated with oil or gas well completions when hydro fracturing (HF) is used:

– HF Completions: Non-REC with Venting

– HF Completions: Non-REC with Flaring

– HF Completions: REC with Venting

– HF Completions: REC with Flaring

The EFs for each of these categories with be addressed further in Section 6 below.

2.2.1.2 Completions without hydraulic fracturing

As discussed above, well completions comprise of the steps to transform a drilled well in a producing one. It includes the varied processes of making a well ready for production (or injection). Operations principally involve preparing the bottom of the hole to the required specifications, running in the production tubing and with its associated down-hole tools as well as perforating and stimulating the well, as required. Sometimes, the process of running in and cementing the casing is also included. Casing ensures that after a well has been drilled, and the drilling fluids are removed, the well would not eventually close in upon itself and is protecting the well-stream from outside incumbents, like water or sand.

Various flow designs are associated with conventional completions:

– *Casing flow*, where the producing fluid flow has only one path to the surface through the casing.

– *Casing and tubing flow*, where there is tubing within the casing that allows fluid to reach the surface.

– *Pumping flow*, where the tubing and pump are run to a depth beneath the working fluid and the pump and rod string are installed concentrically within the tubing.

– *Tubing flow*, where a tubing string and a production packer are installed and all the flow goes through the tubing.

For completions without hydro fracturing EPA has developed a single emission factor – one for gas wells and one for oil wells. The underlying data used for these emission factors includes information whether the completions were performed with or without flaring.

Table 2-1 provides a list of key emission sources for the oil and gas exploration segment.

Table 2–1. Potential Greenhouse Gas Emission Sources by Sector: Oil & Gas Exploration

EXPLORATION	**CO_2**	**N_2O**	**CH_4**	**Section**
COMBUSTION SOURCES – Stationary Devices				4.0
Internal combustion (IC) engine generators	X	X	X	4.1–4.5
Fire pumps	X	X	X	4.1–4.5
Well drilling	X	X	X	4.1–4.5
COMBUSTION SOURCES – Mobile Sources				4.6
Mobile drilling equipment	X	X	X	4.6
Other company vehicles	X	X	X	4.6
Planes/helicopters	X	X	X	4.6
Supply boats, barges	X	X	X	4.6
Site preparation, construction, and excavation	X	X	X	4.6
WASTE GAS DISPOSAL				5.0
Flares	X	X	X	5.1
Incinerators	X	X	X	5.2
VENTED SOURCES				6.0
Exploratory drilling	X (*)		X	6.2
Well testing and completions	X (*)		X	6.2
Gas sampling and analysis	X (*)		X	6.2, 6.8
Emergency shutdown (ESD)/ emergency safety blowdown (ESB)	X (*)		X	6.3-6.4
Pressure relief valves (PRVs)	X (*)		X	6.3-6.4
Well blowouts (when not flared)	X (*)		X	6.3
Fire Suppression				6.14
FUGITIVE EMISSION SOURCES				7.0
Equipment component leaks	X (*)		X	7.2
Wastewater treatment	X		X	7.5
INDIRECT EMISSION SOURCES				8.0
Electricity imports	X	X	X	8.1
Process heat/steam imports	X	X	X	8.1

2.2.2 Oil and Gas Production

This segment includes the extraction of oil and gas from underground reservoirs, located either onshore or offshore. Because oil and gas can be produced from the same well, the production segment includes gas handling equipment and processing operations.

A well that reaches an economically viable oil and/or natural gas reservoir may be put into production upon completions. A number of steps are potentially involved in the production phase, such as oil/gas separation, oil/water separation and collection, and storage. In addition, the wellhead itself may have a vent to release casing head gas, which could be a source of both CH_4 and CO_2.

The delineation of wells between oil and gas depend on the gas to oil ratio (GOR) of the reservoir fluids. The U.S. EPA and the Energy Information Administration (EIA) use different thresholds for distinguishing between oil and gas wells. The EIA designates wells as either oil or natural gas wells based on a GOR of 6,000 cubic feet (cf) of gas to 1 barrel (bbl.) of oil (cf/bbl.), while the U.S. EPA uses a designation of 100,000 cf/bbl. This different designation results in EIA indicating that there is a lower fraction of oil wells and a higher fraction of gas wells as compared to EPA reporting.

Emissions from oil and gas production occur at the wellhead and may have different characteristics depending on the type and location of the producing reservoirs. The subsections below describe briefly the essential characteristics of five types of production techniques:

- Conventional oil and gas production
- Unconventional oil and gas production
- Offshore oil and gas production
- Oil sands and heavy oil production
- Coal bed methane production

2.2.2.1 Conventional Production

Conventional resources include crude oil and gas and its condensates. Conventional oil and gas are usually associated with highly porous and permeable reservoirs and can be easily tapped by standard vertical wells. However, the categories “conventional” and “unconventional” do not remain fixed, and over time, as economic and technological conditions evolve, resources hitherto considered unconventional can migrate into the conventional category.

In practice conventional resources indicate oil and gas which can be extracted, after the drilling operations, just by the natural pressure of the wells and pumping or compression operations. After the depletion of maturing fields, the natural pressure of the wells may be too low to produce significant quantities of oil and gas. At that stage different techniques may be used to boost production, mainly water and gas injection or depletion compression, but these oil and gas fields will still be conventional resources.

Conventional Oil and Gas is simply known as the traditional way to drill for raw natural gas, crude oil, and petroleum. So what do I mean by traditional? After a well is drilled, oil and gas is extracted by the natural pressure from the wells and pumping operations. Over time, the well may decrease in production. At this time, a conventional well will use an artificial lift or water and gas injections to help increase production.

After production gets to a point where the profits of oil are not enough to cover expenses, the well will usually stop production. If methods beyond an artificial lift or classic methods are used to increase production, then it would be classified at unconventional oil.

A list of emission sources for oil and gas production that is relevant for conventional, unconventional and offshore production is provided in Table 2-2.

Table 2–2. Potential Greenhouse Gas Emission Sources by Sector: Oil & Gas Production

EXPLORATION AND PRODUCTION	**CO_2**	**N_2O**	**CH_4**	**Section**
COMBUSTION SOURCES – Stationary Devices				4.0
Boilers/steam generators	X	X	X	4.1–4.5
Dehydrator reboilers	X	X	X	4.1–4.5
Heaters/treaters	X	X	X	4.1–4.5
Internal combustion (IC) engine generators	X	X	X	4.1–4.5
Fire pumps	X	X	X	4.1–4.5
Reciprocating compressor drivers	X	X	X	4.1–4.5
Turbine electric generators	X	X	X	4.1–4.5
Turbine/centrifugal compressor drivers	X	X	X	4.1–4.5
COMBUSTION SOURCES – Mobile Sources				4.6
Company vehicles	X	X	X	4.6
Planes/helicopters	X	X	X	4.6
WASTE GAS DISPOSAL				5.0
Flares	X	X	X	5.1
Incinerators	X	X	X	5.2
VENTED SOURCES – Process Vents				6.3

EXPLORATION AND PRODUCTION	**CO_2**	**N_2O**	**CH_4**	**Section**
Dehydration processes			X	6.3.8
Dehydrator Kimray pumps			X	6.3.8
Gas sweetening processes	X		X	6.3
Storage tanks and drain vessels	X (*)		X	6.3.9
Pneumatic devices	X (*)		X	6.3.6
Chemical injection pumps	X (*)		X	6.3.7
Gas sampling and analysis	X (*)		X	6.3, 6.8
VENTED SOURCES – Maintenance/Turnarounds				
Mud degassing	X (*)		X	6.2
Low pressure gas well casing	X (*)		X	6.3.5
Compressor blowdowns	X (*)		X	6.4.3
Compressor starts	X (*)		X	6.4.6
Gathering pipeline blowdowns	X (*)		X	6.3-6.4
Vessel blowdown	X (*)		X	6.4
Well workovers	X (*)		X	6.3
Well unloading	X (*)		X	6.3.4
VENTED SOURCES – Non-routine Activities				
Emergency shutdown (ESD)/ emergency safety blowdown (ESB)	X (*)		X	6.3-6.4
Pressure relief valves (PRVs)	X (*)		X	6.3-6.4
Well blowouts (when not flared)	X (*)		X	6.3
Fire Suppression				6.14
FUGITIVE SOURCES				7.0
Equipment component leaks	X (*)		X	7.2
Wastewater treatment	X		X	7.5
Air Conditioning/Refrigeration				7.6
INDIRECT SOURCES				8.0
Electricity imports	X	X	X	8.1
Process heat/steam imports	X	X	X	8.1
Cogeneration	X	X	X	8.2

Footnotes:
Note that this API *Compendium* uses terms (e.g., “routine,” “maintenance,” “point source”) that may have both a commonplace, non-legal meaning, and a specific, legal meaning. The API *Compendium* uses the commonplace, non-legal meanings for these terms and does not use them in their legal sense.
X Indicates if CO_2, CH_4, or N_2O emissions may result from the source.
*Emission estimation approach is provided, but only applicable to CO_2-rich production streams (e.g., CO_2 flood or enhanced oil recovery). Significance of these sources depends on the CO_2 concentration and source-specific emission rate.

The balance between CH_4 and CO_2 emissions from the wellhead and associated equipment leaks can be quite variable. Most reservoir gas has less than 5% CO_2 (mole percent) and a CH_4 content greater than 80%; however, exceptions do exist. For example, in Canada, most wellhead natural gas is below 90% CH_4. Also, some enhanced oil recovery (EOR) techniques involve injection of CO_2 into the formation, potentially resulting in significantly larger CO_2 emissions than CH_4 from equipment/process vents and fugitive leaks. Carbon dioxide injection, as part of a carbon capture and geological storage (CCS) operation, is addressed in more detail in Section 2.2.8.

Oil/gas separation and gas treatment operations may result in CH_4 losses from field tank vents, dehydrators, amine units, and pneumatic devices. Fugitive equipment leaks may also be a source of CH_4 emissions. Combustion emissions result from reciprocating compressors or turbines used to handle produced gas, where the produced gas may be collected for processing (dehydration and/or sweetening), reinjected to boost reservoir pressure, or in some cases, flared. Flaring of produced gas may occur in emergency situations when pressure must be relieved from process vessels and equipment in order to avoid an unsafe condition or catastrophic failure, when there is no infrastructure to process the gas, or when produced gas volumes are too low to be economically collected and processed.

2.2.2.2 Unconventional Production

Unconventional oil and gas production consists of extracting resources from a wider variety of reservoir formations, such as:

– *Shale oil* – refers to a high-quality crude oil that lies between layers of shale rock, impermeable mudstone, or siltstone. This resource is produced by fracturing the layers of rock that contain the layers of oil. This type of production should *not be confused with* *oil shale*, which is rock suffused with kerogen, a precursor to oil.

– *Shale gas* – refers to gas that remains trapped in its original source rock, the organic-rich shale that formed from the sedimentary deposition of mud, silt, clay, and organic matter on the floors of shallow seas. Shale gas is the fastest growing natural gas resource in the United States and worldwide as a result of several recent technological developments. These include horizontal drilling that allow a single well to pass through larger volumes of a shale gas reservoir and thus produce more gas and the refinement of hydraulic fracturing technology that enables improved access to shale gas deposits.

– *Tight gas* - refers to natural gas that has migrated into a reservoir rock with high porosity but low permeability. These types of reservoirs are not usually associated with oil and commonly require horizontal drilling and hydraulic fracturing to increase well output to cost-effective levels.

– *Coal-Bed Methane* - refers to methane gas that can be found trapped within coal deposits, including from otherwise inaccessible coal seams, and which can be tapped and collected by employing similar well-drilling and hydraulic fracturing techniques as are used in shale gas extraction.

With the exception of the formation specific exploration techniques that are applied in the initial stages (drilling through completions), the ensuing production operations stages and equipment are similar for all types of the different types of reservoirs.

2.2.2.3 Offshore Production

Offshore oil and gas production, which involves extracting oil and gas from beneath the sea, is a critical component of the world's energy supply. It requires the use of increasingly sophisticated technology and ever greater attention to the related environmental impacts. Offshore oil and gas production operations are similar to onshore operations. Equipment and process configurations are typically the same, although vented and fugitive CH_4 emission sources are generally smaller than for onshore operations due to tight space confinements on platforms and increased emphasis on personnel safety and risk/loss prevention. Offshore operations may include combustion emissions from equipment and personnel transport to and from the platforms (supply boats and helicopters) that are not generally associated with onshore operations.

Offshore production is moving farther and farther offshore, and is also known as ‘deepwater production’. These production facilities may pose some challenges due to their unique design and operating environment:

– *Floating facilities* – that are connected to the wells using flexible riser. Some risers are used to inject the water and gas that pushes the oil towards the production wells, while others transport the oil to the surface. The risers are encased in insulating sleeves to prevent the oil – which is extracted at more than 50°C – from cooling too quickly in the deepwater conditions and the paraffin from obstructing the pipes. More and more operations, such as separating oil from gas, are being performed under the sea, turning these installations into a sort of underwater processing facility.

Network of pipelines - can be used to bring the oil onshore. However, if the oil field is situated too far off the coast and more than 1,000 meters deep, a barge or a tanker is generally used to produce, store and offload the oil. These vessels are known as Floating, Production, Storage and Offloading (FPSOs) systems. FPSO systems, which are a subset of offshore operations, may also have additonal emissions due to their storage and offloading capabilities.

2.2.2.4 Oil Sands and Heavy Oil Upgrading

This segment includes the non-conventional extraction of heavy oil in the form of bitumen from sand deposits, and the subsequent conversion of the bitumen to synthetic crude oil. Oil sands (sometimes called tar sands) are naturally occurring mixtures of clay, sand, water, and bitumen. Bitumen can be separated from the oil sands through multiple methods: surface mining and extraction, or in-situ recovery. The bitumen is then upgraded, removing carbon and adding hydrogen to produce synthetic crude oil.

Oil sands GHG emission sources vary by operation but can include mining activities (mobile equipment), fine tailings ponds, combustion sources, hydrogen generation, sulfur recovery, and equipment leak sources. A detailed overview of the oil sands and heavy oil upgrading process can be found in the document *CH_4 and VOC Emissions from the Canadian Upstream Oil and Gas Industry Volume 3: Organic and Common-Pollutant Emissions by the Canadian Oil sands Industry and from Heavy Oil Upgrading Facilities* (CAPP, 1999).

A checklist of emission sources for this industry segment is provided in Table 2-3.

Table 2–3. Potential Greenhouse Gas Emission Sources by Sector: Oil Sands and Heavy Oil Upgrading

EXPLORATION AND PRODUCTION	CO_2	N_2O	CH_4	Section
COMBUSTION SOURCES – Stationary Devices				4.0
Boilers/heaters	X	X	X	4.1–4.5
Fire pumps	X	X	X	4.1–4.5
Internal combustion (IC) engine generators	X	X	X	4.1–4.5
Reciprocating compressor	X	X	X	4.1–4.5
Turbine electric generators	X	X	X	4.1–4.5
Turbine/centrifugal compressor	X	X	X	4.1–4.5
Turbines	X	X	X	4.1–4.5
Mining equipment	X	X	X	4.1–4.5
COMBUSTION SOURCES – Mobile Sources				4.6
Mining equipment	X	X	X	4.6
Other company vehicles	X	X	X	4.6
Planes/helicopters	X	X	X	4.6
Site preparation, construction, and excavation	X	X	X	4.6
WASTE GAS DISPOSAL				5.0
Flares	X	X	X	5.1
Catalytic oxidizers	X			5.2
Incinerators	X	X	X	5.2
VENTED SOURCES – Process Vents				6.0
Flue gas desulfurization process vents	X			6.11
Sulfur recovery units	X			6.3.8
Catalytic cracking	X			6.11
Catalyst regeneration	X			6.11
Steam methane reforming (hydrogen plants)	X			6.11
Delayed coking	X			6.11

EXPLORATION AND PRODUCTION	**CO_2**	**N_2O**	**CH_4**	**Section**
Flexi-coking	X			6.11
Catalytic reforming	X			6.11
Thermal cracking	X			6.11
VENTED SOURCES – Other Venting				
Storage tanks			X	6.3.9
Water tanks			X	6.3.9
Pneumatic devices			X	6.3.6
Casing gas vents			X	6.3.5
VENTED SOURCES – Maintenance/Turnarounds				
Compressor blowdowns			X	6.4.3
Compressor starts			X	6.4.6
Equipment/process blowdowns			X	6.4.6
Heater/boiler tube decoking			X	6.11
Vessel blowdown			X	6.4
VENTED SOURCES – Non-routine Activities				
Emergency shut down (ESD)			X	6.3-6.4
Pressure relief valves (PRVs)			X	6.3-6.4
Fire suppression				6.14
FUGITIVE SOURCES				7.0
Equipment component leaks	X		X	7.2
Wastewater treatment	X		X	7.5
Sludge/solids handling			X	7.5
Wastewater collection and treating			X	7.5
Air conditioning/refrigeration				7.6
Exposed mine faces			X	NA
Tailing ponds			X	NA
INDIRECT SOURCES				8.0
Electricity imports	X	X	X	8.1
Process heat/steam imports	X	X	X	8.1

Footnotes:

Note that this API *Compendium* uses terms (e.g., "routine," "maintenance," "point source") that may have both a commonplace, non-legal meaning, and a specific, legal meaning. The API *Compendium* uses the commonplace, non-legal meanings for these terms and does not use them in their legal sense.

X Indicates if CO_2, CH_4, or N_2O emissions may result from the source.

NA indicates a souce specific GHG estimation methodology or emission factor is not currently available.

Emissions from oil sands mining operations result from the volatilization of CH_4 entrained in the oil sands during mining and mine dewatering, from exposed mine faces, and during transport and handling of the ore and oil sands. Unlike coal mining, for which emission factors are presented in Section 5, oil sands mining activities currently do not have published emission factors. Site-specific data should be used to account for these emissions.

The largest source of CH_4 emissions from oil sands operations are tailing ponds. The processes resulting in emissions from tailing ponds are currently being studied; however, it appears that the emissions are due to microbial degradation of hydrocarbons in the tailings. As a result, the emissions from tailings ponds are highly site specific. There currently are no emission factors available for estimating emissions from tailings and therefore site specific data or measurements should be used for estimating these emissions.

The processes involved in bitumen upgrading include coking and hydroprocessing; these emission sources are discussed in more detail in Section 2.2.10 (Refining). Upgrading facilities may also have cogeneration and utility plants for which emissions may need to be allocated using a methodology provided in Section 8. Sulfur recovery units or limestone-based flue gas desulfurization plants may also be used to remove sulfur from process streams.

2.2.2.5 Coal Bed Methane Production

Coal bed methane (CBM) is another method of producing CH_4 (natural gas). The process of coalification, in which swamp vegetation is converted to coal by geological and biological forces, also captures CH_4 in the coal seams and the surrounding rock strata. At the high pressures in the coal seams, the CH_4 either remains adsorbed on the coal surface or is trapped within the coal's porous structure. This CH_4 can be recovered for use or sale, just as associated gas can be recovered from crude production wells.

The emission sources from CBM production are very similar to those from petroleum exploration and production discussed in Section 2.2.1. A checklist of possible sources is provided in Table 2-4.

Table 2–4. Potential Greenhouse Gas Emission Sources by Sector: Coal Bed Methane Production

COAL BED METHANE PRODUCTION	**CO_2**	**N_2O**	**CH_4**	**Section**
COMBUSTION SOURCES – Stationary Devices				4.0
Boilers/steam generators	X	X	X	4.1-4.5
Dehydrator reboilers	X	X	X	4.1-4.5
Fire pumps	X	X	X	4.1-4.5
Internal combustion (IC) engines and generators	X	X	X	4.1-4.5
Reciprocating compressor	X	X	X	4.1-4.5
Turbine electric generators	X	X	X	4.1-4.5
Turbine/centrifugal compressor	X	X	X	4.1-4.5
COMBUSTION SOURCES – Mobile Sources				4.6
Mining equipment	X	X	X	4.6
Other company vehicles	X	X	X	4.6
Site preparation, construction, and excavation	X	X	X	4.6
WASTE GAS DISPOSAL				5.0
Flares	X	X	X	5.1
VENTED SOURCES – Process Vents				6.0
Dehydration processes			X	6.3.8
Dehydrator Kimray pump			X	6.3.8
Gas sweetening processes	X		X	6.3

COAL BED METHANE PRODUCTION	CO_2	N_2O	CH_4	Section
VENTED SOURCES – Other Venting				
Water handling, tanks			X	6.3.9
Coal seam drilling and well testing			X	6.2.4
Coal handling			X	6.2.4
VENTED SOURCES – Maintenance/Turnarounds				
Gas sampling and analysis			X	6.2, 6.8
Compressor starts and blowdowns			X	6.4.3, 6.4.6
Gathering pipeline blowdowns			X	6.3-6.4
Vessel blowdowns			X	6.4
Well workovers			X	6.3
VENTED SOURCES – Non-routine Activities				
Gathering pipeline leaks			X	6.4
Pressure relief valves (PRVs)			X	6.3-6.4
Well blowdowns (when not flared)			X	6.3
Fire suppression				6.14
FUGITIVE SOURCES				7.0
Equipment component leaks			X	7.2
Wastewater treatment	X		X	7.5
Air conditioning/refrigeration				7.6
INDIRECT SOURCES				8.0
Electricity imports	X	X	X	8.1
Process heat/steam imports	X	X	X	8.1

Footnotes:
X Indicates if CO_2, CH_4, or N_2O emissions may result from the source

In conventional CBM operations, several gas production wells are drilled from the surface to the coal seam and the pressure in the coal beds is reduced, thereby releasing the CH_4. GHG emissions result from the engines used to drill the production wells. Flaring emissions are not routine but may occur if the natural gas is flared prior to tying into a production facility or due to process upsets.

Emission sources associated with producing CBM are largely the same as those associated with conventional natural gas production. The recovered CBM is separated from other contaminants (e.g., formation water, CO_2) at the surface. Process equipment, such as separators, water tanks, dehydrators, amine units, and/or pneumatic devices result in vented and fugitive emissions through the same mechanisms as conventional natural gas production. Combustion emissions result from compressors used to transport the recovered natural gas.

2.2.3 Oil and Gas Gathering and Boosting

The oil and gas gathering and boosting segment is defined by the U.S. EPA at §98.230, as part of mandatory reporting under the GHGRP. It consists of the gathering pipelines and other equipment used to collect petroleum and/or natural gas from onshore production gas or oil wells and used to compress, dehydrate, sweeten, or transport the petroleum and/or natural gas to a natural gas processing facility, a natural gas transmission pipeline or to a natural gas distribution pipeline. Gathering and boosting equipment includes, but is not limited to gathering pipelines, separators, compressors, acid gas removal units, dehydrators, pneumatic devices/pumps, storage vessels, engines, boilers, heaters, and flares.

The EPA cautions about double counting gathering and boosting operations by stating, *"Gathering and boosting equipment does not include equipment reported under any other industry segment defined in this section".* Review of Gathering & Boosting data, which has been reported in the U.S. since 2016, reveals that CO_2 and CH_4 emissions represent close to 75% and 25%, respectively, of the overall CO2e emissions from this segment. Combustion equipment was the top reported emission source, followed by miscellaneous equipment leaks, pneumatic devices and atmospheric tanks.

A list of potential emission sources in the gathering and boosting segment is provided in Table 2-5.

Table 2–5. Potential Greenhouse Gas Emission Sources by Sector: Oil & Gas Gathering and Boosting

GATHERING AND BOOSTING	**CO_2**	**N_2O**	**CH_4**	**Section**
COMBUSTION SOURCES – Stationary Devices				4.0
Dehydrator reboilers	X	X	X	4.1-4.5
Fire pumps	X	X	X	4.1-4.5
Internal combustion (IC) engines and generators	X	X	X	4.1-4.5
Reciprocating compressors	X	X	X	4.1-4.5
Centrifugal compressors	X	X	X	4.1-4.5
COMBUSTION SOURCES – Mobile Sources				4.6
Company vehicles	X	X	X	4.6
Helicopters/trains	X	X	X	4.6
WASTE GAS DISPOSAL				5.0
Flares	X	X	X	5.1
VENTED SOURCES				6.0
Dehydration processes			X	6.3.8
Dehydrator Kimray pump			X	6.3.8
Acid Gas Removal	X		X	6.4.4
Pneumatic controllers			X	6.3.6
Atmospheric tanks			X	6.3.9
VENTED SOURCES – Maintenance/Turnarounds				
Gas sampling and analysis			X	6.3, 6.8
Compressor starts and blowdowns			X	6.4.3, 6.4.6
Gathering pipeline blowdowns			X	6.3-6.4
Vessel blowdowns			X	6.4
VENTED SOURCES – Non-routine Activities				
Gathering pipeline leaks			X	6.4
Pressure relief valves (PRVs)			X	6.3-6.4
Well blowdowns (when not flared)			X	6.3

GATHERING AND BOOSTING	CO_2	N_2O	CH_4	Section
Fire suppression				6.14
FUGITIVE SOURCES				7.0
Equipment component leaks			X	7.2
Air conditioning/refrigeration				7.6
INDIRECT SOURCES				8.0
Electricity imports	X	X	X	8.1
Process heat/steam imports	X	X	X	8.1

Footnotes:
X Indicates if CO_2, CH_4, or N_2O emissions may result from the source

2.2.4 Natural Gas Processing

This segment addresses natural gas processing operations. Raw natural gas id produced from three types of wells: oil wells, gas wells, and condensate wells. Natural gas that comes from oil wells is typically termed 'associated gas'. Whatever the source of the natural gas, once separated from crude oil (if present) it commonly exists in mixtures with other hydrocarbons; principally ethane, propane, butane, and pentanes. In addition, raw natural gas contains water vapor, hydrogen sulfide (H_2S), carbon dioxide, helium, nitrogen, and other compounds.

Natural gas processing consists of separating higher molecular weight hydrocarbons and fluids from the pure natural gas, to produce what is known as 'pipeline quality' dry natural gas. Major transportation pipelines usually impose restrictions on the make-up of the natural gas that is allowed into the pipeline. That means that before the natural gas can be transported it must be purified.

During natural gas processing, high value liquid products may be recovered from the natural gas stream following the produced gas being treated to meet pipeline specifications for transmission. Process vents from dehydration, gas sweetening, pneumatic devices, and non-routine activities may result in CH_4 emissions. Fugitive equipment leaks are also a source of CH_4 emissions. Combustion sources, such as boilers, heaters, engines, and flares result in CO_2 emissions, as well as smaller quantities of N_2O and CH_4 emissions.

Offshore operations may also include oil and gas processing.

The list of emission sources for this industry segment is provided in Table 2-6.

Table 2–6. Potential Greenhouse Gas Emission Sources by Sector: Natural Gas Processing

PROCESSING	CO_2	N_2O	CH_4	Section
COMBUSTION SOURCES – Stationary Devices				4.0
Boilers/steam generators	X	X	X	4.1-4.5
Dehydrator reboilers	X	X	X	4.1-4.5

PROCESSING	CO_2	N_2O	CH_4	Section
Fire pumps	X	X	X	4.1-4.5
Internal combustion (IC) engine generators	X	X	X	4.1-4.5
Reciprocating compressor	X	X	X	4.1-4.5
Turbine electric generators	X	X	X	4.1-4.5
Turbine/centrifugal compressor	X	X	X	4.1-4.5
COMBUSTION SOURCES – Mobile Sources				4.6
Other company vehicles	X	X	X	4.6
Planes/helicopters	X	X	X	4.6
Supply boats, barges	X	X	X	4.6
WASTE GAS DISPOSAL				5.0
Flares	X	X	X	5.1
Catalytic and thermal oxidizers	X			5.2
Incinerators	X	X	X	5.2
VENTED SOURCES – Process Vents				6.0
Dehydration processes	X (*)		X	6.3.8
Dehydrator Kimray pumps	X (*)		X	6.3.8
Gas sweetening processes	X (*)		X	6.3
Sulfur recovery units	X			6.4.4
VENTED SOURCES – Other Venting				
Storage tanks and drain vessels	X (*)		X	6.3.9
Pneumatic devices	X (*)		X	6.3.6
Chemical injection pumps	X (*)		X	6.3.7
VENTED SOURCES – Maintenance/Turnarounds				
Gas sampling and analysis	X (*)		X	6.3, 6.8
Compressor blowdowns	X (*)		X	6.3-6.4
Compressor starts	X (*)		X	6.4.6
Vessel blowdown	X (*)		X	6.4
VENTED SOURCES – Non-routine Activities				
Emergency shutdown (ESD)/ emergency safety blowdown (ESB)	X (*)		X	6.3-6.4
Pressure relief valves (PRVs)	X (*)		X	6.3-6.4
Fire suppression				6.14
FUGITIVE SOURCES				7.0
Equipment component leaks	X (*)		X	7.3
Wastewater treatment	X		X	7.5
Air conditioning/refrigeration				7.6
INDIRECT SOURCES				8.0
Electricity imports	X	X	X	8.1
Process heat/steam imports	X	X	X	8.1

Footnotes:
X Indicates if CO_2, CH_4, or N_2O emissions may result from the source.
*Emission estimation approach is provided, but only applicable to CO_2-rich streams. Significance of these sources depends on the CO_2 concentration and source-specific emission rate.

2.2.4.1 Natural Gas Liquids Fractionation

Once the acid gases and water are removed from the gas stream, it is now classified as dry, sweet gas, and is suitable for even further processing. The next step is natural gas liquids (NGL)

Liquids) extraction and fractionation. These processes are dictated by the profitability that is measured the difference between the potential revenue from sales of NGL's contained in the gas stream as liquid and their value if left in the gas pipeline and sold at gas price. NGLs are hydrocarbons removed (condensed) as a liquid from a hydrocarbon stream that is originally in a vapor phase and it typically can be fractionated into ethane, propane, butanes, and "natural gasoline", which consist of pentanes and heavier hydrocarbons. The fractionated NGLs are kept in a liquid state for storage, shipping and consumption.

The removal of NGLs usually takes place in a relatively centralized processing plant, and uses techniques similar to those used to dehydrate natural gas. The two principle techniques, which account for around 90% of total NGLs production, include: the absorption method and the cryogenic expander process. Once NGLs have been removed from the natural gas stream, they must be separated out into their base components. The process used to accomplish this task is called fractionation, which works on the basis of the different boiling points of the different hydrocarbons in the NGL stream, proceeding from the lightest hydrocarbons to the heaviest.

The efficiency of NGL fractionation is dependent on inlet gas composition, flowrate and plant configuration, which influence plant recovery rates. The value of GHG emissions per gallon of NGL recovered provides an indicator of the plant overall efficiency. When benchmarking GHG emissions from cryogenic gas processing, these values have been found to range from 0.01 to 0.075 metric tonnes of CO_2e per gallon of NGL recovered[1].

2.2.4.2 Natural Gas Transmission and Storage

Natural gas is typically moves from the gathering system – before or after natural gas processing - into the natural gas transmission system. The large transmission lines move large amounts of natural gas thousands of miles directly to large consumers such power plants or to local distribution companies (LDCs). The pressure of gas in each section of line typically ranges from 200 pounds to 1,500 pounds per square inch, depending on the type of area in which the pipeline is operating. Compressor stations are located approximately every 50 to 60 miles along each pipeline to boost the pressure that is lost through the friction of the natural gas moving through the steel pipe.

GHG emissions from the natural gas transmission segment include emissions from pipeline blowdown vent stacks, and emissions associated with compressors operations. The blow down vent stacks emissions consist primarily of CH_4 emissions, while for transmission compression,

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[1] http://www.gasprocessingnews.com/features/201412/benchmarking-ghg-emissions-from-cryogenic-gas-processing.aspx

CH_4 and CO_2 emissions represent around 18% and 82%, respectively, of the total CO_2e emissions for this segment.

Natural gas storage facilities are used to store natural gas produced during off-peak times (usually summer) so that gas can be delivered during peak demand. Storage facilities can be below or above ground. Above ground facilities liquefy the gas by super cooling and then storing the LNG in heavily insulated tanks. Below-ground facilities compress and store natural gas in the vapor phase in one of several formations: 1) spent gas production fields, 2) aquifers, or 3) salt caverns.

For the natural gas storage segment GHG emissions seem to be split about evenly between CH_4 and CO_2, with the largest sources of emissions being combustion equipment and reciprocating compressors, which amount to over 50% and 30%, respectively, of the total CO_{2e} emissions.

A list of emission sources that may be associated with natural gas transmission and storage is provided in Table 2-7.

Table 2–7. Potential Greenhouse Gas Emission Sources by Sector: Natural Gas Transmission and Storage

NATURAL GAS TRANSMISSION AND STORAGE	CO_2	N_2O	CH_4	Section
COMBUSTION SOURCES – Stationary Devices				4.0
Boilers/steam generators	X	X	X	4.1-4.5
Dehydrator reboilers	X	X	X	4.1-4.5
Heaters	X	X	X	4.1-4.5
Fire pumps	X	X	X	4.1-4.5
Internal combustion (IC) engine generators	X	X	X	4.1-4.5
Reciprocating compressors	X	X	X	4.1-4.5
Turbine electric generators	X	X	X	4.1-4.5
Turbine/centrifugal compressor	X	X	X	4.1-4.5
COMBUSTION SOURCES – Mobile Sources				4.6
Other company vehicles	X	X	X	4.6
Planes/helicopters	X	X	X	4.6
WASTE GAS DISPOSAL				5.0
Flares	X	X	X	5.1
Catalytic and thermal oxidizers	X			5.2
Incinerators	X	X	X	5.2
VENTED SOURCES – Process Vents				6.0
Dehydration processes			X	6.3.8
Dehydrator Kimray pumps			X	6.3.8
Gas treatment processes	X		X	6.5.2
VENTED SOURCES – Other Venting				
Gas sampling and analysis			X	6.3, 6.8
Storage tanks			X	6.3.9
Loading/unloading/transit			X	6.3
Pneumatic devices			X	6.6.3
Chemical injection pumps			X	6.3.7
VENTED SOURCES – Maintenance/Turnarounds				
Compressor blowdowns			X	6.4.3
Compressor starts			X	6.4.6
Compressor station blowdowns			X	6.5.5
Pig traps and drips			X	6.6
Vessel blowdown			X	6.4
Pipeline blowdowns			X	6.6
VENTED SOURCES – Non-routine Activities				
Metering and Pressure Regulating (M&R) station upsets			X	6.6
Pressure relief valves (PRVs)			X	6.6
Pipeline dig-ins			X	6.6
Fire suppression				6.14
FUGITIVE SOURCES				7.0
Pipeline leaks			X	7.3
Process equipment leaks			X	7.3
Wastewater treatment			X	7.5
Air conditioning/refrigeration				7.6
INDIRECT SOURCES				8.0

NATURAL GAS TRANSMISSION AND STORAGE	CO_2	N_2O	CH_4	Section
Electricity imports	X	X	X	8.1
Process heat/steam imports	X	X	X	8.1

Footnotes:
X Indicates if CO_2, CH_4, or N_2O emissions may result from the source.

2.2.5 Liquefied Natural Gas (LNG) Operations

Liquefied natural gas, or LNG, is natural gas that is refrigerated to a temperature of about minus 160°C (or minus 260°F) at atmospheric pressure; it becomes a clear, colorless, and odorless liquid. This reduces its volume by a factor of more than 600, allowing it to be efficiently stored for multiple uses and transported in specially designed tankers by sea or land. Prior to the liquefaction process, natural gas is treated to remove essentially all of its non-hydrocarbon components (carbon dioxide, mercury, sulfur compounds, and water) with the exception of nitrogen, and some heavier hydrocarbons contained within the natural gas, resulting in an LNG composition that is typically over 95% methane and ethane with less than 5% of other hydrocarbons (ethane, propane, and butanes) and nitrogen. The nitrogen content of the LNG is reduced to typically one percent or less prior to storage at the liquefaction facility.

The LNG operations chain consists of several interconnected operating segments such as: LNG storage; LNG shipping and transport; LNG import and regasification; and LNG export and liquefaction.

Table 2-8 provides a listing of emission sources that may be found throughout the LNG operations chain. Each of these operating segments is discussed briefly below. Further elaboration of the LNG supply chain emission sources is provided in API’s 2015 guideline document.

LNG systems are designed to avoid contact with the outside air, which would gasify the LNG. Thus, great effort is taken to prevent vented and fugitive losses. Vapor recovery systems are used to capture BOG and re-route it for use as a fuel or to the send-out natural gas pipeline. In an emergency, flares are available to burn the CH4 rather than release it to the atmosphere. Once the CH_4 is vaporized, emission factors applicable to natural gas storage or pipeline operations apply.

Table 2–8. Potential Greenhouse Gas Emission Sources by Sector: Liquefied Natural Gas (LNG) Operations

LIQUEFIED NATURAL GAS OPERATIONS	CO_2	N_2O	CH_4	Section
COMBUSTION SOURCES – Stationary Devices				4.0
Boilers/steam generators	X	X	X	4.1-4.5
Dehydrator reboilers	X	X	X	4.1-4.5
Line Heaters	X	X	X	4.1-4.5
Fire pumps	X	X	X	4.1-4.5
Internal combustion (IC) engine generators	X	X	X	4.1-4.5
Reciprocating compressors	X	X	X	4.1-4.5
Turbine electric generators	X	X	X	4.1-4.5
Turbine/centrifugal compressor	X	X	X	4.1-4.5
Submerged Combustion Vaporizers	X	X		4.1-4.5
COMBUSTION SOURCES – Mobile Sources				4.6
Company vehicles	X	X	X	4.6
Planes/helicopters	X	X	X	4.6
LNG carriers	X		X	4.6
Rescue boats/Coast Guard Escort	X	X	X	4.6
Tugs/Support Vessels	X	X	X	4.6
WASTE GAS DISPOSAL				5.0
Flares	X	X	X	5.1
Catalytic and thermal oxidizers	X			5.2
Incinerators	X	X	X	5.2
VENTED SOURCES – Process Vents				
Dehydration processes			X	6.3.8
Dehydrator Kimray pumps			X	6.3.8
Gas treatment processes	X		X	6.4.4
Cryogenic exchangers			X	6.7
Vaporization	X		X	6.7
VENTED SOURCES – Other Venting				
Gas sampling and analysis			X	6.3, 6.8
Storage tanks/BOG Venting			X	6.7.2
Loading/unloading/transit			X	6.7.2
Pneumatic devices			X	6.3.6
Chemical injection pumps			X	6.3.7
LNG Cold Box	X			
VENTED SOURCES – Maintenance/Turnarounds				
Compressor blowdowns			X	6.4.3
Compressor starts			X	6.4.6
Compressor station blowdowns			X	6.5.5
Vessel blowdown			X	6.4
VENTED SOURCES – Non-routine Activities				
Metering and Pressure Regulating (M&R) station upsets			X	6.6
Pressure relief valves (PRVs)			X	6.3-6.4, 6.8
Pipeline dig-ins			X	6.6
Fire suppression				6.14
FUGITIVE SOURCES				7.0
Pressure relief devices			X	7.3

Process equipment leaks			X	7.3
Coupling connectors (loading/unloading)			X	7.3
Air conditioning/refrigeration				7.6
INDIRECT SOURCES				8.0
Electricity imports	X	X	X	8.1
Process heat/steam imports	X	X	X	8.1

Footnotes:
X Indicates if CO_2, CH_4, or N_2O emissions may result from the source

2.2.5.1 LNG Storage

LNG storage tanks are located at liquefaction plants and at export and import terminals to store LNG prior to loading onto tankers or prior to regasification. In addition, LNG storage tanks may be used in natural gas distribution systems for surge capacity to help meet peak demand; such tanks are part of a “peak-shaving” facility.

LNG storage tanks are typically double-walled tanks (i.e., a tank within a tank), with the annular space between the two tank walls filled with insulation. The inner tank, in contact with the LNG, is made of material suitable for cryogenic service such as 9% nickel steel or aluminum. The outer tank includes a dome that, with the outer tank wall and floor, and its lining, provides containment for the vapor that exists in equilibrium with the LNG.

Greenhouse gas emissions from LNG storage tanks are minimal since:

– There is no systematic venting from the tanks: gas is fully contained within the outer container of the overall tank design;

– Gas displaced during tank loading or boiled off due to heat leakage is captured and either used for fuel gas onsite; compressed and sent to a transmission or distribution system pipeline; or reliquefied and returned to the storage tank;

– Most piping connections associated with LNG tanks are welded rather than flanged;

– LNG storage tanks are operated near atmospheric pressure with a slight overpressure so there is minimal pressure differential between the tank and the atmosphere to drive leaks;

– The tanks are double-walled and heavily insulated to minimize evaporative losses, while their tank in a tank design minimizes the potential for liquid leaks.

2.2.5.2 LNG Shipping and Transport

LNG tankers typically burn the natural gas boiled off from the stored LNG as fuel, supplemented by fuel oil, to power their propulsion system. Newer ships also utilize slow speed diesel-powered propulsion systems and have onboard reliquefaction facilities to reliquefy boil-off gas and return it to the ship's tanks as LNG.

LNG ship operations generate GHG emissions while traveling at sea, while berthing and/or un-berthing from the docks, and while loading and unloading their cargo. One should account for the GHG emissions associated with any routine operations at dock (i.e. 'hoteling' operations), the duration of operation, and the power demand of the cargo transfer pumps, in addition to the loading/unloading operations discussed further below.

For berthing and unberthing operations the LNG ships use specialized couplings to ensure safe LNG transfer, which are known as quick coupling (QC) and quick release (QR). Vessels are also equipped with powered quick release couplings for emergency disconnects of products transfer if it becomes necessary.

Marine loading and unloading terminals are associated with liquefaction and exporting of LONG, or at import terminals prior to LNG regasification. LNG loading arms, typically constructed from pipe with cryogenic swivels, are used to transfer LNG between onshore or offshore facilities and LNG tankers, both in liquefaction and regasification plants. LNG is maintained at cryogenic temperature throughout the loading and unloading process. Specially designed and well-insulated loading racks and vessel connectors are used to minimize generation of BOG and to ensure safety of the LNG transfer process.

During ship unloading operations, a portion of the BOG is returned to the ship to compensate for the volume of liquid pumped out to maintain the ship's tank pressure. BOG that is not returned to the ship is compressed, condensed by direct contact with LNG, and then combined with the send-out natural gas prior to being pumped up to pipeline pressure in the send-out pumps.

With the emergence of offshore LNG operations, different designs are used for loading and offloading LNG under different conditions, such as from regasification or liquefaction plants in environments that are more severe than the protected harbors typically employed with onshore liquefaction plants and receiving terminals.

2.2.5.3 LNG Import and Regasification

Regasification plants, which return the LNG back into the gaseous state, are typically incorporated into LNG receiving (import) terminals. Regasification plants vary in their processing capabilities. Most LNG import terminals are only capable of pumping and vaporizing LNG. Some have the ability to blend nitrogen into the send out gas to reduce its heating value, or to blend in propane and/or butanes into the LNG to increase its heating value. A limited number of import terminals have facilities to separate higher hydrocarbons from rich LNG.

The vaporizers commonly in use throughout the world include:

– Submerged Combustion Vaporizers (SCV)
– Open Rack Vaporizers (ORV)
– Shell & Tube Vaporizers (STV)
– Ambient Air Vaporizers (AAV)

The vaporizers presently in use in the U.S. are mostly submerged combustion or shell and tube design. Elsewhere in the world, other types like open rack seawater type and intermediate fluid type are in use. The pressurized natural gas from the regasification process is either delivered to adjacent consumers, or enters into a natural gas pipeline transmission and distribution system.

For all LNG regasification plants, LNG is initially pumped from the LNG ship into the receiving terminal's LNG storage tanks. Subsequently, LNG is either transferred further in its liquid phase, e.g. loaded onto trucks for transport to smaller storage facilities at a customer's site, or pumped to higher pressure through in-tank and high pressure pumps, vaporized at high pressure, and delivered into the send out gas pipeline.

Due to the varied composition of LNG received at terminals additional processing or dilution steps may be required after regasification in order to meet national or local gas quality specifications and the needs of end-users. These additional processing steps could also lead to additional GHG emissions, which would have to be assessed based on the local operational boundaries for the regasification plants. For many regasification facilities, the vast majority of GHG emissions stem from combustion processes, with minimal venting due to compressor operations. Yet, one should note that some regasification plants also have power generating capability, with its associated emissions

2.2.5.4 LNG Export and Liquefaction

Natural gas arriving at a liquefaction plant may either be processed or unprocessed (raw) natural gas. Prior to liquefaction, the natural gas has to be essentially free of water, sulfur-containing species (primarily hydrogen sulfide), and any residual CO_2. It is also treated to remove other components that could freeze (e.g., benzene) under the low temperatures needed for liquefaction, or that could be harmful (e.g. mercury) to the liquefaction facility.

There are different designs for the liquefaction process and it also includes recovery of the BOG during LNG ship loading. The BOG can either be routed to the plant's fuel gas system, or compressed and returned to the inlet of the process. LNG typically contains at least 90% methane, along with smaller and decreasing amounts of ethane, propane, and butanes. The liquefaction process entails chilling the natural gas using refrigerants, which are typically hydrocarbons, although non-hydrocarbons (e.g. nitrogen) may also be used. The liquefaction plant uses multiple compressors, condensers, pressure expansion valves, isentropic expanders and evaporators. The natural gas goes through stages of pre-cooling, liquefaction and sub-cooling until it reaches the desired temperature, and is then stored as LNG in near-atmospheric pressure tanks prior to ship loading.

Liquefaction process GHG emissions are primarily due – but not limited - to:

– *Fuel gas combustion* to power heaters, refrigeration compressors and electrical generators;

– *Waste gas combustion* including flares and incinerators;

– *Venting* of low pressure carbon dioxide;

– *Fugitive losses* of natural gas from process equipment leaks and other GHG's used in the facility (i.e., SF_6 used for switchgear).

The liquefaction process may be designed to produce a rich (high in heating value) or lean (low in heating value) LNG, per customers' specifications. It is important to note some LNG facilities may produce surplus electrical power that is export to the local areas, or it may extract a natural gas liquids stream that could be fractionated for sale. Therefore, when estimating GHG emissions it is important to properly account for the overall material balance of the plant products, since not all are emission sources.

2.2.6 Natural Gas Distribution

The natural gas distribution pipeline systems bring natural gas to homes and businesses through large distribution lines mains and service lines, including both onshore and offshore lines. This is the final step in delivering natural gas to customers. Distribution pipelines take the high-pressure gas from the transmission system at "city gate" stations, reduce the pressure and distribute the gas through primarily underground mains and service lines to individual end users.

Large industrial, commercial, and electric generation customers receive natural gas directly from high capacity interstate and intrastate pipelines, while most other users receive natural gas from their local gas utility, also known as a local distribution company (LDC).

Distribution system emissions result mainly from leak emissions from pipelines and stations. Increased use of plastic piping, which has lower emissions than other pipe materials, leads to reduced CH_4 and CO_2 emissions from this segment. Other emission reductions are attributable to upgrades at metering and regulating (M&R) stations. According to the data reported to EPA's GHGRP, CH_4 emissions constitute about 98% of overall GHG emissions from the natural gas distribution segment.

An indicative list of emission sources for the natural gas distribution segment is provided in Table 2-9.

Table 2–9. Potential Greenhouse Gas Emission Sources by Sector: Natural Gas Distribution

NATURAL GAS DISTRIBUTION	CO_2	N_2O	CH_4	Section
COMBUSTION SOURCES – Stationary Devices				4.0
Boilers/steam generators	X	X	X	4.1-4.5
Dehydrator reboilers	X	X	X	4.1-4.5
Heaters	X	X	X	4.1-4.5
Fire pumps	X	X	X	4.1-4.5
Internal combustion (IC) engine generators	X	X	X	4.1-4.5
Reciprocating compressor	X	X	X	4.1-4.5
Turbine electric generators	X	X	X	4.1-4.5
Turbine/centrifugal compressor	X	X	X	4.1-4.5
COMBUSTION SOURCES – Mobile Sources				4.6
Other company vehicles	X	X	X	4.6
Planes/helicopters	X	X	X	4.6
WASTE GAS DISPOSAL				5.0
Flares	X	X	X	5.1
Catalyst and thermal oxidizers	X			5.2
Incinerators	X	X	X	5.2
VENTED SOURCES – Process Vents				
Dehydration processes			X	6.3.8
Dehydrator Kimray pumps			X	6.3.8
Gas treatment processes	X		X	6.5.2
VENTED SOURCES – Other Venting				
Gas sampling and analysis			X	6.3, 6.8
Storage tanks			X	6.3.9
Loading/unloading/transit			X	6.7.2
Pneumatic devices			X	6.8.1
Chemical injection pumps			X	6.3.7
VENTED SOURCES – Maintenance/Turnarounds				
Compressor blowdowns			X	6.4.3
Compressor starts			X	6.4.6
Compressor station blowdowns			X	6.5.5
Pig traps and drips			X	6.6
Vessel blowdown			X	6.4
Pipeline blowdowns			X	6.8.2
VENTED SOURCES – Non-routine Activities				
Metering and Pressure Regulating (M&R) station upsets			X	6.8.2

Pressure relief valves (PRVs)			X	6.8.2
Pipeline dig-ins			X	6.6
Fire suppression				6.14
FUGITIVE SOURCES				7.0
Pipeline leaks			X	7.3
Process equipment leaks			X	7.3
Wastewater treatment			X	7.5
Air conditioning/refrigeration				7.6
INDIRECT SOURCES				8.0
Electricity imports	X	X	X	8.1
Process heat/steam imports	X	X	X	8.1

Footnotes:
X Indicates if CO_2, CH_4, or N_2O emissions may result from the source.

2.2.7 Enhanced Oil Recovery (EOR)

Crude oil production in the U.S. can include up to three distinct phases: primary, secondary, and tertiary (or enhanced) recovery. Only about 10 % of a reservoir's original oil in place is typically produced during primary recovery. Secondary recovery techniques extend a field's productive life generally resulting in the recovery of 20 to 40 % of the original oil in place. Tertiary recover, or enhanced oil recovery (EOR), techniques offer prospects for ultimately producing 30 to 60 %, or more, of the reservoir's original oil in place. Three major categories of EOR have been found to be commercially successful to varying degrees:

– *Thermal recovery*, involves the introduction of heat such as the injection of steam to lower the viscosity, or thin, the heavy viscous oil, and improves its ability to flow through the reservoir.

– *Gas injection*, uses gases such as natural gas, nitrogen, or carbon dioxide (CO_2) that expand in the reservoir and push additional oil to a production wellbore, or other gases that dissolve in the oil to lower its viscosity and improves its flow rate.

– *Chemical injection*, can involve the use of long-chained molecules called polymers to increase the effectiveness of water floods, or detergent-like surfactants.

CO_2 capture and geological injection refers to the chain of processes used to collect or capture a CO_2 gas stream, transport the CO_2 to a producing field, and inject the CO_2 into a geological formation[2]. This technique can be used to enhance oil recovery and ultimately for long-term isolation of CO_2 from the atmosphere.

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[2] For the purpose of this API *Compendium,* geological storage reservoirs explicitly exclude ocean sequestration.

Table 2-10 provides an indicative list of sources that contribute to GHG emissions from all phases of EOR activities, including separation and reuse of CO_2 as well as long term geological storage.

2.2.7.1 Separation and Reuse

The CO_2 used for EOR can originate from naturally-occurring reservoirs, or from capturing CO_2 streams from industrial applications such as natural gas processing, fertilizer, ethanol, and hydrogen plants. In order to maximize efficiency and make CO_2-EOR economically feasible there is a need to build-in into the production process a CO_2 recycling process for extracting the CO_2 from the production fluids. Three different methods include:

– *Amine gas sweetening process*, where the process for removing CO_2 from the production fluids include an initial physical absorption followed by the reaction of the basic amines with the dissolved gas.

– *Membrane separation process*, where the membrane separation capacity is based on the differences in physical or chemical interactions between gases and a membrane material, which is the reason why one component passes through the membrane faster than another.

– *Ionic liquids* are molted salts that are liquid even at temperature below 100 °C. Ionic liquids properties (such as conductivity, density, viscosity, gas solubility and others) can be tuned by varying the structure of the component ions to obtain desired solvent properties. Ionic liquids are considered to have high CO_2 capture capacity, high solubility in water, thermal stability, negligible vapor pressure, tunable physic-chemical characteristic and low toxicity.

In the capture step, CO_2 is separated from other gaseous products, compressed to facilitate efficient transportation, and when necessary, conditioned for transport (e.g., by dehydration). Captured CO_2 is then transported from the point of capture to the injection and/or storage site. Pipelines are the most common method for transporting CO_2; however, bulk transport of CO_2 by ship, truck, and rail occurs on a much smaller scale. Once at the injection site, the CO_2 may be additionally compressed and then injected into the producing reservoir.

Emissions from CO_2-EOR activities may occur during each of the phases. The operations associated with the capture phase require the use of energy (fossil fuel consumption and/or purchased electricity), resulting in combustion and/or indirect emissions. Vented and fugitive emissions may result from equipment used as part of the capture process. A small amount of emissions may also be released in the form of residual (uncaptured) CO_2 and CH_4. Transportation-related process losses may occur either as fugitive equipment leaks or as evaporative losses during maintenance, emergency releases, intermediate storage, and loading/offloading. Combustion or indirect emissions will also occur from energy consumption to compress and move the CO_2 between the capture and injection locations. Storage emissions include vented, fugitive, combustion and indirect emissions from equipment and associated energy requirements at the injection site. In addition, emissions may result from physical leaks from the storage site; uncaptured CO_2 co-produced with oil and/or gas, and enhanced hydrocarbon recovery operations.

Nitrous oxide and CH_4 emissions may also occur from the operation of combustion-driven equipment and purchased electricity.

2.2.7.2 Geological Storage

Carbon dioxide can be injected and retained in geologic structural and stratigraphic traps. Injection of CO_2 in deep geological formations prevents them from being emitted to the atmosphere. The process is based on technologies that have been developed for and applied by, the oil and gas industry. Well-drilling technology, injection technology, computer simulation of storage reservoir dynamics and monitoring methods can potentially be adapted from existing applications to meet the needs of geological storage. Beyond oil and gas production techniques, there are other successful underground injection practices – including natural gas storage, acid gas disposal and deep injection of liquid wastes

Just as there are certain places where oil, gas and natural CO_2 has been geologically trapped and stored in the subsurface, there will be underground reservoirs where CO_2 captured from power plants and industrial facilities can be safely and securely stored.

Potential risks from geological storage may arise from leaking injection wells, abandoned wells, leakage across faults and ineffective confining layers. Leakage of CO_2 could potentially degrade the quality of groundwater, damage some hydrocarbon or mineral resources, and have lethal effects on plants and sub-soil animals.

Release of CO_2 back into the atmosphere could also create local safety concerns. Avoiding or mitigating these impacts require careful site selection, effective regulatory oversight, an appropriate monitoring program that provides early warning that the storage site is not functioning as anticipated and implementation of remediation methods to stop or control CO_2 releases.

Table 2–10. Potential Greenhouse Gas Emission Sources by Sector: Enhanced Oil Recovery (EOR)

EOR (and Geological Storage)	**CO_2**	**N_2O**	**CH_4**	**Section**
COMBUSTION SOURCES – Stationary Devices				4.0
Boilers/steam generators	X	X	X	4.1-4.5
Dehydrator reboilers	X	X	X	4.1-4.5
Heaters/treaters	X	X	X	4.1-4.5
Fire pumps	X	X	X	4.1-4.5
Internal combustion (IC) engine generators	X	X	X	4.1-4.5
Reciprocating compressors	X	X	X	4.1-4.5
Turbine/centrifugal compressors	X	X	X	4.1-4.5
Turbine electric generators	X	X	X	4.1-4.5
COMBUSTION SOURCES – Mobile Sources				4.6
Marine, road or railroad tankers	X	X	X	4.6
Other company vehicles	X	X	X	4.6
Planes/helicopters	X	X	X	4.6
WASTE GAS DISPOSAL				5.0
Flares	X	X	X	5.1
Incinerators	X	X	X	5.2
VENTED SOURCES – Process Vents				
Dehydration processes	X		X (*)	6.3.8
Dehydrator Kimray pumps	X		X (*)	6.3.8
Gas sweetening processes	X		X (*)	6.3
VENTED SOURCES – Other Venting				
Intermediate storage	X		X (*)	6.9
Storage tanks	X		X (*)	6.3.9
Loading/unloading/transit	X		X (*)	6.3, 6.7.2
Pneumatic devices	X		X (*)	6.3.6
Chemical injection pumps	X		X (*)	6.3.7
VENTED SOURCES – Maintenance/Turnarounds				
Maintenance	X		X (*)	6.9
Gas sampling and analysis	X		X (*)	6.3, 6.8
Compressor blowdowns	X		X (*)	6.4.3
Compressor starts	X		X (*)	6.4.6
Pipeline blowdowns	X		X (*)	6.6, 6.8.2
Vessel blowdown	X		X (*)	6.4
VENTED SOURCES – Non-routine Activities				
Emergency releases	X		X (*)	6.9
Fire suppression				6.14
FUGITIVE SOURCES				7.0
Well leakage	X		X (*)	7.2
Equipment and pipeline leaks	X		X (*)	7.2, 7.3
Wastewater treatment	X		X (*)	7.5
Air conditioning/refrigeration				7.6
Fugitive emissions from ships	X		X (*)	NA
Physical leakage from geological formations	X		X (*)	NA
INDIRECT SOURCES				8.0
Electricity imports	X	X	X	8.1

Footnotes:
X Indicates if CO_2, CH_4, or N_2O emissions may result from the source.
* Significance of these sources depends on the CH_4 concentration and source-specific emission rate.

2.2.8 Crude Oil Transportation

The crude oil transportation segment consists of the movement of crude oil from the production segment to refineries. A list of indicative emission sources for crude oil transportation are shown in Table 2-11. Emission sources include loading and unloading of tank trucks, rail cars, and marine vessels; and transit losses from truck, marine, rail, and pipeline transportation.

Transportation emissions generally result from either losses of the material being transported or from combustion emissions from the motive forces used to transport the material. Product losses may occur either as fugitive equipment leaks or as evaporative losses during loading, unloading, and storage operations. In terms of GHG emissions, only CH_4 emissions result from product losses. The primary potential for CH_4 emissions is from handling 'live' crude oil (crude oil which has not yet reached atmospheric pressure) and associated gas. Table 2-11 addresses transportation of crude oil and other liquid products. However, most refined products and 'weathered' crude oil do not contain CH_4.

Emissions of CO_2 and significantly smaller quantities of N_2O occur in transportation due to combustion of fuels in IC engines, steam boilers on marine vessels, and turbines on gas compressors. It is also possible to have small amounts of unburned CH_4 emissions when natural gas is used to fire the IC engines or turbines.

In addition, SF_6 emissions may occur if SF_6 is used as a tracer gas to detect pipeline leaks. On a CO_2 equivalent basis, these may be a large emission source for some pipeline operations.

Table 2–11. Potential Greenhouse Gas Emission Sources by Sector: Crude Oil Transportation

CRUDE OIL TRANSPORTATION	**CO_2**	**N_2O**	**CH_4**	**Section**
COMBUSTION SOURCES – Stationary				4.0
Reciprocating compressors	X	X	X	4.1-4.5
Turbine electric generators	X	X	X	4.1-4.5
Turbine/centrifugal compressors	X	X	X	4.1-4.5
Heaters	X	X	X	4.1-4.5
Fire pumps	X	X	X	4.1-4.5
Internal combustion (IC) engine generators	X	X	X	4.1-4.5
Pumps	X	X	X	4.1-4.5
COMBUSTION SOURCES – Mobile Sources				4.6
Barges	X	X	X	4.6
Marine, road, or railroad tankers	X	X	X	4.6
Other company vehicles	X	X	X	4.6
Planes/helicopters	X	X	X	4.6

WASTE GAS DISPOSAL				5.0
Catalyst and thermal oxidizers	X	X		5.2
Incinerators	X	X		5.2
Vapor combustion units	X	X	X	5.2
VENTED SOURCES – Process Vents				
Storage tanks			X	6.3.9
Loading/unloading/transit			X	6.3, 6.7.2
Pneumatic devices			X	6.3.6
VENTED SOURCES – Maintenance/Turnarounds				
Pump station maintenance			X	6.4.6
VENTED SOURCES – Non-Routine Activities				
Breakout/surge tanks			X	6.10
Fire suppression				6.14
FUGITIVE SOURCES				7.0
Pipeline leaks			X	7.3
Process equipment leaks			X	7.3
Wastewater treatment	X		X	7.5
Air conditioning/refrigeration				7.6
Leak detection (SF_6 Emissions)				7.6
INDIRECT SOURCES				8.0
Electricity imports	X	X	X	8.1
Process heat/steam imports	X	X	X	8.1

Footnotes:
X Indicates if CO_2, CH_4, or N_2O emissions may result from the source.

2.2.9 Refining

The refining segment consists of all refinery sites that take in crude and produce finished products, such as gasoline. The refining process includes many distillation steps that separate petroleum hydrocarbons into narrower boiling ranges. There are also a number of refining processes in which hydrocarbons react, such as cracking, coking, reforming, alkylation, and isomerization. Hydrogen is often manufactured to support increased hydroprocessing to remove sulfur from petroleum products. Petrochemicals may be manufactured on the refinery site, some by separation and concentration of naturally occurring chemicals in the petroleum and others by reaction to form new materials. Refinery sites may also include manufacturing of lubricating oils, specialty oils, and asphalt.

Table 2-12 provides a list of potential GHG emission sources for the refining segment. Greenhouse gas emissions from refining occur primarily from combustion of fuels to provide the energy needed for the refining processes. Carbon dioxide emissions from boilers, process heaters, turbines, flares, and incinerators are the primary GHG emissions. Nitrous oxide emissions also result from these sources, but in quantities much smaller than those of CO_2.

When these combustion sources are fired with natural gas or refinery fuel gas, there may also be trace quantities of unburned CH_4 emissions.

The natural gas system, and potentially the refinery fuel gas system, are the only process streams within the refinery with potentially significant CH_4 concentrations. Fugitive CH_4 emissions may result from the piping and components associated with these systems and the combustion equipment fired by these fuels. Results from an API study on fugitive emissions from refinery fuel gas systems indicate that these emissions appear to be negligible.[3] The results from this study are presented in Appendix E.

A number of specialized process vents also may contribute GHG emissions. Some potential process vents include the fluid catalytic cracker (FCC) regenerator/CO boiler vent, cokers, hydrogen plant vents, and other catalyst regeneration. The FCC vent is primarily a source of CO_2 emissions, although there could be some unburned CH_4 if supplemental fuel is fired in a CO boiler. The hydrogen plant vent is primarily a source of CO_2 emissions, as are other catalyst regeneration vents.

Table 2–12. Potential Greenhouse Gas Emission Sources by Sector: Refining

REFINING	CO_2	N_2O	CH_4	Section
COMBUSTION SOURCES – Stationary Devices				4.0
Boilers/steam generators	X	X	X	4.1-4.5
Heaters	X	X	X	4.1-4.5
Fire pumps	X	X	X	4.1-4.5
Internal combustion (IC) engine generators	X	X	X	4.1-4.5
Pumps	X	X	X	4.1-4.5
Reciprocating compressor s	X	X	X	4.1-4.5
Turbine electric generators	X	X	X	4.1-4.5
Turbine/centrifugal compressor	X	X	X	4.1-4.5
Coke calcining kilns	X	X	X	4.1-4.5
COMBUSTION SOURCES – Mobile Sources				4.6
Company vehicles	X	X	X	4.6
Tanker trucks	X	X	X	4.6
Barges	X	X	X	4.6
WASTE GAS DISPOSAL				5.0
Flares	X	X	X	5.1
Catalyst and thermal oxidizers	X			5.2
Incinerators	X	X	X	5.2
VENTED SOURCES – Process Vents				
Sulfur recovery units	X			6.5.2, 6.11.6
Catalytic cracking	X			6.11.1
Catalytic reforming	X			6.11.3

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[3] Methane emissions data gathering and analyses were conducted for two refineries: a small simple refinery and a larger, more complex refinery. The estimated CH_4 fugitive emissions represent about 0.11% of the total GHG inventory for the small/simple refinery and about 0.19% of the GHG inventory for the large/complex refinery.

Catalyst regeneration	X			6.11.1
Steam methane reforming (hydrogen plants)	X			6.11.3
Delayed coking	X			6.11.2
Flexi-coking	X			6.11.6
Asphalt production			X	6.11.4
Thermal cracking	X			6.11.6
VENTED SOURCES – Other Venting				
Storage tanks				6.10
Pneumatic devices				6.3.6
VENTED SOURCES – Maintenance/Turnarounds				
Compressor starts				6.4.6
Equipment/process blowdowns				6.4.6
Heater/boiler tube decoking	X			6.11
VENTED SOURCES – Non-routine Activities				
Emergency shut down (ESD)				6.11.6
Pressure relief valves (PRVs)				6.3-6.4
Fire suppression				6.14
FUGITIVE SOURCES				7.0
Fuel gas system leaks			X	7.4
Other process equipment leaks				7.4
Sludge/solids handling				7.5
Wastewater collection and treating	X		X	7.5
Air conditioning/refrigeration				7.6
INDIRECT SOURCES				8.0
Electricity imports	X	X	X	8.1
Process heat/steam imports	X	X	X	8.1

Footnotes:
X Indicates if CO_2, CH_4, or N_2O emissions may result from the source.

2.2.9.1 Retail and Marketing of Petroleum Liquids

The retail and marketing segment includes company-owned retail operations and support to customer fueling operations. A list of potential GHG emission sources is provided in Table 2-13.

Evaporative emissions of hydrocarbons may occur during fuel transfer or pumping activities, but the concentration of CH4 or other GHGs is negligible in the refined products as shown by the compositions presented in Appendix E. Therefore, there generally are no significant GHG emissions from these activities. Methane emissions may result from process equipment leaks associated with LNG or compressed natural gas (CNG) marketing. Indirect emissions associated with onsite electricity usage are a source of CO_2, N_2O, and CH_4 emissions.

Table 2–13. Potential Greenhouse Gas Emission Sources by Sector: Retail and Marketing of Petroleum Liquids

RETAIL AND MARKETING	**CO_2**	**N_2O**	**CH_4**	**Section**

COMBUSTION SOURCES - Stationary				4.0
Boilers/steam generators	X	X	X	4.1-4.5
Heaters	X	X	X	4.1-4.5
COMBUSTION SOURCES – Mobile Sources				4.6
Marine tankers	X	X	X	4.6
Other company vehicles	X	X	X	4.6
Railroad tankers	X	X	X	4.6
Road tankers	X	X	X	4.6
WASTE GAS DISPOSAL				5.0
Thermal oxidizers	X			5.2
VENTED SOURCES				
Service station storage tanks				6.3, 6.10
VENTED SOURCES – Non-routine Activities				
Fire suppression				6.14
FUGITIVE SOURCES				7.0
Process equipment leaks				7.4
Air conditioning/refrigeration				7.6
INDIRECT SOURCES				8.0
Electricity usage	X	X	X	8.1

Footnotes:
X Indicates if CO_2, CH_4, or N_2O emissions may result from the source.

2.3 Related Industry Segments Description

2.3.1 Petrochemical Manufacturing

For some companies, operations to produce or manufacture chemicals derived from petroleum-based products are separate from refining operations. The sources of GHG emissions from petrochemical manufacturing, shown in Table 2-14, are similar to those of the refining segment.

Table 2–14. Potential Greenhouse Gas Emission Sources by Sector: Petrochemical Manufacturing

PETROCHEMICAL MANUFCTURING	**CO_2**	**N_2O**	**CH_4**	**Section**
COMBUSTION SOURCES – Stationary Devices				4.0
Boilers/steam generators	X	X	X	4.1-4.5
Heaters	X	X	X	4.1-4.5
Fire pumps	X	X	X	4.1-4.5
Internal combustion (IC) engine generators	X	X	X	4.1-4.5
Pumps	X	X	X	4.1-4.5
Reciprocating compressor drivers	X	X	X	4.1-4.5
Turbine electric generators	X	X	X	4.1-4.5
Turbine/centrifugal compressor drivers	X	X	X	4.1-4.5
COMBUSTION SOURCES – Mobile Sources				4.6
Company vehicles	X	X	X	4.6
WASTE GAS DISPOSAL				5.0
Flares	X	X	X	5.1
Catalyst and thermal oxidizers	X			5.2

Incinerators	X	X	X	5.2
VENTED SOURCES – Process Vents				
Catalyst regeneration	X			6.11
Steam methane reforming (hydrogen plants)	X			6.11
Chemical production	X	X	X	6.12
VENTED SOURCES – Other Venting				
Storage tanks			X	6.3, 6.10
Loading racks			X	
Pneumatic devices				6.3.6
VENTED SOURCES – Maintenance/Turnarounds				
Compressor starts				6.4.6
Equipment/process blowdowns				6.4.6
Heater/boiler tube decoking				6.11
VENTED SOURCES – Non-routine Activities				
Emergency shut down (ESD)				6.3-6.4
Pressure relief valves (PRVs)				6.3-6.4
Fire suppression				6.14
FUGITIVE SOURCES				7.0
Fuel gas system leaks			X	7.4
Other process equipment leaks				7.4
Sludge/solids handling				7.5
Wastewater collection and treating	X		X	7.5
Air conditioning/refrigeration				7.6
INDIRECT SOURCES				8.0
Electricity imports	X	X	X	8.1
Process heat/steam imports	X	X	X	8.1

Footnotes:
X Indicates if CO_2, CH_4, or N_2O emissions may result from the source.

Fossil fuel combustion is the most significant source of GHG emissions from chemical manufacturing, primarily resulting in CO_2 emissions. Trace quantities of N_2O emissions may also occur. Different operating conditions associated with specific petrochemical units, such as the high operating temperatures of olefin units, may result in higher N_2O combustion emissions than observed at refinery processes. Trace quantities of CH_4 also might be released from combustion equipment as a product of incomplete fuel combustion.

As in refineries, when natural gas or plant fuel gas is used to fuel the combustion devices, CH_4 emissions may result from fugitive sources associated with system piping or the combustion equipment itself. Vented and fugitive emissions may also result where significant concentrations of CH_4 are present in other process streams. In some circumstances, CH_4 may be used in petrochemical facilities for purposes other than combustion, such as tank and process vessel blanketing.

Small amounts of GHGs are released during the production of some petrochemicals. This API *Compendium* provides CH_4 emission factors associated with the production of five chemicals: carbon black, ethylene, ethylene dichloride, styrene, and methanol, based on national GHG inventory data (EPA, 2009). In addition, N_2O emission factors are provided for nitric oxide production and adipic acid production.

2.3.2 Minerals and Mining Operations

This segment includes the operation of mines and quarries primarily engaged in mining, mine site development, and preparing metallic and nonmetallic minerals, including coal. The term "mining" is used broadly to include ore extraction, quarrying, and beneficiating (e.g., crushing, grinding, screening, washing, and separating) customarily done at the mine site.

While CBM operations, discussed in Section 2.2.3, are considered another method of producing natural gas, this segment consists of minerals and mining operations where natural gas entrained in the produced minerals or located in the surrounding strata is not recovered. Table 2-15 provides a checklist of emission sources associated with this specialized industry segment.

A significant source of GHG emissions from mining operations is combustion emissions (CO_2 and trace amounts of CH_4 and N_2O). The operations associated with extraction and beneficiation are primarily mechanical and require the use of energy, either generated onsite or imported. Heat may also be required for some mining processes. Combustion emissions also result from the fuel consumed to operate mobile mining equipment. These sources exist for any type of mining operation.

Table 2–15. Potential Greenhouse Gas Emission Sources by Sector: Minerals and Mining Operations

MINERALS AND MINING OPERATIONS	CO_2	N_2O	CH_4	Section
COMBUSTION SOURCES – Stationary Devices				4.0
Boilers/steam generators	X	X	X	4.1-4.5
Heaters	X	X	X	4.1-4.5
Fire pumps	X	X	X	4.1-4.5
Internal combustion (IC) engines	X	X	X	4.1-4.5
Turbines	X	X	X	4.1-4.5
COMBUSTION SOURCES – Mobile Sources				4.6
Mining equipment	X	X	X	4.6
Other company vehicles	X	X	X	4.6
Site preparation, construction, and excavation	X	X	X	4.6
WASTE GAS DISPOSAL				5.0
Flares	X	X	X	5.1
Catalytic oxidizers	X			5.2
Incinerators	X	X	X	5.2

VENTED SOURCES – Process Vents				
Surface mining			X	
Ventilation and degasification			X	
VENTED SOURCES – Other Venting				
Water tanks				6.3.9
Coal seam drilling and well testing				6.2.4
Coal-handling				6.2
VENTED SOURCES – Non-routine Activities				
Fire suppression				6.14
FUGITIVE SOURCES				7.0
Equipment and pipeline leaks	X		X	7.2
Wastewater treatment			X	7.5
Air conditioning/refrigeration				7.6
INDIRECT SOURCES				8.0
Electricity imports	X	X	X	8.1
Process heat/steam imports	X	X	X	8.1

Footnotes:
X Indicates if CO_2, CH_4, or N_2O emissions may result from the source.

For coal mining, three types of activities release CH_4 to the atmosphere: underground mining, surface mining, and coal handling processes. Where mining gases are not recovered, CH_4 emissions from underground coal mines can be significant. Ventilation and degasification systems are used in underground mining to reduce CH_4 concentrations to safe levels by exhausting CH_4 to the atmosphere. Surface coal mining also releases CH_4 to the atmosphere as the coal is exposed, though the emissions are generally much lower than from underground mines. Finally, a portion of the CH_4 retained in the coal after mining may be released to the atmosphere during processing, storage, and transport.

Methane emissions from non-coal mining and mineral operations can occur through the same mechanics as those described for coal mining if CH_4 deposits are present.

Evaporative emissions of hydrocarbons may occur during fuel transfer or pumping activities, but the concentration of CH_4 or other GHGs is negligible in the refined products as shown by the compositions presented in Appendix E. Therefore, there generally are no significant GHG emissions from these activities. Methane emissions may result from process equipment leaks associated with LNG or compressed natural gas (CNG) marketing. Indirect emissions associated with onsite electricity usage are a source of CO_2, N_2O, and CH_4 emissions.

2.3.3 Energy Generation

Oil and gas industry operations are energy intensive, requiring steady supplies of electricity and often process heat, steam, or cooling. Steam is also used in enhanced oil recovery or enhanced coal bed methane production. A petroleum company may own and operate energy generation facilities to supply electricity and steam for these operations.

The sources of GHG emissions for energy generation operations are shown in Table 2-16. Combustion emissions of CO_2, and to a lesser extent N_2O and CH_4, result from the burning of fossil fuels to operate turbines, boilers, or compressors. Where natural gas is used to generate energy, emissions of CH_4 may result from process vents and fugitive sources, though these emissions are generally small compared to the combustion sources.

Table 2–16. Potential Greenhouse Gas Emission Sources by Sector: Electricity and Heat/Steam Generation

ELECTRICITY AND HEAT/STEAM GENERATION	CO_2	N_2O	CH_4	Section
COMBUSTION SOURCES - Stationary				4.0
Turbine electric generators	X	X	X	4.1-4.5
Boilers/steam generators	X	X	X	4.1-4.5
Internal combustion (IC) engine generators	X	X	X	4.1-4.5
COMBUSTION SOURCES – Mobile Sources				4.6
Company vehicles	X	X	X	4.6
VENTED SOURCES				6.0
Natural gas venting (maintenance on fuel line to natural gas fuel sources)	X		X	
VENTED SOURCES – Other Venting				
Fire suppression				6.14
FUGITIVE SOURCES				7.0
Natural gas equipment leaks (natural gas fuel line)	X		X	7.2
Air conditioning/refrigeration				7.6

Footnotes:
X Indicates if CO_2, CH_4, or N_2O emissions may result from the source.

As mentioned previously, SF_6 may be used as an insulator in electrical transmission and distribution systems. Fugitive and process vent emissions of SF_6 can occur from leaks or service activities on gas-insulated substations, circuit breakers, and other switchgear. Fugitive emissions of SF_6 can escape from gas-insulated equipment through seals, especially from older equipment. Sulfur hexafluoride can also be released during equipment manufacturing, installation, servicing, and disposal. Despite the very high global warming potential of SF_6, the quantities released as a result of oil and gas industry operations generally are very small.

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Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Natural Gas and Oil Industry

Section 3 – Technical Considerations

November 2021

Table of Contents

List of Tables

3.0
TECHNICAL CONSIDERATIONS

3.1 Overview

In general, emissions for a particular source are the product of the source-specific emission factor (EF) and the activity factor (AF). An inventory is the sum of all of the emissions for a particular facility or company:

$$\text{Emission Inventory} = \sum_{i=1}^{\#\,\text{sources}} \text{EF}_i \times \text{AF}_i \qquad \text{(Equation 3-1)}$$

where

Emissions Inventory = total emissions for a company or facility;
EF_i = emission factor for source *i*; and
AF_i = activity factor for source *i*.

Throughout this document it is important to note assumptions and conventions used in defining the emission factors. The listing below highlights some of the key areas where error can be introduced into the computation if conventions are not addressed properly.

- Standard Gas Conditions—When converting from a volume basis to a mass basis for a gas stream, the standard conditions used in this document are 14.696 pounds per square inch (psia) and 60 degrees Fahrenheit (°F) (equivalent to 101.325 kilo-Pascals absolute (kPaa) and 15.6 degrees Celsius (°C) in metric units). This is equivalent to 379.48 standard cubic feet (scf)/lb-mole (836.62 scf/kg-mole) or 23,690 cubic centimeters (cm^3)/g-mole.
- Heating Value Specifications—When converting between fuel volume and energy, HHV or gross calorific value is the preferred convention. However, LHV or net calorific values are also reported and used in some calculations.
- Units—Throughout this document, units are presented in the same convention used in the referenced source. This enables the user to easily check for updates from the referenced sources. Each emission factor is then also reported in terms of tonnes[1] per unit of activity, where the unit of activity is expressed in both the International System of Units (SI units) and U.S. customary units (USC). Conversion factors are provided in Table 3-4 if other units are desired.

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[1] Metric tonne = 1000 kg = 2204.62 lb.

- Fuel Combustion—Fuel properties in terms of heating values and carbon content are provided for a variety of fuels in commerce. Carbon dioxide emissions associated with the combustion of fossil fuels or refined products are based on the conversion of 100% of the fuel carbon to CO_2.

These and other considerations are more thoroughly discussed in the subsections that follow.

3.2 Emission Sources

Emissions of GHG in the oil and gas industry typically occur from one of the following general source classes: 1) combustion sources, including both stationary devices and mobile equipment; 2) waste gas disposal 3) process emissions and vented sources; 3) equipment leak sources; and 4) indirect sources. Some pieces of equipment, such as compressors, may emit under multiple classes − fugitive emissions when pressurized, vented emissions when depressurized for maintenance, and combustion emissions from the driver engines during normal operations. Tables 2-1 through 2-13, shown in Section 2, provide a detailed list of the types of potential emission sources associated with each of the general source classes discussed further in the following subsections.

3.2.1 Combustion

Combustion of carbon-containing fuels in stationary equipment such as engines, burners, and heaters results in the formation of CO_2 due to the oxidation of carbon. Emissions resulting from the combustion of fuel in transportation equipment (i.e., vessels, barges, ships, railcars, and trucks) that are included in the inventory are also categorized as combustion sources. Very small quantities of N_2O may be formed during fuel combustion by reaction of nitrogen and oxygen. Methane may also be released in exhaust gases as a result of incomplete fuel combustion, also refered to as the ‘methane slip’.

3.2.2 Waste Gas Disposal

The disposal of waste gas is characterized by the destruction of waste gas using flares, incinerators, and vapor oxidizers. Waste gas results from episodic venting, blowdowns, and pipeline purging events that would otherwise be vented to the atmosphere.

3.2.3 Process Emissions and Vented Sources

Process emissions and vented sources occur as releases resulting from normal operations, maintenance and turnaround activities, and emergency and other non-routine events. These include sources such as crude oil, condensate, oil, and gas product storage tanks; blanket fuel gas from produced water or chemical storage tanks; loading/ballasting/transit sources, and loading racks; as well as equipment such as compressors, chemical injection pumps and pneumatic devices that release GHGs (CH_4 and potentially CO_2) as part of their operation.

3.2.3.1 Emissions from routine operations

Routine operation emission sources include process vents which are a subcategory of vented sources and defined as those sources that produce emissions as a result of some form of chemical transformation or processing step. Examples of these sources include dehydration, gas sweetening, hydrogen plants (often referred to as steam methane reformers), naphtha reformers, catalytic cracking units, delayed cokers, coke calciners, and others. These sources are generally specific to the particular industry segment.

3.2.3.2 Emissions from periodic operations

Process emissions also result from periodic operations including maintenance, startup and turnaround activities. Maintenance and turnaround activities may require the depressurization of equipment and may result in vented emissions. Similarly, GHG emissions may result from equipment startup activities or from purging equipment prior to repressurization. Examples of other periodic operations classified as venting sources are well workovers, compressor turn-arounds, pipeline pigging operations, liquids unloading and heater/boiler tube decoking.

3.2.3.3 Emissions from unplanned operations

Other releases included as vented emission sources are non-routine releases from emergency or pressure relieving equipment such as emergency shutdowns (ESD) or emergency safety blowdowns (ESB), pressure relief valves (PRV), and breakout/surge tanks (described in Section 5.7.4).

3.2.4 Equipment Leak Sources

Fugitive equipment leak emissions are unintentional releases from piping components and leaks at sealed surfaces, as well as from underground pipeline leaks. Fugitive equipment leak emissions are usually low-volume leaks of process fluid (gas or liquid) from sealed surfaces, such as packing and gaskets, resulting from the wear of mechanical joints, seals, and rotating surfaces over time. Specific equipment leak emission source types include various components and fittings such as valves, connectors, pump seals, compressor seals, agitator seals, PRVs, instrument systems or sample systems. Fugitive equipment emissions also include non-point evaporative sources such as from wastewater treatment, pits, and impoundments.

3.2.5 Indirect Sources

Indirect emissions are emissions that are a consequence of activities of the reporting company but which result from sources owned or controlled by another party (IPIECA, 2011). This category includes emissions from the combustion of hydrocarbon fuels to generate electricity, heat, steam, or cooling, where this energy is imported or purchased.

3.3 Greenhouse Gases

This document is focused on CO_2, CH_4, and N_2O GHG emissions because these are the most prevalent GHGs emitted from oil and gas industry operations. However, while the API *Compendium* provides emission estimation methods for all six internationally recognized GHGs or classes of GHGs (CO_2, CH_4, N_2O, SF_6, HFCs, and PFCs), this should not imply that all of the GHGs are necessarily significant.

Carbon dioxide is primarily emitted from combustion sources, but may also be emitted from gas production, processing, refining, and CCS operations through some vented and fugitive sources. This is particularly important in operations using or processing CO_2-rich field gas. For these non-combustion sources, the potential for emitting CO_2 will depend on the CO_2 concentration associated with the emission source, as well as design and operating practices at facilities. The concentration of CO_2 in commercial natural gas is generally small (< 2% by pipeline specifications), such that vented and fugitive emissions associated with its use are small compared to emissions produced from combustion. However, vented and fugitive CO_2 emissions from CCS operations may be more significant than those from natural gas systems, but still small compared to CO_2 combustion emissions.

Methane emissions can result from any or all of the emission sources described in Section 3.2. Methane is emitted when natural gas is emitted from fugitive equipment leak sources or when natural gas is vented directly during maintenance or emergency procedures. Methane is also found in exhaust gases as a result of incomplete fuel combustion.

Nitrous oxide is produced both naturally, through various biological reactions in the soil and in water, and anthropogenically through industrial, waste management, and agricultural activities. With respect to oil and gas industry operations, trace amounts of N_2O may be formed from reactions between nitrogen and oxygen that occur during stationary or mobile source combustion. The quantity of N_2O formed during combustion varies based on the fuel, equipment, and pollution control device (e.g., catalytic converters installed to reduce motor vehicle emissions can increase N_2O emissions). Depending on the facility type (i.e. compressor station or gas plant) and the proliferation (and model/type) of reciprocating engines at a particular upstream facility, N_2O emissions can be more than 2% of the total facility GHG emissions inventory, on a CO_2e basis. As indicated in Section 8, N_2O emissions contribute less than 1% of a refinery's overall GHG inventory (on a CO_2e basis).

Air conditioning (mobile and stationary), refrigeration (including large process equipment such as chillers), and fire suppression equipment are potential sources of HFC and PFC emissions. Sulfur hexafluoride is most often used for circuit breaker applications in the electric power industry, but may also be used as a tracer gas for pipeline leak detection.

3.3.1 Global Warming Potentials

Greenhouse gas inventories are often reported in terms of Carbon Dioxide Equivalents (CO_2e), in which all of the GHGs are converted to an equivalent basis relative to their "global warming potential" (GWP). The GWP is a measure of a compound's radiative efficiency, or the compound's ability to trap heat, over a certain lifetime in the atmosphere, relative to the effects of the same mass of CO_2. The CO_2e value also takes into account the likelihood of indirect effects from other GHG precursers or compounds formed. While relatively constant, occasionally GWPs are adjusted slightly as scientific understanding of radiative forcing, atmospheric lifetime, and indirect effects improves. Emissions expressed in equivalent terms highlight the contribution of the various gases to the overall inventory for the purposes of accounting emissions. Therefore, GWP is a useful statistical weighting tool for comparing the heat trapping potential of various gases.

Table 3-1 presents the currently accepted GWP values associated with various compounds recognized as contributing to the greenhouse effect on a 100-year basis (Intergovernmental Panel on Climate Change (IPCC), 2013). According to the IPCC, the 100-year GWPs have an uncertainty of ±35 percent (IPCC, 2007b). The appropriate selection of GWP lifetime for accounting purposes is an area of debate among politicians. For CH_4 and N_2O, the time interval chosen can have a significant impact on accounting outcomes because there is a large difference between the lifetime of CH_4 and N_2O (approximately 12.2 years and 120 years, respectively) and the effective lifetime of CO_2 (200-250 years)[2]. In certain studies, the 20-year GWPs may be appropriate, however, currently, the parties to the United Nations Framework Convention on Climate (UNFCCC) have agreed to base GWPs on a 100-year time horizon (IPCC, 2013)[3].

The UNFCCC updates the GWP values periodically as new information becomes available. The IPCC published the Third Assessment Report (TAR) in 2001 (IPCC, 2001), the Fourth Assessment Report (AR4) in 2007 (IPCC, 2007b) and the Fifth Assessment Report (AR5) in 2013 (IPCC, 2013). All three reports present new GWP values based on improved understanding of the radiative forcing calculations and response function of CO_2. Although the 100-year GWPs were updated by successive IPCC reports, the 100-year values from the Second Assessment Report (SAR) (IPCC, 1996) were applicable through the first commitment period (2008-2012)[4]. For the second commitment period (2012-2019) AR4 100-year GWPs were applicable, and starting in 2020, under the Paris Agreement, AR5 is applicable [5,6]. The SAR, AR4 and AR5 100-year GWPs are the values applied in the API *Compendium*, as shown in Table 3-1.

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[2] For example, using the recommended GWP and selecting a time period of 50 years, the CH_4 GWP would be approximately 34, compared to a GWP of 6.5 for a 500-year integration interval.

[3] The IPCC reports including the most recent Fifth Assessment Report include the 20-year GWPs as well as the 100-year GWPs.

[4] This is consistent with UNFCCC reporting guidelines, which require reporting of GHG emissions and reductions using 100-year GWP values that have been identified by IPCC and adopted by the Conference of Parties (COP) (UNFCCC, 2002).

[5] In 2011, the UNFCCC COP as part of the Kyoto Protocol adopted the revised GWPs from AR4 for the second commitment period.

[6] The Ad Hoc Working Group on the Paris Agreement (APA) decided in December 2018 to adopt the 100-year GWP values from AR5 for anthropogenic emissions starting in 2020.

For comparison, Table 3-1 also includes the GWPs presented in the AR4.

Table 3-1. Greenhouse Gas and Global Warming Potentials

Gas	**Recommended GWP (UNFCCC, 2002) applicable through 2012**	**IPCC Revised GWP (IPCC AR4, 2007) applicable after 2012 through 2019**	**IPCC Revised GWP (IPCC AR5, 2014) applicable after 2019**
CO_2	1	1	1
CH_4 [a]	21	25	28
N_2O	310	298	265
Hydrofluorocarbons (HFCs)			
HFC-23	11,700	14,800	12400
HFC-32	650	675	677
HFC-41	150	97 [b]	116
HFC-125	2,800	3,500	3170
HFC-134	1,000	1,100 [b]	1120
HFC-134a	1,300	1,430	1300
HFC-143	300	330 [b]	328
HFC-143a	3,800	4,470	4800
HFC-152		43 [b]	16
HFC-152a	140	124	138
HFC-161		12 [b]	4
HFC-227ea	2,900	3,220	3350
HFC-236cb		1,300 [b]	1210
HFC-236ea		1,200 [b]	1330
HFC-236fa	6,300	9,810	8060
HFC-245ca	560	640 [b]	716
HFC-245fa		1,030	858
HFC-43-10mee	1,300	1,640	804
HFC-365mfc		794	1650
Perfluorinated compounds			
CF_4	6,500	7,390	6630
C_2F_6	9,200	12,200	11100
C_3F_8	7,000	8,830	8900
$c\text{-}C_4F_8$	8,700	10,300	9540
C_4F_{10}	7,000	8,860	9200
C_5F_{12}	7,500	9,160	8550
C_6F_{14}	7,400	9,300	7910
$C_{10}F_{18}$		>7,500	7190
NF_3		17,200	17400
SF_6	23,900	22,800	9200
SF_5CF_3		17,700	17400

Table 3-1. Greenhouse Gas and Global Warming Potentials, continued

Gas	Recommended GWP (UNFCCC, 2002) applicable through 2012	IPCC Revised GWP (IPCC AR4, 2007) applicable after 2012 through 2019	IPCC Revised GWP (IPCC AR5, 2014) applicable after 2019
Fluorinated ethers			
HFE-125		14,900	12400
HFE-134		6,320	5560
HFE-143a		756	523
HCFE-235da2		350	491
HFE-245cb2		708	654
HFE-245fa2		659	812
HFE-254cb2		359	301
HFE-347mcc3		575	530
HFE-347pcf2		580	889
HFE-356pcc3		110	413
HFE-449sl (HFE-7100)		297	421
HFE-569sf2 (HFE-7200)		59	57
HFE-43-10pccc124 (H-Galden 1040x)		1,870	2820
HFE-236ca12 (HG-10)		2,800	5350
HFE-338pcc13 (HG-01)		1,500	2910
Perfluoropolyethers			
PFPMIE		10,300	9710
Hydrocarbons and other compounds – Direct Effects			
Dimethylether		1	<1
Methylene chloride		8.7	9
Methyl chloride		13	12

Footnotes and Sources:

[a] The GWP of CH_4 includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.

[b] GWP values are taken from the IPCC Third Assessment Report (IPCC TAR, 2001). Values were not provided for these compounds in the Fourth Assessment Report.

3.3.2 Emissions Summaries

This document presents emission factors for CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6 for emission sources of interest to oil and gas industry operations. This section demonstrates how to use the GWP values as a convenient means of aggregating the combined effect of multiple GHGs. In developing emissions summaries, it is important to keep track of the actual mass emissions and sources of all the GHG compounds emitted, and report them individually, in addition to the weighted sum expressed as CO_2e. Also, the inventory should note the GWP value used in the aggregation and allow for revisions to the total emission estimate should the UNFCCC adopt revised GWPs.

Using GWP values, GHG emission estimates are often expressed in terms of CO_2e or Carbon Equivalents for final summation. Although any units of mass may be used to convert GHG emissions to these equivalent bases, the most widely recognized units are tonnes and million metric tonnes (MMT). The equations for calculating CO_2e and Carbon Equivalents are provided below.

$$CO_2\text{e, tonnes} = \sum_{i=1}^{\text{\# Greenhouse Gas Species}} (\text{tonnes}_i \times \text{GWP}_i) \qquad \text{(Equation 3-2)}$$

where

CO_2e = carbon dioxide equivalent emissions (tonnes);
tonnes_i = GHG emissions of pollutant *i* (tonnes); and
GWP_i = global warming potential of pollutant *i*, presented in Table 3-1 (tonnes CO_2e per tonne *i*).

$$\text{MMTCE} = CO_2\text{e, tonnes} \times \frac{\text{MW Carbon}}{\text{MW } CO_2} \times \frac{\text{MMTCE}}{10^6 \text{ tonnes Carbon}} \qquad \text{(Equation 3-3)}$$

where

MMTCE = Million Metric Tonnes of Carbon Equivalent, and
MW = molecular weight (MW Carbon = 12; MW CO_2 = 44).

Exhibit 3.1 demonstrates these calculations.

EXHIBIT 3.1: Sample Calculation for Carbon Equivalents

INPUT DATA:
A company's GHG inventory reported 8,800,000 tons/yr (i.e., short tons) of CO_2 emissions and 315,000 tons/yr of CH_4 emissions. What are the company's total CO_2 equivalent and carbon equivalent emissions for the GHG inventory (E_{CO_2e} and E_{CE})?

CALCULATION METHODOLOGY:
1. *Calculate* E_{CO_2e}. Equation 3-2 is used to calculate emissions in terms of CO_2e. As shown in Table 3-1, the GWP for CH_4 is 28, and the GWP for CO_2 is 1. (Note that Table 3-4 provides the tons to tonnes conversion factor.)

$$E_{\mathrm{CO_2}e} = \left[\left(\frac{8{,}800{,}000\ \mathrm{tons\ CO_2}}{\mathrm{yr}} \times \frac{1\ \mathrm{ton\ CO_2}e}{\mathrm{ton\ CO_2}}\right) + \left(\frac{315{,}000\ \mathrm{tons\ CH_4}}{\mathrm{yr}} \times \frac{28\ \mathrm{tons\ CO_2}e}{\mathrm{ton\ CH_4}}\right)\right] \times \frac{\mathrm{tonnes}}{1.10231\ \mathrm{tons}}$$

$$\underline{E_{\mathrm{CO_2}e} = 1.60\times10^7\ \mathrm{tonnes\ CO_2e/yr}}$$

EXHIBIT 3.1: Sample Calculation for Carbon Equivalents, continued

2. *Calculate* E_{CE}. Equation 3-3 is used to convert CO_2e emissions to carbon equivalents.

$$E_{\mathrm{CE}} = \frac{1.60\times10^7\ \mathrm{tonnes\ CO_2}e}{\mathrm{yr}} \times \frac{12\ \mathrm{tonnes\ C/mole\ C}}{44\ \mathrm{tonnes\ CO_2e/mole\ CO_2}e} \times \frac{\mathrm{mole\ C}}{\mathrm{mole\ CO_2}e} \times \frac{\mathrm{MMTCE}}{10^6\ \mathrm{tonnes\ C}}$$

$$\underline{E_{\mathrm{CE}} = 4.36\times10^6\ \mathrm{TCE/yr}}$$

Note that in the calculation above, the term "mole C/mole CO_2e" is shown to demonstrate the unit conversion. However, this term is not shown in Equation 3-3 or elsewhere in this document, as the term equates to 1.

3.4 Data Requirements

For many GHG emission sources, there are multiple options for determining the emissions, often with different accuracies. Table 3-2 illustrates the range of available options for estimating GHG emissions and associated considerations.

Table 3-2. Emission Estimation Approaches – General Considerations

Types of Approaches	General Considerations
Published emission factors	• Accounts for average operations or conditions • Simple to apply • Requires understanding and proper application of measurement units and underlying standard conditions • Accuracy depends on the representativeness of the factor relative to the actual emission source • Accuracy can vary by GHG constituents (i.e., CO_2, CH_4, and N_2O)
Equipment manufacturer emission factors	• Tailored to equipment-specific parameters • Accuracy depends on the representativeness of testing conditions relative to actual operating practices and conditions • Accuracy depends on adhering to manufacturers inspection, maintenance and calibration procedures • Accuracy depends on adjustment to actual fuel composition used on-site • Addition of after-market equipment/controls will alter manufacturer emission factors
Engineering calculations	• Accuracy depends on simplifying assumptions that may be contained within the calculation methods • May require detailed data
Process simulation or other computer modeling	• Accuracy depends on simplifying assumptions that may be contained within the computer model methods • May require detailed input data to properly characterize process conditions • May not be representative of emissions that are due to operations outside the range of simulated conditions
Monitoring over a range of conditions and deriving emission factors	• Accuracy depends on representativeness of operating and ambient conditions monitored relative to actual emission sources • Care should be taken when correcting to represent the applicable standard conditions • Equipment, operating, and maintenance costs must be considered for monitoring equipment
Periodic or continuous [a] monitoring of emissions or parameters [b] for calculating emissions	• Accounts for operational and source specific conditions • Can provide high reliability if monitoring frequency is compatible with the temporal variation of the activity parameters • Instrumentation not available for all GHGs or applicable to all sources • Equipment, operating, and maintenance costs must be considered for monitoring equipment

Footnotes and Sources:

[a] Continuous emissions monitoring applies broadly to most types of air emissions, but may not be directly applicable nor highly reliable for GHG emissions.

[b] Parameter monitoring may be conducted in lieu of emissions monitoring to indicate whether a source is operating properly. Examples of parameters that may be monitored include temperature, pressure and load.

As presented throughout the API *Compendium*, published emission factors are available from a variety of sources, including IPCC, EPA, Energy Information Administration (EIA), Gas Research Institute (GRI) and other widely available sources.

Where possible, this manual provides multiple estimation approaches for each category of emissions. Decision diagrams are provided to guide the user through the available options, where the choice of one approach over another is often dictated by the available data. Additional guidance on selecting estimation methods is provided in the *Guidelines* document (IPIECA, 2011). Ideally, the methodologies need to be consistent with the contribution of the particular emission source to the overall inventory. However, **methodologies required by regulations take precedence over the options provided in the decision trees or the *Guidelines* document.**

An emissions inventory is time dependent, reflecting conditions at the time the inventory is conducted. As processes or operations change, emission factor values may also change over time. A facility may change an equipment's emission factor by implementing control mechanisms, or may even eliminate a previous emission source through emission reduction activities. In addition, a published data source, such as AP-42 (EPA, 1995 with supplements), may revise emission factors based on new data. As an inventory is updated, emission factor approaches and sources should be reviewed for relevant updates to ensure their validity.

3.5 Data Assumptions

An emission factor represents an average emission rate for a given source, and is generally expressed as a mass or volume of emissions per source type or measure of activity related to the source. For example:

$$\frac{\text{scf } CH_4/\text{yr}}{\text{valve}} \text{ or } \frac{\text{g } CO_2}{\text{L diesel combusted}}$$

This API *Compendium* compiles emission factors from many different data sources. To allow the user to confirm or update an emission factor, detailed references are provided and the reported emission factors are maintained in the units convention from the referenced source. However, to simplify the use of these emission factors, the units convention adopted for this API *Compendium* is to express emission factors in terms of metric tonnes of emissions in the numerator, and express the denominator in terms of both U.S. customary units and SI units. Conversion factors are provided in Section 3.6.

When converting from a volume basis to a mass basis for a gas stream, the standard conditions used in this document are at 14.696 psia and 60°F[7] (or 101.325 kPaa and 15.6°C in metric). Using the ideal gas law:

$$PV = nRT \qquad \text{(Equation 3-4)}$$

where

P = pressure (psia or atm);
V = volume (ft^3, cm^3, or m^3);
n = number of moles;
R = gas constant = 10.7316 psi ft^3/lbmole degree Rankine (°R),
= 0.7302 atm ft^3/lbmole °R,
= 82.0574 atm cm^3/gmole Kelvin (K),
= 8.3145 Pa m^3/gmole K; and
T = absolute temperature (°R or K).

At standard conditions as defined for the API *Compendium*, 1 lbmole = 379.48 scf. In metric units, 1 gmole = 23,690 cm^3/gmol (23.690 m^3/kg-mole) at these same conditions.

Note that there are many different sets of standard or reference conditions, where "standard" often depends on the application or the industry convention. For example, physical properties of gases are often reported in terms of 0°C and 760 mm Hg (CRC, 1984). Table 3-3 provides molar volume conversions for commonly used gas conditions.

Table 3-3. Commonly Used Molar Volume Conversions [a]

	Molar Volume Conversion		
Temperature	**(scf/lb-mole)**	**(scf/kg-mole)**	**(m^3/kg-mole)**
0 °C	359.04	791.54	22.414
15 °C	378.75	835.01	23.645
20 °C	385.33	849.50	24.055
25 °C	391.90	864.99	24.465
60 °F [b]	379.48	836.62	23.690
68 °F	385.33	849.50	24.055
70 °F	386.79	852.72	24.146
73 °F	389.98	857.55	24.283

Footnotes and Sources:
[a] All molar volume conversions at 1 atm (14.696 psia).
[b] API *Compendium* standard conditions

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[7] 60°F and 14.696 psia are also consistent with standard conditions in American Society of Testing and Materials (ASTM) D3588-98 (1998, Reapproved 2017) and API Manual of Petroleum Measurement Standards, Chapter 14, Section 5 (January 1991, Reaffirmed March 2002).

To convert a volumetric rate from one set of standard conditions to another, the following equation can be used. Note that absolute temperatures (°R or K) are required for this equation.

$$V_2 = V_1\left[\frac{(P_1)(T_2)}{(P_2)(T_1)}\right] \qquad \text{(Equation 3-5)}$$

where

Subscript 1 = initial conditions for variable V, P, or T, and
Subscript 2 = new set of standard conditions for variable V, P, or T.

This conversion is demonstrated in Exhibit 3.2.

EXHIBIT 3.2: Sample Calculation for Converting between Sets of Standard Conditions

INPUT DATA:
The CH_4 emission factor for a pneumatic device was determined to be 345 scfd/device based on the standard conditions of 14.696 psia and 60°F. What is the emission factor at the EPA reference conditions of 101.3 kPa and 293 K (68°F), as shown in 40 CFR 60.2 and 63.2? What is the emission factor at 0°C and 760 mm Hg in both U.S. customary and SI units?

EXHIBIT 3.2: Sample Calculation for Converting between Sets of Standard Conditions, continued

CALCULATION METHODOLOGY:

1. *Calculate the emission factor at 101.3 kPa and 293K.* To convert the gas volumetric rate between different temperature and pressure conditions, the ideal gas law derivation shown in Equation 3-5 will be used. Because the ideal gas law requires absolute temperatures, the standard condition of 60°F must be converted to an absolute basis. In this case, the temperature will be converted from °F to K so it will be on the same basis as the new conditions. (Note that temperature conversions are provided in Section 3.6.)

$$T_{abs} = \frac{60°\text{F}-32}{1.8} + 273.15$$

$$\underline{T_{abs} = 288.7\ \text{K}}$$

The new emission factor is then calculated using Equation 3-5 for the new standard conditions:

$$\text{EF} = \left(345\,\frac{\text{scfd}}{\text{device}}\right) \times \left[\frac{(14.7\ \text{psia}) \times (293\ \text{K})}{(101.3\ \text{kPa}) \times \dfrac{(14.696\ \text{psia})}{(101.325\ \text{kPa})} \times (288.7\ \text{K})}\right]$$

$$\underline{\text{EF} = 350.3\,\frac{\text{scfd}}{\text{device}},\ \text{at 101.3 kPa and 293 K}}$$

2. *Calculate the emission factor at 760 mm Hg and 0°C.* As shown in calculation step 1 of this exhibit, the new temperature must be on an absolute basis, and the units at the current and new conditions must be the same for temperature and pressure, respectively. From Table 3-5, 0°C equals 273.15 K; from Table 3-4, 760 mm Hg equals 14.696 psia.

The new emission factor is calculated using Equation 3-5 for these new conditions.

$$\text{EF}_{\text{US}} = \left(345\,\frac{\text{scfd}}{\text{device}}\right) \times \left[\frac{(14.7\ \text{psia}) \times (273.15\ \text{K})}{(14.696\ \text{psia}) \times (288.7\ \text{K})}\right]$$

$$\underline{\text{EF}_{\text{US}} = 326.51\,\frac{\text{scfd}}{\text{device}},\ \text{at } 0^{\circ}\text{C and 760 mm Hg}}$$

EXHIBIT 3.2: Sample Calculation for Converting between Sets of Standard Conditions, continued

This result can be converted to SI units using the volumetric conversion factor provided in Table 3-4:

$$\mathrm{EF_{SI}} = 326.51 \frac{\text{scfd}}{\text{device}} \times \frac{\mathrm{m^3}}{35.3147\ \mathrm{ft^3}}$$

$$\mathrm{EF_{SI}} = 9.2456 \frac{\mathrm{m^3}}{\text{day-device}}, \text{ at } 0^{\circ}\mathrm{C} \text{ and } 760 \text{ mm Hg}$$

3.6 Conversions, Numeric Format, and Fuel Properties

3.6.1 General Units Conversions

API Manual of Petroleum Measurement Standards (MPMS) Chapter 15 specifies API-preferred units for quantities common to the oil and gas industry, and provides factors for converting customary units to the API-preferred metric units (API, 2001). The API-preferred units are consistent with metric practice, as defined by the General Conference on Weights and Measures and significant standards organizations (such as the American Society for Testing and Materials, the American National Standards Institute, and related technical societies). MPMS Chapter 15 served as the basis for the common unit conversion factors provided in Tables 3-3 through 3-6.

In Table 3-4, most of the conversion factors are shown with up to seven significant digits. Those shown to fewer than six significant figures are limited by the uncertainty of the measurement of the physical property. An asterisk (*) indicates that the conversion factor is exact, and any succeeding digits would be zeros.

Table 3-4. Conversion Factors

	Common US Units	API-Preferred SI Units	Other Conversions
Mass		1 kilogram	= 2.20462 pounds (lb) = 1000* grams (g) = 0.001 metric tonnes (tonne)
	1 pound (lb)	= 0.4535924 kilograms	= 453.5924 grams (g)
	1 short ton (ton)	= 907.1847 kilograms	= 0.4535924 metric tonnes (tonne) = 2000* pounds (lb)
	1 metric tonne (tonne)	= 1000* kilograms	= 2204.62 pounds (lb) = 1.10231 tons

Table 3-4. Conversion Factors, continued

	Common US Units	API-Preferred SI Units	Other Conversions
Volume		1 cubic meter (m^3)	= 1000 *liters (L) = 35.3147 cubic feet (ft^3) = 264.172 gallons = 6.28981 barrels (bbl)
	1 liter (L)		= 0.264172 gallons (gal)
	1 cubic foot (ft^3)	= 0.02831685 cubic meters (m^3)	= 28.31685 liters (L) = 7.4805 gallons
	1 gallon (gal)	3.785412×10^{-3} cubic meters (m^3)	= 3.785412 liters (L) = 0.006290 barrels (bbl)
	1 barrel (bbl)	= 0.1589873 cubic meters (m^3)	= 158.9873 liters (L) = 42* gallons (gal)
Length		1 meter (m)	= 3.28084 feet = 6.213712×10^{-4} miles
	1 kilometer (km)		= 0.6213712 miles
	1 inch (in)	= 0.0254* meters (m)	= 2.54* centimeters
	1 foot (ft)	= 0.3048* meters (m)	
	1 mile	= 1609.344* meters (m)	= 1.609344* kilometers
Area	Square feet (ft^2)	Acres	= 2.29568×10^{-5}
	Square meters (m^2)		= 2.47105×10^{-4}
	Square miles (mi^2)	Square kilometers (km^2)	= 5.58999
Power		1 Watt (W)	= 1* joule (J)/second = 9.47817×10^{-4} Btu/second = 1.34102×10^{-3} horsepower (hp)
	1 megawatt	10^6 Watts (W)	= 10^6* Joules/second = 1000* kilowatts (10^3 W)
	1 horsepower (hp)	= 745.6999 Watts (W)	= 0.7456999 kilowatts = 0.706787 Btu/second
Energy		1 Joule (J)	= 9.47817×10^{-4} Btu
		0.001 kilo Joules (kJ)	= 2.778×10^{-7} kilowatt-hour = 0.737562 foot-pounds$_{\text{force}}$
	1 horsepower-hour (hp-hr)	= 2.68452×10^6 Joules (J)	= 2544.43 Btu = 0.7456999 kilowatt-hour
	1 kilowatt-hour	= 3.6*$\times 10^6$ Joules (J)	= 3412.14 Btu = 1.34102 horsepower-hours = 3600* kilo-Joules
	1 Btu	= 1055.056 Joules (J)	= 3.93015×10^{-4} horsepower-hours = 2.93071×10^{-4} kilowatt-hours
	1 million Btu (10^6 Btu)	= 1.055056×10^9 Joules (J)	= 10 therms (thm) = 1.055056 giga-Joules (10^9 J) = 293.071 kilowatt-hours
	1 therm	= 1.055056×10^8 Joules (J)	= 100,000 Btu = 29.3071 kilowatt-hours
Pressure		1 kilo-Pascal (10^3 Pa)	= 9.869233×10^{-3} atmosphere (atm)
	1 atmosphere (atm)	= 101.325* kilo-Pascals (10^3 Pa)	= 14.696 pounds per square inch (psi) = 760 millimeters mercury (mm Hg) @ 0°C
	1 pound per square inch (psi)	= 6.894757 kilo-Pascals (10^3 Pa)	= 0.06804596 atmosphere (atm)

Table 3-4. Conversion Factors, continued

	Common US Units	API Preferred SI Units	Other Conversions
Heating Value			
Mass basis:	1 Btu/pound	= 2326.000 Joules/kilogram (J/kg)	
Volume basis:	1 Btu/cubic foot (Btu/ft^3)	= 37,258.95 Joules/cubic meter (J/m^3)	= 0.133681 Btu/gallon
Emission Factor:		1 kilogram/giga-Joule (kg/10^9 J)	= 2.32600 pound/million Btu (lb/10^6 Btu)
	1 pound/million Btu (lb/10^6 Btu)	= 0.429923 kilograms/giga-Joule (kg/10^9 J)	= 0.429923 tonnes/tera-Joule (tonnes/10^{12} J) = 429.923 grams/giga-Joule (g/10^9 J)
Barrels of Oil Equivalent (BOE)			
All Fuel Types	1 BOE	= 6.12x10^9 J	= 5.8x10^6 Btu
			= 2279.49 horsepower-hours
			= 1699.81 kilowatt-hours
Natural Gas	1 BOE	= 159.920 m^3	= 5,647.52 ft^3
Note: The BOE volume equivalent for natural gas was calculated by dividing the 5.8E+06 Btu/BOE by the heating value of natural gas (pipeline quality) from Table 3-8 (1,027 Btu/scf).			
Natural Gas Liquids	1 BOE	= 0.231327 m^3	= 1.455 bbl = 231.327 L = 61.11 gal = 8.16992 ft^3

Footnotes:
* indicates the conversion factor is exact; any succeeding digits would be zeros.
psig = Gauge pressure.
psia = Absolute pressure (note psia = psig + atmospheric pressure).

Table 3-5. Temperature Conversions

Degrees Fahrenheit (°F)	= 1.8 (degrees C) + 32
Degrees Rankine (°R)	= degrees F + 459.67
Degrees Celsius (°C)	= (degrees F – 32)/1.8
Kelvin (K)	= degrees C + 273.15

As shown in Table 3-6, the symbol associated with a particular unit or prefix can have multiple meanings depending on which system of units is used. The distinction between upper case and lower case letters used for the symbol is also important. To minimize confusion, this document expresses units numerically on a $\log_{10}$ basis (i.e., 10^x) or spells out the unit name.

Table 3-6. Unit Prefixes

SI Units		U.S. Designation	
Unit/Symbol	**Factor**	**Unit/Symbol**	**Factor**
peta (P)	10^{15}	quadrillion (Q)	10^{15}
tera (T)	10^{12}	trillion (T)	10^{12}
giga (G)	10^{9}	billion (B)	10^{9}
mega (M)	10^{6}	million (MM)	10^{6}
kilo (k)	10^{3}	thousand (k or M)	10^{3}
hecto (h)	10^{2}		
deka (da)	10^{1}		
deci (d)	10^{-1}		
centi (c)	10^{-2}		
milli (m)	10^{-3}		
micro (μ)	10^{-6}		
Nano (n)	10^{-9}		
Pico (p)	10^{-12}		

3.6.2 Numeric Format

This document does not maintain a fixed number of significant figures associated with the many numeric values presented. Where emission factors are cited, the API *Compendium* provides the same number of significant figures as reported in the emission factor source documents. This enables the user to easily compare values directly with the referenced sources as a check for updated emission factors. In general, a consistent number of significant figures is also reported for the emission factors converted to the unit convention adopted for the API *Compendium.*

Numeric round-off, reflecting an appropriate number of significant digits, is considered acceptable only at the final stage of creating an emissions inventory to prevent compounding inaccuracy through the various calculation steps. This practice is reflected in the example calculations in Section 8, where rounded-off results are presented in the summary tables.

3.6.3 Fuel Properties

Heating value describes the quantity of energy released when a fuel is completely combusted. The heating value per unit volume of a fuel is calculated as the volume- or mass-weighted average of the heat generated in the combustion of the individual components of the gas. While inert compounds (e.g., nitrogen, CO_2) have a zero heat of combustion, the heat of combustion of hydrocarbons per volume or mass increases with the addition of carbon atoms to the hydrocarbon chain. For example, a fuel that is rich in ethane and heavier components will have a greater HHV than a fuel that contains an increased amount of inert compounds and less ethane and heavier components. While a change in HHV is an indicator of composition change, it may not always be a sufficient index of combustion behavior since two fuels of the same heating values can have different compositions and combustion characteristics. However, when using pipeline quality natural gas as the fuel source, HHV may be used as an indicator of fuel carbon content and emissions index.

The difference between the HHV, also known as gross calorific value, and LHV, also referred to as the net calorific value, is based on whether the heat of combustion calculation uses the enthalpy of liquid water (HHV) or gaseous steam (LHV) for the water in the combustion products. The two heating values are related by the following equation:

$$\mathrm{HHV} = \mathrm{LHV} + \left(\mathrm{n}\bar{h}\right)_{H_2O} \qquad \text{(Equation 3-6)}$$

where

n = the number of moles of water in the products;
h = the enthalpy of vaporization of water at 25°C;
HHV = higher heating value, also referred to as gross calorific value, accounts for condensation of water vapor from the combustion process – the convention commonly used in EPA and U.S. Department of Energy (DOE) documents; and
LHV = lower heating value or net calorific value, which includes water in the vapor phase – the convention used by IPCC and other international sources.

In most cases, choosing between the use of heating values in terms of HHV or LHV is a matter of preference. The HHV convention is commonly used in the U.S. and Canada, while LHV is generally the preference outside North America. The API *Compendium* provides fuel heating values and energy-based emission factors in terms of both HHV and LHV. In general, emission factors taken from U.S. and Canadian references are in terms of HHV: factors from outside North America are in terms of LHV. Section 4.2 provides a detailed discussion of the method used throughout the API *Compendium* for conversion between LHV and HHV. The convention chosen will not impact the emission results, as long as the energy data and emission factors are on the same basis, either HHV or LHV. Errors occur when the conventions are not clearly identified and are combined (e.g., multiplying the energy associated with fuel use, reported on one basis, by an emission factor that is reported on the other basis).

Table 3-7 provides the molecular weight and heating values used in the API *Compendium* calculations for various hydrocarbon compounds[8]. The category "C9+" includes molecules with nine or more carbon atoms. Because "C9+" includes a group of compounds, an assumption must be made for the molecular weight based on specific knowledge of the liquid. The API *Compendium* assumes that the "C9+" is best represented by the C11 alkanes. Thus, the molecular weight for $C_{11}H_{24}$ will be used for "C9+."

Table 3-7. Hydrocarbon Molecular Weights and Gross Heating Values

Compound		Molecular Weight	Ideal Gross Heating Value, 60°F, 1 atm [a]	
			(Btu/scf)	(MJ/standard m^3)
Methane	CH_4	16.04	1009.7	37.620
Ethane	C_2H_6	30.07	1768.8	65.904
Propane	C_3H_8	44.10	2517.5	93.799
n-Butane	C_4H_{10}	58.12	3262.1	121.54
n-Pentane	C_5H_{12}	72.15	4009.6	149.39
n-Hexane	C_6H_{14}	86.18	4756.2	177.21
n-Heptane	C_7H_{16}	100.20	5502.8	205.03
Octanes	C_8H_{18}	114.23	6248.9 [b]	232.83
C9+ w/C_{11} MW	$C_{11}H_{24}$	156.31 (MW of $C_{11}H_{24}$)	8488.46 [c] (HHV of $C_{11}H_{24}$, gas)	316.27
Carbon Dioxide	CO_2	44.01	N/A	

Footnotes and Sources:
[a] Data taken from MPMS Chapter 14, Section 5, Table 1 (API, 2002), unless otherwise noted.
[b] Gas Processors Suppliers Association Engineering Databook (GPSA, 1987) Figure 23-2, for n- Octane.
[c] Perry's Chemical Engineers' Handbook (Perry, 1984) Table 3-207. (MW/HHV of C11H24, gas)

Table 3-8 provides heating values, in terms of both HHV and LHV, typical densities, and carbon contents by weight percent for some common fuel types. Note that using the carbon content of a liquid fuel (for example, gasoline) in the place of the carbon content of the vapor phase is a simplifying assumption that will overestimate emissions. In reality, the carbon content of the vapor phase will be lower than the carbon content of the liquid phase because vapors contain lighter hydrocarbons that are able to volatilize easier than heavier hydrocarbons.

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[8] Unless otherwise noted, data in Table 3-7 is taken from the Manual of Petroleum Measurement Standards (API, 2002); however, there are many other references that provide these data. Alternate information sources include: Perry's Chemical Engineers' Handbook, the Gas Processors Suppliers Association (GPSA) Engineering Databook, and ASTM International.

Table 3-8. Densities, Higher Heating Values, and Carbon Contents for Various Fuels

Fuel	Typical Density		Higher Heating Value		Lower Heating Value		Carbon, % by wt.
Acetylene	0.0686 lb/ft^3 [a]	1.10 kg/m^3	1.47×10^3 Btu/ft^3 [a]	5.49×10^7 J/m^3	1.33×10^3 Btu/ft^3	4.97×10^7 J/m^3	92.3
Asphalt and Road Oil	8.61 lb/gal [b]	1032.09 kg/m^3	6.64×10^6 Btu/bbl [b]	4.40×10^{10} J/m^3	6.30×10^6 Btu/bbl	4.18×10^{10} J/m^3	83.47 [b]
Aviation Gas	5.89 lb/gal [b]	705.74 kg/m^3	5.05×10^6 Btu/bbl [b]	3.35×10^{10} J/m^3	4.80×10^6 Btu/bbl	3.18×10^{10} J/m^3	85.00 [b]
Butane (liquid)	4.86 lb/gal	582.93 kg/m^3	4.33×10^6 Btu/bbl [b]	2.87×10^{10} J/m^3	4.11×10^6 Btu/bbl	2.73×10^{10} J/m^3	82.8 [b]
Coal, anthracite	No data [c]	No data	1.13×10^4 Btu/lb [c]	2.63×10^7 J/kg	1.07×10^4 Btu/lb	2.49×10^7 J/kg	No data [c]
Coal, bituminous	No data [c]	No data	1.19×10^4 Btu/lb [c]	2.78×10^7 J/kg	1.13×10^4 Btu/lb	2.64×10^7 J/kg	No data [c]
Crude Oil	7.29 lb/gal [b]	873.46 kg/m^3	5.80×10^6 Btu/bbl [b]	3.85×10^{10} J/m^3	5.51×10^6 Btu/bbl	3.66×10^{10} J/m^3	84.8 [b]
Distillate Oil (Diesel)	7.07 lb/gal [b]	847.31 kg/m^3	5.83×10^6 Btu/bbl [b]	3.87×10^{10} J/m^3	5.53×10^6 Btu/bbl	3.67×10^{10} J/m^3	86.34 [b]
Ethane (liquid)	3.11 lb/gal	372.62 kg/m^3	2.92×10^6 Btu/bbl [b]	1.94×10^{10} J/m^3	2.77×10^6 Btu/bbl	1.84×10^{10} J/m^3	80.0 [b]
Fuel Oil #4	7.59 lb/gal [d]	909.48 kg/m^3	6.01×10^6 Btu/bbl [d]	3.99×10^{10} J/m^3	5.71×10^6 Btu/bbl	3.79×10^{10} J/m^3	86.4 [d]
Isobutane	4.69 lb/gal	561.59 kg/m^3	4.16×10^6 Btu/bbl [b]	2.76×10^{10} J/m^3	3.95×10^6 Btu/bbl	2.62×10^{10} J/m^3	82.8 [b]
Jet Fuel	6.81 lb/gal [b]	815.56 kg/m^3	5.67×10^6 Btu/bbl [b]	3.76×10^{10} J/m^3	5.39×10^6 Btu/bbl	3.57×10^{10} J/m^3	86.30 [b]
Kerosene	6.83 lb/gal [b]	818.39 kg/m^3	5.67×10^6 Btu/bbl [b]	3.76×10^{10} J/m^3	5.39×10^6 Btu/bbl	3.57×10^{10} J/m^3	86.01 [b]
Lignite	No data [c]	No data	6.43×10^3 Btu/lb [c]	1.50×10^7 J/kg	6.11×10^3 Btu/lb	1.42×10^7 J/kg	No data [c]
LNG [m]		0.41 – 0.50 kg/m^3	1,1010.80 Btu/ft^3 [m]				
LPG [e]	See footnote e						
Lubricants	7.52 lb/gal [b]	900.70 kg/m^3	6.07×10^6 Btu/bbl [b]	4.02×10^{10} J/m^3	5.76×10^6 Btu/bbl	3.82×10^{10} J/m^3	85.80 [b]
Miscellaneous Product [f]	7.29 lb/gal [b]	873.46 kg/m^3	5.80×10^6 Btu/bbl [b]	3.85×10^{10} J/m^3	5.51×10^6 Btu/bbl	3.65×10^{10} J/m^3	85.49 [b]
Motor Gasoline [g]	6.20 lb/gal [b]	742.39 kg/m^3	5.25×10^6 Btu/bbl [b]	3.49×10^{10} J/m^3	4.99×10^6 Btu/bbl	3.31×10^{10} J/m^3	86.60 [b]
Natural Gas (processed)	0.042 lb/ft^3 [h]	0.6728 kg/m^3	1,020 Btu/ft^3 [h] 1,004 Btu/ft^3 1,027 Btu/ft^3 [c]	3.80×10^7 J/m^3 3.74×10^7 J/m^3 3.83×10^7 J/m^3	918 Btu/ft^3 903 Btu/ft^3 924 Btu/ft^3	3.42×10^7 J/m^3 3.37×10^7 J/m^3 3.44×10^7 J/m^3	76 wt% C [h]
Natural Gas (raw / unprocessed)			1,235 Btu/ft^3	4.60×10^7 J/m^3	1,111 Btu/ft^3	4.14×10^7 J/m^3	
Natural Gas Liquids (NGL) [e]	See footnote e						
Natural Gasoline [f]	5.54 lb/gal [b]	663.70 kg/m^3	4.62×10^6 Btu/bbl [b]	3.07×10^{10} J/m^3	4.39×10^6 Btu/bbl	2.91×10^{10} J/m^3	83.70 [b]
Pentanes Plus	5.54 lb/gal [b]	663.70 kg/m^3	4.62v10^6 Btu/bbl [b]	3.07×10^{10} J/m^3	4.39×10^6 Btu/bbl	2.91×10^{10} J/m^3	83.70 [b]
Petrochemical Feedstocks	5.95 lb/gal [b]	712.49 kg/m^3	5.25×10^6 Btu/bbl [b, j]	3.48×10^{10} J/m^3	4.99×10^6 Btu/bbl	3.31×10^{10} J/m^3	84.11 [b]
Petroleum Coke [f]	No data [b]	No data	6.02×10^6 Btu/bbl [b]	4.00×10^{10} J/m^3	5.72×10^6 Btu/bbl	3.80×10^{10} J/m^3	92.28 [b]

Table 3-8. Densities, Higher Heating Values, and Carbon Contents for Various Fuels, continued

Fuel	Typical Density		Higher Heating Value		Lower Heating Value		Carbon, % by wt.
Petroleum Waxes	6.76 lb/gal [b]	809.50 kg/m^3	5.54×10^6 Btu/bbl [b]	3.67×10^{10} J/m^3	5.26×10^6 Btu/bbl	3.49×10^{10} J/m^3	85.29 [b]
Propane (gas) [k]	0.12 lb/ft^3	1.90 kg/m^3	2,516.1 Btu/ft^3 [a]	9.37×10^7 J/m^3	2,314.9 Btu/ft^3 [a]	8.63×10^7 J/m^3	81.8 [b]
Propane (liquid)	4.22 lb/gal	505.61 kg/m^3	3.82×10^6 Btu/bbl [b]	2.54×10^{10} J/m^3	3.63×10^6 Btu/bbl	2.41×10^{10} J/m^3	81.8 [b]
Residual Oil #5	7.93 lb/gal [d]	950.22 kg/m^3	6.30×10^6 Btu/bbl [d]	4.18×10^{10} J/m^3 [d]	5.99×10^6 Btu/bbl	3.97×10^{10} J/m^3	88.7 [d]
Residual Oil #6 [l]	8.29 lb/gal [b]	992.98 kg/m^3	6.29×10^6 Btu/bbl [b]	4.17×10^{10} J/m^3 [b]	5.97×10^6 Btu/bbl	3.96×10^{10} J/m^3	85.68 [b]
Special Naphtha	6.46 lb/gal [b]	774.49 kg/m^3	5.25×10^6 Btu/bbl [b]	3.48×10^{10} J/m^3	4.99×10^6 Btu/bbl	3.31×10^{10} J/m^3	84.76 [b]
Still Gas	No data [b]	No data	6.00×10^6 Btu/bbl [b]	3.98×10^{10} J/m^3	5.70×10^6 Btu/bbl	3.78×10^{10} J/m^3	No data [b]
Unfinished Oils [f]	7.29 lb/gal [b]	873.46 kg/m^3	5.83×10^6 Btu/bbl [b]	3.87×10^{10} J/m^3	5.53×10^6 Btu/bbl	3.67×10^{10} J/m^3	85.49 [b]

All LHVs were derived from HHVs. To convert from HHV to LHV, the assumed conversion for gaseous fuels is LHV = (0.9) × (HHV); for solids or liquids the assumed conversion is LHV = (0.95) × (HHV). Note that the values presented in this table are taken from multiple sources. As a result, the inherent fuel properties and assumptions associated with each fuel may differ. Values in original source units are footnoted; additional values are derived from original source values.

Footnotes and Sources:

[a] Gas Processors Association, *Engineering Data Book*, Volume II, 1987.

[b] Energy Information Administration, *Documentation for Emissions of Greenhouse Gases in the United States 2006*, Tables 6-5 and 6-7, October 2008. Densities provided as API gravity or bbl/tonne and converted.

[c] U.S. Environmental Protection Agency (EPA), *Inventory of U.S. Greenhouse Gas Emissions and Sinks*: 1990-2007, Annexes, Table A-251, April 15, 2009.

[d] *North American Combustion Handbook*, Volume I: Combustion Fuels, Stoichiometry, Heat transfer, Fluid Flow, ISBN 0-9601596-2-2, Third Edition, Cleveland, Ohio, 1986.

[e] LPG and NGL are blends of multiple hydrocarbons (e.g., ethane, propane, isobutene), each with its own heat content, density and carbon content. Mixture properties should be calculated using the methods described in Section 3.6.4.

[f] Term defined in the Glossary.

[g] Motor gasoline includes conventional gasoline, all types of oxygenated gasoline (including gasohol), and reformulated gasoline, but excludes aviation gasoline.

[h] EPA AP-42, Section 1.4, *Natural Gas Combustion*, 1998.

[i] Canadian Association of Petroleum Producers (CAPP), *Calculating Greenhouse Gas Emissions*, Table 1-5, Canadian Association of Petroleum Producers, Publication Number 2003-03, April 2003.

[j] Parameters presented are for naphthas with a boiling temperature of less than 400° F. Petrochemical feedstocks with higher boiling points are assumed to have the same characteristics as distillate fuel.

[k] Calculated using methodology provided in *API Measurement of Petroleum Measurement Standards*, Chapter 14 - Natural Gas Fluids Measurement, Section 5 – Calculation of Gross Heating Value, Specific Gravity and Compressibility of Natural Gas Mixtures from Compositional Analysis, ANSI/API 14.5-1981, First Edition, January 1981, Reaffirmed March 2002.

[l] Values shown are for residual fuel, which is defined in the text of the reference document as No. 6 fuel oil.

[m] Heating value varies with origin. Value shown for Alaska in API LNG Operations Consistent Methodology for Estimating Greenhouse Gas emissions (API, 2015) Table 1.

Table 3-9 provides carbon contents for natural gas according to heating value ranges. Note that in the United States, pipeline quality natural gas has a HHV greater than 970 Btu/scf but less than 1,100 Btu/scf (EPA, 2009). Gas with heating values outside this range should be not be classified as natural gas, but could instead be classified as produced gas, refinery gas, associated gas, or process gas. Lower heating value gases tend to have a higher content of inert gases, while higher heating value gases tend to have a higher content of natural gas liquids, both of which affect the carbon content of the gas (EPA, 2009).

Table 3-9. Natural Gas Carbon Contents by Heating Value

Higher Heating Value	Carbon Content, g C/1000 BTU [a]	Higher Heating Value	Carbon Content, g C/1000 BTU [b]
GRI Full Sample [c]	14.51	1,100 to 1,125 Btu/scf	15.07
Greater than 1,000 Btu/scf	14.47	1,125 to 1,150 Btu/scf	15.09
1,025 to 1,035 Btu/scf	14.45	1,150 to 1,175 Btu/scf	15.15
975 to 1,000 Btu/scf	14.73	1,175 to 1,200 Btu/scf	15.27
1,000 to 1,025 Btu/scf	14.43	1,200 to 1,225 Btu/scf	15.38
1,025 to 1,050 Btu/scf	14.47	1,225 to 1,250 Btu/scf	15.52
1,050 to 1,075 Btu/scf	14.58	Greater than 1,250 Btu/scf	16.33
1,075 to 1,100 Btu/scf	14.65		
Weighted National Average [d]	14.47		

Footnotes and Sources:

[a] Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks*: 1990-2007, Annex A, Table A-38, April 15, 2009.

[b] Based on data from worldwide LNG operations and U.S. produced gas with high heating values. The gas compositions included in this analysis did not include H_2.

[c] The "GRI Full Sample" value represents the average of 6,743 samples of pipeline-quality natural gas from utilities and/or pipeline companies in 26 cities located in 19 states.

[d] The national average was weighted by applying the carbon content associated with the average heat content of natural gas consumed in each state by the portion of national natural gas consumption represented by that state.

3.6.4 Fuel Mixture Conversions

Fuel properties for mixtures vary, particularly for non-commercial fuels associated with diverse oil and gas industry operations. This section describes and illustrates how to estimate fuel mixture data from pure component data, how to convert a fuel composition from a weight basis to a molar basis, and how to convert between different sampling bases.

The weight percent composition of a mixture is converted to a mole percent composition by multiplying the individual weight percentages by the ratio of the molecular weight of the mixture to the individual molecular weights:

$$\text{Mole\%}_i = \text{Wt\%}_i \times \frac{\text{MW}_{\text{Mixture}}}{\text{MW}_i} \qquad \text{(Equation 3-7)}$$

where

Mole%$_i$ = molar or volume percent of constituent *i;*
Wt%$_i$ = weight or mass percent of constituent *i;*
MW$_{\text{Mixture}}$ = molecular weight of mixture; and
MW$_i$ = molecular weight of constituent *i.*

If complete speciation is available for the mixture, MW$_{\text{Mixture}}$ can be calculated as the weighted average of the individual molecular weights:

$$\text{MW}_{\text{Mixture}} = \frac{1}{100} \times \sum_{i=1}^{\#\text{compounds}} \left(\text{Mole\%}_i \times \text{MW}_i\right) \qquad \text{(Equation 3-8)}$$

Or, in terms of Wt%:

$$\text{MW}_{\text{Mixture}} = 100 \div \sum_{i=1}^{\#\text{compounds}} \frac{\text{Wt\%}_i}{\text{MW}_i} \qquad \text{(Equation 3-9)}$$

If complete speciation of the mixture is not available, MW$_{\text{Mixture}}$ can sometimes be obtained from chemical property tables that list data for common oil and gas fractions (e.g., gasoline, No.2 distillate, etc.). Molecular weight values used in the API *Compendium* calculations for various hydrocarbon compounds can be found in Table 3-7.

Exhibits 3.3 and 3.4 illustrate the conversion calculations between weight percent compositions and mole percent compositions.

EXHIBIT 3.3: Sample Calculation for Converting from Weight Percent to Mole Percent For Known Fuel Analysis

INPUT DATA:

A chemical analysis is taken for a liquid fuel sample. The analysis shows that the sample contains the following compounds on a weight basis. Molecular weights from Table 3-7 are also shown.

Compound	Weight %	Molecular Weight
Methane	0.5	16.04
Ethane	1.0	30.07
Propane	2.0	44.10
Butanes	3.0	58.12
Pentanes	7.0	72.15
Hexanes	10.0	86.18
Heptanes	25.0	100.20
Octanes	30.0	114.23
C9+	21.5	156.31

Convert the sample analysis to a mass basis.

CALCULATION METHODOLOGY:

The equation to convert from individual compound mole% to wt% (Equation 3-7) requires the molecular weight of the mixture ($MW_{Mixture}$), which is calculated using Equation 3-9:

$$MW_{Mixture} = 100 \div \left(\frac{0.5}{16.04} + \frac{1.0}{30.07} + \frac{2.0}{44.10} + \frac{3.0}{58.12} + \frac{7.0}{72.15} + \frac{10.0}{86.18} + \frac{25.0}{100.20} + \frac{30.0}{114.23} + \frac{21.5}{156.31} \right)$$

$$\underline{MW_{Mixture} = 97.64}$$

Equation 3-7 is then used to calculate the individual compound mole %. For example, for hexane:

$$Mole\%_{Hexane} = 10.0 \times \frac{97.64}{86.18}$$

$$\underline{Mole\%_{Hexane} = 11.33\%}$$

Repeating this calculation for the remaining compounds results in the mole% compositions shown below.

EXHIBIT 3.3: Sample Calculation for Converting from Weight Percent to Mole Percent For Known Fuel Analysis, continued

Compound	Weight %	Molecular Weight	Mole %
Methane	0.5	16.04	3.04
Ethane	1.0	30.07	3.25
Propane	2.0	44.10	4.43
Butanes	3.0	58.12	5.04
Pentanes	7.0	72.15	9.47
Hexanes	10.0	86.18	11.33
Heptanes	25.0	100.20	24.36
Octanes	30.0	114.23	25.64
C9+	21.5	156.31	13.43
Total	**100**		**100**

The previous example illustrates how to convert the weight fraction of compounds in a liquid fuel mixture to molar fractions. This methodology would also apply to solid and gaseous fuel mixtures. In gaseous mixtures, mole percents and volume percents are often used interchangeably when the mixture is assumed to be an ideal gas.

EXHIBIT 3.4: Sample Calculation for Converting from Weight Percent to Mole Percent For Unknown Fuel Analysis

INPUT DATA:
The molecular weight of a mixture is known to be 97.65 grams/gmole, and the concentration of only CH_4 is known (0.5 weight % CH_4). What is the mole % CH_4? To confirm the solution, recalculate the weight % CH_4 using the calculated mole%.

CALCULATION METHODOLOGY:
1. *Calculate the mole% CH_4.* The mole% CH_4 is calculated using Equation 3-7:

$$\text{Mole\%}_{CH_4} = \frac{0.5\text{ g }CH_4}{100\text{ g mixture}} \times \frac{\left(\dfrac{97.65\text{ g mixture}}{\text{gmole mixture}}\right)}{\left(\dfrac{16.04\text{ g }CH_4}{\text{gmole }CH_4}\right)} = \frac{0.0304\text{ gmole }CH_4}{\text{gmole mixture}}$$

$\underline{\text{Mole\%}_{CH_4} = 3.04\text{ mole \% }CH_4}$

EXHIBIT 3.4: Sample Calculation for Converting from Weight Percent to Mole Percent For Unknown Fuel Analysis, continued

2. *Confirm the solution.* If only the mixture molecular weight and CH_4 mole percent are known, the CH_4 weight % is calculated by re-arranging Equation 3-7:

$$\text{Wt.\%}_{CH_4} = \frac{3.04\text{ gmole }CH_4}{100\text{ gmole mixture}} \times \frac{\left(\dfrac{16.04\text{ g }CH_4}{\text{gmole }CH_4}\right)}{\left(\dfrac{97.65\text{ g mixture}}{\text{gmole mixture}}\right)} = \frac{0.00499\text{ g }CH_4}{\text{g mixture}}$$

$$\text{Wt.\%}_{CH_4} = 0.5\text{ wt. \% }CH_4$$

Gas composition and physical property data can be represented on several different bases, including as a wet or dry gas, or in an ideal or real state. Wet gas refers to the presence of liquid hydrocarbons and/or water in the gas. Natural gas at the wellhead is often referred to as wet for this reason. Dry gas refers to a lack of liquid hydrocarbons or water in the gas. Pipeline quality gas is often referred to as dry since the bulk of the liquid hydrocarbons and water have been removed. Ideal gas refers to a gas that follows the principles of the ideal gas law (particles have negligible volume and no intermolecular forces), which is adequate for many engineering calculations over a wide range of conditions.[9]

Gas properties can be converted between wet and dry, or ideal and real bases. Described below are the conversions for heating values.

Some methods for measuring heating values are based upon the gas being saturated with water (wet gas basis), while other methods are based upon the gas not having a significant amount of vapor (dry gas basis). If a water-saturated gas sample is analyzed on a dry gas basis, it must be converted to account for the fact that water has displaced some gas and thus has lowered the heating value. If the heating value of the mixture is known, Equation 3-10 can be used to determine the adjusted heating value.

$$HV_{wet} = (1\text{-}x_{liq})HV_{dry} \qquad \text{(Equation 3-10)}$$

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[9] At high pressures and low temperatures, all gases deviate from ideal behavior and more complex equations of state are needed.

where

HV_{wet} = ideal gas heating value of the mixture, per unit volume, on a wet gas basis;
x_{liq} = mole fraction of water or liquid hydrocarbons in the gas; and
HV_{dry} = ideal gas heating value of the mixture, per unit volume, on a dry gas basis.

Equation 3-11 is applied when the heating value of the wet gas mixture is not known. For this equation, water is not included in the N components of summation.

$$HV_{wet} = (1 - x_w) \sum_{i=1}^{N} x_i \, HV_{i,dry} \qquad \text{(Equation 3-11)}$$

where

N = number of components in the summation;
x_i = mole fraction of constituent *i* in the gas;
x_w = mole fraction of water or liquid hydrocarbons in the gas; and
$HV_{i,dry}$ = ideal gas gross heating value of constituent *i*, per unit volume, on a dry gas basis.

It is important to note that the equations above are sufficient for GHG emission estimation purposes and are commonly used for custody transfer conditions (ASTM, 2003). More detailed equations are available if it is necessary to account for the complete conversion for the effect of water on heating value, including the effect of relative humidity (ASTM, 2003). However, this added calculation complexity improves the accuracy of the estimates only slightly.

Exhibit 3.5 illustrates how to estimate the gas mixture gross heating value on a dry basis, and then how to convert it to a wet basis using the equations provided above.

EXHIBIT 3.5: Sample Calculation for Converting from Dry Gas Basis to Wet Gas Basis For Known Gas Analysis

INPUT DATA:
A chemical analysis is taken on a dry basis for a wet gas sample. The analysis shows that the sample contains the following compounds on a weight basis. Heating values from Table 3-7 are also shown. Calculate the heating value on a wet basis.

EXHIBIT 3.5: Sample Calculation for Converting from Dry Gas Basis to Wet Gas Basis For Known Gas Analysis, continued

Compound	**Mol Fraction**	**Heating Value (Btu/scf)**
Methane	2.99	1009.7
Ethane	3.19	1768.8
Propane	4.35	2517.5
Butanes	4.95	3262.1
Pentanes	9.30	4009.6
Hexanes	11.13	4756.2
Heptanes	23.94	5502.8
Octanes	25.19	6248.9
C9+	13.20	8488.46
Water	1.74	--

CALCULATION METHODOLOGY:
To adjust the heating value to a wet basis, the contribution of each compound towards the mixture's heating value ($x_i HV_{i,dry}$) must be calculated. This calculation is performed below, for methane:

$$\left[x_i HV_{i,dry}\right]_{Methane} = \frac{2.99}{100} \times 1009.7 \text{ Btu/scf}$$

$$\left[x_i HV_{i,dry}\right]_{Methane} = 30.16 \text{ Btu/scf}$$

Repeating this calculation for the remaining compounds results in the heating value contributions shown below.

Compound	**Mole Fraction**	**$x_i HV_i$ (Heating Value Contribution)**
Methane	2.99	30.16
Ethane	3.19	56.48
Propane	4.35	109.58
Butanes	4.95	161.54
Pentanes	9.30	373.09
Hexanes	11.13	529.48
Heptanes	23.94	1317.10
Octanes	25.19	1574.28
C9+	13.20	1120.12
Water	1.74	--

EXHIBIT 3.5: Sample Calculation for Converting from Dry Gas Basis to Wet Gas Basis For Known Gas Analysis, continued

The heating value is then adjusted to a wet basis using Equation 3-11.

$$HV_{wet} = (1-x_w)\sum_{i=1}^{N} x_i HV_{i,dry}$$

$$HV_{wet} = \left(1-\frac{1.74}{100}\right)\left[\begin{array}{l}30.16+56.48+109.58+161.54+373.09+529.48\\+1317.10+1574.28+1120.12\end{array}\right]$$

$$\underline{HV_{wet} = 2532.49 \text{ Btu/scf}}$$

Ideal gas heating values are calculated from the molar composition and ideal gas heating values of the components of the fuel. The heating value can then be adjusted based on Equation 3-12 using a compressibility factor, which is a measure of how much the real gas deviates from the ideal gas. A complete description of how to calculate the compressibility factor can be found in *Calculation of Gross Heating Value, Specific Gravity, and Compressibility of Natural Gas Mixtures from Compositional Analysis* (API, 2002).

$$HV_r = \frac{HV}{Z} \qquad \text{(Equation 3-12)}$$

where

HV = ideal gas heating value;
HV_r = real gas heating value; and
Z = compressibility factor, notes tables for CH_4 and CO_2 are provided in Perry's Chemical Engineer's Handbook Tables 3-172 and 3-166, respectively (Perry, 1984).

3.7 Emission Estimation Quality

Uncertainty is used to characterize the dispersion of values that could be reasonably attributed to a measured quantity (IPCC, 2000). Conducting an uncertainty analysis is recognized as an important step in prioritizing future work and improving the overall quality of an inventory (EPA, 2009). Data quality and the uncertainty associated with such data are of increasing importance when developing GHG emission inventories. The uncertainty intervals associated with emission rates, activity data or emission factors are characterized by the dispersion of the respective measurement values that were used to derive them initially. Therefore, estimating uncertainties in emission inventories is based on the characteristics of the variable(s) of interest (input quantity), as estimated from the applicable data set. Such uncertainties will depend both on the accuracy and representativeness of direct measurements, and the assumed probability distributions for the key parameters used for aggregating the overall emissions inventory.

The overall uncertainty associated with a GHG inventory is driven primarily by the uncertainty associated with the largest ("key") sources of emissions. Although very high levels of uncertainty may be associated with some sources, their overall impact on the uncertainty of entity-wide emissions, or that of a specific installation, may often be very small. In turn, the uncertainty associated with each individual source depends on the quality and availability of sufficient data to estimate emissions and/or on the ability to measure emissions and properly account for measurement variability.

This section provides a description of calculation approaches for statistical assessment of uncertainty and its aggregation (Section 3.7.1) to allow users to quantify the uncertainty associated with their own inventories. This section also addresses different methods of assessing data quality that are either based on calculated uncertainty intervals from raw measurement data (Section 3.7.2) such as for the GRI/EPA methane emissions study (Harrison, et al, 1996), or originally reported quality indicators for emission factors (Section 3.7.3). Calculated aggregated uncertainties for selected example facilities are provided in Section 8.

3.7.1 General Statistical Approach to Calculating Uncertainty

Uncertainties associated with GHG emission inventories are the result of three main processes:

1. Incomplete, unclear or faulty definitions of emission sources;
2. Natural variability of the process that produces the emissions; and
3. Models, or equations, used to quantify emissions for the process or quantity under consideration.

When assessing the process or quantity under consideration, uncertainties could be attributable to one or more factors such as: sampling, measuring, incomplete reference data, or inconclusive expert judgment. The uncertainty associated with total annual emissions is comprised of several components of uncertainty, of which measurement uncertainty is but one. To the extent that measurement and accounting errors can be minimized, such action will have a direct influence on reducing the overall uncertainty associated with emission inventories.

The goal of conducting a detailed uncertainty assessment is two fold:

1. Provide a quantitative assessment of the confidence intervals for the emissions calculated; and
2. Highlight areas of high uncertainty where targeted data collection efforts could lead to material improvement of the emission assessment.

This section provides a brief overview of statistical methods and concepts applicable to conducting an uncertainty assessment for a facility- or entity-wide GHG inventory. Additional details of the technical considerations and calculation methods, including calculation examples, are available in a separate API publication: *Addressing Uncertainty in Oil & Natural Gas Industry Greenhouse Gas Inventories: Technical Considerations and Calculation Methods* (referred to as the *Uncertainty Document*; API, 2009). Both in this section as well as the *Uncertainty Document* the statistical analysis of uncertainty is not viewed as a mean unto itself but as a tool for phasing-in data quality improvements.

Calculation Methods Basics

At the most basic level, a GHG inventory is comprised of calculated and estimated emissions from individual emission sources. Emission information typically is obtained either through direct on-site measurement of emissions, or the combination of measured or published emission factors and some measure of the activity that results in the emission (referred to as the activity factor). Emissions from multiple sources are then aggregated to produce the inventory. The quantification of the uncertainty associated with such calculations or estimates should be applied at the emission source level (or grouping of similar emission sources) and then propagated to the total inventory (as discussed in Section 2.5 of the *Uncertainty Document*).

An emission factor describes the emission rate associated with a given emission source. Emission factors may be either based on site-specific measurements or based on published values that were derived from averaging a variety of measurements. Activity factors are generally a measured quantity, such as a count of equipment or measure of fuel consumed. Sampling uncertainty, measurement uncertainty, and process variability are types of uncertainties that may apply to emission factors and activity factors.

Quantifying the uncertainty for a GHG inventory involves mathematically combining individual sources of uncertainty to establish an estimate of the overall uncertainty. The general steps for quantifying uncertainty are:

1) Determine uncertainty for activity data;

2) Determine uncertainty for emission factor data; and
3) Aggregate uncertainties.

There are four general equations for aggregating uncertainty that are used in this document and the *Uncertainty Document* for compiling the uncertainty associated with a GHG inventory.

Consider two quantities that can be measured: X and Y. The uncertainty for these values can be expressed on an absolute basis as $\pm U_X$ and $\pm U_Y$, respectively. Uncertainty may also be expressed on a relative basis, generally reported as a percentage:

$\pm 100\left(\frac{U_X}{\mathrm{X}}\right)\%$ or $\pm 100\left(\frac{U_Y}{\mathrm{Y}}\right)\%$, respectively.

Depending on the uncertainty propagation equation, the absolute or relative uncertainty value may be required. In addition, selection of the propagation equation also depends on whether the uncertainties associated with the individual uncertainty parameters are independent or correlated. The uncertainties in two quantities are considered independent if they were estimated by entirely separate processes and there was no common source of uncertainty. The correlation or covariance of uncertainty terms is addressed through an additional term in the propagation equations, discussed further below. Note that where more than two uncertainty parameters are related, a Monte Carlo simulation is recommended for aggregating the uncertainties (IPCC, 2000). Additional information on Monte Carlo simulations is provided by IPCC (IPCC, 2006).

Error Propagation for a Sum (or Difference)

Two potential equations are used for computing the total uncertainty from the addition or subtraction of two or more measured quantities. The selection between the two equations depends on whether or not the uncertainties associated with the measured quantities, X and Y, are correlated.

For uncertainties that are mutually independent, or uncorrelated (i.e., the uncertainty terms are not related to each other), the aggregated error is calculated as the "square root of the sum of the squares" using the absolute errors, as shown in Equation 3-13.

$$U(abs)_{X+Y+...+N} = \sqrt{U_X^2 + U_Y^2 + \ldots + U_N^2}$$

(Equation 3-13)

where, U(*abs*) refers to the absolute uncertainty.

The absolute uncertainty values are used in the equations, and the resulting aggregated uncertainty ($U(abs)_{X+Y+\ldots+N}$) is also on an absolute basis.

For two uncertainty parameters that are related to each other, the equation becomes:

$$U(abs)_{Correlated\ X+Y} = \sqrt{U_X^2 + U_Y^2 + 2r(U_X \times U_Y)}$$

(Equation 3-14)

where, r is the correlation coefficient between U_X and U_Y.

Error Propagation for a Product (or Quotient)

The equation for propagating uncertainties from the product or quotient of two or more measured and independent quantities is similar to Equation 3-13. However, in this case the relative uncertainties are used, as shown in Equation 3-15. When multiplied by 100, the resulting combined uncertainty ($U(Rel)_{X\times Y\times N}$) is expressed as a percentage.

$$U(rel)_{X\times Y\times\ldots\times N} = U(rel)_{X\div Y\div\ldots\div N} = \sqrt{\left(\frac{U_X}{X}\right)^2 + \left(\frac{U_Y}{Y}\right)^2 + \ldots + \left(\frac{U_N}{N}\right)^2}$$

(Equation 3-15)

Equation 3-16 is used to estimate the uncertainty of a product or quotient of two parameters (X and Y) where the uncertainties are correlated and positive values. Here also, relative uncertainty values are used in the equation and the resulting combined uncertainty is on a relative basis.

$$U(rel)_{Correlated\ X\times Y} = \sqrt{\left(\frac{U_X}{X}\right)^2 + \left(\frac{U_Y}{Y}\right)^2 + 2r\left(\frac{U_X}{X} \times \frac{U_Y}{Y}\right)}$$

(Equation 3-16)

Combining Uncertainties

It may be necessary to combine multiple uncertainty parameters associated with a single measured value, such as combining uncertainties for precision and bias. For uncertainty parameters that are independent, the combined uncertainty is calculated using the absolute uncertainties as shown in Equation 3-13. Similarly, for uncertainty parameters that are related to each other, Equation 3-14 applies.

Correlation Coefficient

The correlation coefficient, r, used in Equations 3-14 and 3-16, is a number between -1 and 1, which measures the linear relationship between the uncertainties of two measured parameters. The value of r is zero when the parameters are independent. As stated previously, once the uncertainty propagation exceeds two terms and covariance occurs, the use of the Monte Carlo approach is preferable.

For two terms that might be correlated, the uncertainties are plotted against each other. For the purpose of this discussion, U_X represents the uncertainties of one variable plotted along the x-axis, and U_Y represents the uncertainties of the second variable plotted on the y-axis. The correlation coefficient, r, is determined by a linear regression of the U_X and U_Y values.

If one suspects that the uncertainty parameters are correlated, but data are not available to plot or calculate the correlation coefficient, the following rule-of-thumb values could be applied, using expert judgment (Franzblau, 1958)[10]:

r = 0: no correlation, the data are independent;
r = ±0.2: weak correlation;
r = ±0.5: medium correlation;
r = ±0.8: strong correlation; and
r = ±1: perfect correlation, the data fall on a straight line.

Additional details are provided in the *Uncertainty Document*.

3.7.2 Confidence Intervals from GRI/EPA Study

The GRI (currently known as the Gas Technology Institute) and EPA conducted a study in the early to mid 1990s to quantify CH_4 emissions from the U.S. natural gas industry. A sampling program was designed to address uncertainty, bias, and accuracy calculations, with an inventory accuracy objective of 0.5% of U.S. natural gas production on the basis of a 90% confidence interval (Harrison, et. al., 1996). Details on the statistical methods employed by the GRI/EPA study can be found in the documents: *Methane Emissions from the Natural Gas Industry*, Volume 3: General Methodology and Volume 4: Statistical Methodology (Harrison, et. al., 1996; and Williamson, et. al., 1996).

Confidence intervals establish the lower and upper limits within which the true value of an estimated number might be found for a given probability level. For the emission factors derived

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[10] http://irp.savstate.edu/irp/glossary/correlation.html

from the GRI/EPA study, the confidence intervals were determined from a sample of measurements, and the relative uncertainty defined as the ratio of the calculated confidence interval and the sample mean. Mathematically, the relative uncertainty is expressed as:

$$U(rel) = \pm t \times \frac{s(x)/\sqrt{n}}{\bar{x}} \times 100\% \qquad \text{(Equation 3-17)}$$

where

$U(rel)$ = relative uncertainty;
t = student's t-distribution for "n-1" degrees of freedom, which gives a 95% confidence interval. This value is obtained from a standard table in most statistics books;
s(x) = standard deviation of the data set, calculated in Equation 3-18;
n = sample size for the set of data; and
$\bar{x}$ = mean (average) for the set of data.

$$s(x) = \sqrt{\frac{1}{n-1}\sum_{i=1}^{n}\left(x_i - \bar{x}\right)^2} \qquad \text{(Equation 3-18)}$$

where

$\bar{x}$ = mean (average) for the set of data;
x_i = i^th^ observation in the set of data; and
n = sample size for the set of data.

In Sections 5 and 6, confidence intervals are expressed in terms of uncertainty where emissions factors from the GRI/EPA study are cited. However, the values reported in this API *Compendium* have been updated to a 95% confidence interval to be more consistent with current statistical reporting practices. A 95% confidence interval indicates that there is a 5% chance that the true value falls outside the confidence interval.

3.7.3 Quality Ratings

EPA's AP-42 publication series and emission factor database (FIRE[11]) provide emission factor quality ratings. The *Introduction of the Compilation of Air Pollutant Emission Factors, Volume I:*

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[11] FIRE is the EPA's emission factor database. FIRE includes emission factors from AP-42 (including AP-42 supplements) and locating and estimating documents, as well as revoked emission factors. The latest version of FIRE (WebFIRE, December 2005) can be found online at: http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main, accessed January 13, 2009.

Stationary Point and Area Sources (EPA, 1995) and FIRE characterize emission factor ratings as follows:

A = Excellent. Emission factor is developed primarily from A and B-rated source test data[12] taken from many randomly chosen facilities in the industry population. The source category population is sufficiently specific to minimize variability.

B = Above average. Emission factor is developed primarily from A- or B-rated test data from a moderate number of facilities. Although no specific bias is evident, it is not clear if the facilities tested represent a random sample of the industry. As with the A rating, the source category population is sufficiently specific to minimize variability.

C = Average. Emission factor is developed primarily from A-, B-, and C-rated test data from a reasonable number of facilities. Although no specific bias is evident, it is not clear if the facilities tested represent a random sample of the industry. As with the A rating, the source category population is sufficiently specific to minimize variability.

D = Below average. Emission factor is developed primarily from A-, B- and C-rated test data from a small number of facilities, and there may be reason to suspect that these facilities do not represent a random sample of the industry. There also may be evidence of variability within the source population.

E = Poor. Factor is developed from C- and D-rated test data from a very low number of facilities, and there may be reason to suspect that the facilities tested do not represent a random sample of the industry. There also may be evidence of variability within the source category population.

U = Unrated. Emission factor is developed from source tests that have not been thoroughly evaluated, research papers, modeling data, or other sources that may lack supporting documentation. The data are not necessarily "poor," but there is not enough information to rate the factors according to the rating protocol. "U" ratings are commonly found in locating and estimating documents and FIRE rather than in AP-42.

The combustion emission factors reported in Section 4, which are taken from EPA's AP-42 publications, cite these ratings.

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[12] For descriptions of source test data ratings, see *Introduction to AP-42 Volume 1*, page 9 (EPA, 1995).

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Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Natural Gas and Oil Industry

Section 4 - Combustion Emissions Estimation Methods

November 2021

Table of Contents

List of Tables

List of Figures

4.0 COMBUSTION EMISSIONS ESTIMATION METHODS

This section addresses combustion emissions from stationary sources, mobile sources, and other miscellaneous combustion sources. The approaches presented here focus on fossil fuel-based combustion sources. Sources used to dispose of waste gases (e.g. flares, incinerators, oxidizers, etc.) are addressed in Section 5.

In addition to fossil fuels, fuels can also be produced from biomass or plant materials (hereafter referred to as "biogenic fuels". Emission factors for biogenic fuels are presented throughout this section. However, a separate discussion on biogenic fuels is presented in Section 4.7 because accounting for emissions from biogenic fuels requires special accounting. In addition, there is a fundamental difference between combusting fossil fuels and combusting biogenic fuels.

Carbon dioxide, CH_4, and N_2O are produced and/or emitted as a result of combustion. Combustion of hydrocarbons can be represented by the following general reaction, assuming complete combustion:

$$C_xH_yO_z + \left(x + \frac{y}{4} - \frac{z}{2}\right) O_2 \rightarrow (x)\ CO_2 + \left(\frac{y}{2}\right) H_2O \qquad \text{(Equation 4-1)}$$

where

x = stoichiometric coefficient for carbon;
y = stoichiometric coefficient for hydrogen; and
z = stoichiometric coefficient for oxygen.

Carbon dioxide emissions result from the oxidation of the hydrocarbons during combustion. Nearly all of the fuel carbon is converted to CO_2 during the combustion process, and this conversion is relatively independent of the fuel or firing configuration. Methane emissions may result from the incomplete combustion of the fuel, which is emitted as unburned CH_4. This is sometimes referred to in the literature as "methane slip" or "combustion slip". Incomplete combustion also results in other products such as carbon monoxide (CO) and volatile organic compounds (VOC)[1].

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[1] VOC excludes non-reactive hydrocarbons, such as methane and ethane.

For petroleum industry operations, N_2O is formed during combustion by a complex series of reactions. Because its formation is dependent upon many factors, N_2O emissions can vary widely from unit to unit, and even vary within the same unit for different operating conditions. Typically the conditions that favor formation of N_2O also favor CH_4 emissions; these CH_4 emissions also vary with the type of fuel and firing configuration. Overall, CH_4 and N_2O emissions from combustion sources are significantly less than CO_2 emissions, on a CO_2 equivalent basis. Methane and N_2O emissions for stationary combustion sources are calculated separately using emission factors.

Because emissions from combustion sources comprise such a large part of a GHG inventory, it is important to understand the accuracy of the data used in the calculations. For example, fuel measurement data can be taken from flow meters, the accuracy of which can be affected by calibrations, inspection, and maintenance. Fuel composition can vary over time so emissions calculated using carbon content may or may not be representative, depending on the frequency of the sampling data and the variability of the fuel's composition. The accuracy of calculated emissions depends on the accuracy of the input data. Table 4-1 illustrates the range of available options for estimating combustion GHG emissions and associated considerations.

Table 4-1. Emission Estimation Approaches – GHG and Source-Specific Considerations for Combustion Sources

Types of Approaches	CO_2 Emissions	CH_4, N_2O Combustion Emissions
Published emission factors	• Based on "average" fuel carbon content • Commodity fuels generally have consistent compositions	• Based on "average" equipment characteristics • Uncertainty is consistent with generally low contribution to overall emissions
Equipment manufacturer emission factors	• CO_2 emissions are related more to fuel type than equipment characteristics • Manufacturer published emission factors are based on engine type, air/fuel ratio, and fuel type	• Emissions are closely related to equipment characteristics
Engineering calculations	• Highly reliable for many emission sources but dependent on methodology used and assumptions made • May require detailed input data	• Limited application for oil and gas industry operations (e.g., flares)
Monitoring over a range of conditions and deriving emission factors		
Periodic or continuous monitoring of emissions or parameters for calculating emissions	• Generally not practical for oil and gas operations given the substantial number of emission sources	• Not practical given the number of emission sources and the low contribution to overall emissions

Figure 4-1 provides a decision tree for selecting a stationary combustion calculation approach for estimating CO_2 emissions for all stationary combustion sources except for waste gas disposal sources (see Section 5).

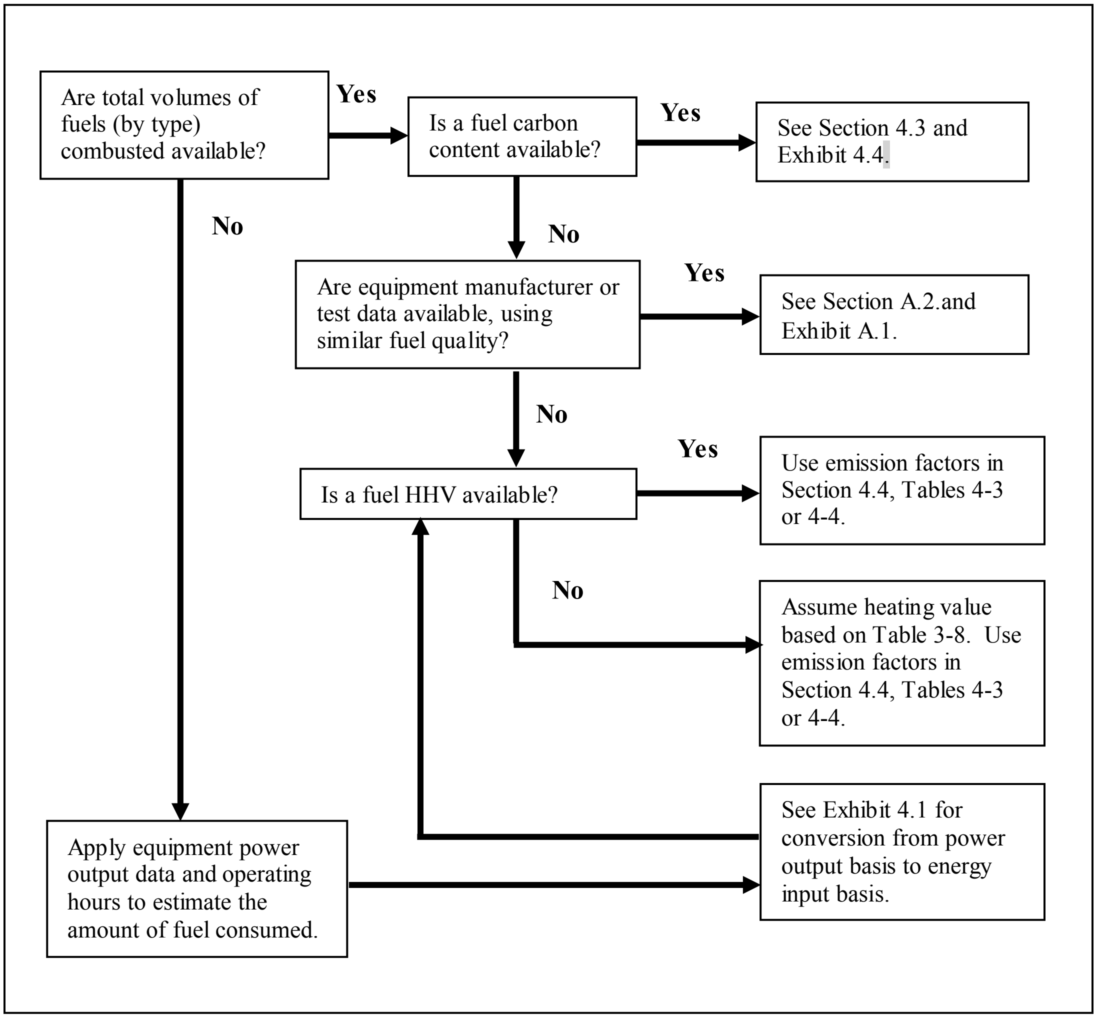

Figure 4-1. Calculating CO_2 Emissions from Stationary Combustion Sources (Not Including Waste Gas Disposal Sources)

Figure 4-1 provides several options based on the type of information available, such as volume of fuel combusted, fuel carbon content or HHV, equipment manufacturer or test data, and equipment power output data and operating hours. However, methodologies required by regulations take precedence over the options provided in the decision trees.

For CO_2 emissions from stationary combustion sources, the first approach relies on a measurement program to obtain the fuel consumption rate (in terms of mass or volume) and the fuel composition (i.e., carbon content). If such information is not available, manufacturer data, device-specific testing, or published emission factors are provided as other estimation methods. A methodology for calculating fuel consumption is provided in Section 4.1 where metered fuel use is not available. Where volumes of fuel combusted are not available, the volume can be estimated based on the energy output of the combustion equipment, which is dependent on the equipment rating, efficiency, and hours of operation.

The emission factors provided in this section are provided on a HHV basis. Emission factors published by IPCC that are provided in the sections below were originally on a LHV basis, but were converted to a HHV basis using the methodology described in Section 4.2.

Published emission factors for CO_2 provided in terms of tonnes per quantity of fuel consumed or tonnes per energy consumption of a given fuel are recognized as sufficient for estimating CO_2 emissions, as CO_2 emissions do not vary based on combustion technology (IPCC, 2006).

Methane emissions are estimated using published emission factors that incorporate a default fuel composition and CH_4 destruction efficiency based on the equipment type. These factors are discussed further in Section 4.4 for typical stationary combustion equipment and Section 4.5 for mobile sources. Where available, manufacturer supplied CH_4 emission factors may also be used.

Published emission factors are also used for estimating N_2O emissions from combustion sources. Where available, average N_2O emission factors based on reported test data are provided in Section 4.4 for typical stationary combustion equipment and Section 4.5 for mobile sources. Where available, manufacturer supplied N_2O emission factors may also be used.

Care must be taken to avoid double counting or underestimating emissions. In particular, fuel meters must be properly associated with the sources for which the emissions are being estimated, and fuel consumption should be accounted for all sources. For example, some refinery fuel gas sources may use supplemental natural gas as a fuel source. However, if emissions from the supplemental natural gas are already accounted for at a point further upstream, they should not be associated with the individual source because this would be double counting. In this case, measuring fuel consumption at a central header is desired unless equipment specific emission rates are needed. In addition, at a refinery, fuels are often metered at individual sources, but not all sources may be metered. In such a case, not all emissions would be accounted for using just the metered fuel rates.

4.1 Estimating Fuel Consumption Data from Energy Output or Volumetric Flow

This document has adopted an energy input basis for estimating combustion emissions. This approach is consistent with the actual fuel consumption volumes or mass rates, and accounts for the loss in efficiency. Using actual fuel consumption data is the API *Compendium* preferred method for estimating combustion emissions; this section describes methods for estimating fuel consumption, if actual consumption data are not available. Inclusion of all fuel streams is essential when using fuel volumes for determining GHG emissions.

4.1.1 Estimating Fuel Consumption from Equipment Data

For some locations, measured fuel data are not available. In this situation, equipment fuel consumption rates are estimated by converting energy output to energy input. Required data for this approach are:

1. Equipment rating (horsepower). Actual horsepower is more accurate, but manufacturer or maximum horsepower and load can be used to estimate fuel usage, recognizing that these ratings will overestimate emissions.

2. Operating hours. If monthly operating hours are available, total operating hours can be calculated using Equation 4-2.

$$\mathrm{OT} = \sum_{i=1}^{\#\,\mathrm{Months}} \left(\frac{\text{Total hours}}{\text{Month}} \right)_i \qquad \text{(Equation 4-2)}$$

where

OT = annual operating time (hr/year).

Alternatively, if runtime is tracked as a percent, Equation 4-3 can be used to calculate total operating hours.

$$\mathrm{OT} = \sum_{i=1}^{\#\,\mathrm{Months}} \left(\frac{\text{Default runtime}}{100} \times \frac{\text{Total hours}}{\text{Month}} \right)_i \qquad \text{(Equation 4-3)}$$

Finally, if downtime hours are tracked instead of runtime, total operating hours can be calculated using Equation 4-4.

$$\mathrm{OT} = \sum_{i=1}^{\#\,\text{Months}} \left(\frac{\text{Total Hours}}{\text{Month}} - \frac{\text{Downtime hours}}{\text{Month}} \right)_i \qquad \text{(Equation 4-4)}$$

3. Equipment thermal efficiency. This is provided in terms of heat input per energy output (Btu/hp-hr). Equipment vendors may specify a Btu/hp-hr conversion factor for a particular device to convert between power output and energy input. In the absence of this information, Table 4-2 provides power conversion factors for some common combustion sources. These factors can be used to convert from a rated power output to an estimated energy input.

4. Fuel properties. Regardless of fuel type (gas or liquid), the heating value and carbon content of the fuel will be needed. If the fuel being combusted is a liquid, the density of the fuel will also be needed. It is important to use the same heating value basis (i.e., HHV or LHV) for both thermal efficiency and fuel property.

Using this approach, fuel usage is calculated on an equipment basis by combining the data identified in Items 1 through 4 above, as shown in Equation 4-5:

$$\mathrm{FC} = \mathrm{ER} \times \mathrm{LF} \times \mathrm{OT} \times \mathrm{ETT} \times \frac{1}{\mathrm{HV}} \qquad \text{(Equation 4-5)}$$

where:

FC = annual fuel consumed (volume/yr);

ER = equipment rating (hp, kW, or J);

LF = equipment load factor (fraction);

OT = annual operating time (hr/yr);

ETT = equipment thermal efficiency ($\mathrm{Btu}_{\mathrm{input}}/\mathrm{hp\text{-}hr}_{\mathrm{output}}$, $\mathrm{Btu}_{\mathrm{input}}/\mathrm{kW\text{-}hr}_{\mathrm{output}}$, or $\mathrm{J}_{\mathrm{input}}/\mathrm{J}_{\mathrm{output}}$).; and

HV = fuel heating value (energy/volume).

Table 4-2. Energy Conversions by Generator Type

Generator Type	Fuel Type	Original Units	Converted Units				
			HHV Basis		LHV Basis [d]		
		Btu/kW-hr	Btu/hp-hr	J (input)/ J (output)	Btu/kW-hr	Btu/hp-hr	J (input)/ J (output)
Ultra-Supercritical coal (USC)[a]	Coal	8,638	6,441	2.532	8,206	6,119	2.405
USC with 30% carbon capture and sequestration (CCS) [a]	Coal	9,751	7,271	2.858	9,263	6,908	2.715
USC with 90% CCS [a]	Coal	12,507	9,327	3.666	11,882	8,860	3.482
Combined-cycle—single shaft [a]	Natural Gas	6,431	4,796	1.885	5,788	4,316	1.696
Combined-cycle—multi shaft [a]	Natural Gas	6,370	4,750	1.867	5,733	4,275	1.680
Combined-cycle with 90% CCS [a]	Natural Gas	7,124	5,312	2.088	6,412	4,781	1.879
Combustion turbine—aeroderivative [a]	Natural Gas	9,124	6,804	2.674	8,212	6,123	2.407
Combustion turbine—industrial frame [a]	Natural Gas	9,905	7,386	2.903	8,915	6,648	2.613
Fuel cells [a]	Natural Gas	6,469	4,824	1.896	5,822	4,342	1.706
Internal combustion engine	Natural Gas [a]	8,295	6,186	2.431	7,466	5,567	2.188
	No. 2 Fuel Oil [f]	10,847	8,089	3.179	10,305	7,684	3.020
	Gasoline [g]	9,387 (converted)	7,000 (original units)	2.751	8,918	6,650	2.614
	Refinery Gas [f]	14,000	10,440	4.103	12,600	9,396	3.693
Biomass [a]	Not specified	13,300	9,918	3.898	12,635	9,422	3.703
Combined Heat and Power (CHP) [b]	Not specified [e]	5,300 - 7,000	3,952-5,220	1.553-2.052	4,770-6,650	3,557-4,959	1.398-1.949
Steam Generator (Boiler)							
Coal [c]	Coal	10,002	7,459	2.931	9,502	7,086	2.785
Petroleum[c]	Petroleum	10,236	7,633	3.000	9,724	7,251	2.850
Natural Gas [c]	Natural Gas	10,347	7,716	3.032	9,312	6,944	2.729
No. 2 Fuel Oil [f]	No. 2 Fuel Oil	8,653	6,453	2.536	8,220	6,130	2.409

Footnotes and Sources:

[a] Energy Information Administration (EIA 2020), *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, Addendum, Table 1, February, 5, 2020. Fuel type is not specified; assume heat rate is the same for all fuel types.

[b] U.S. Environmental Protection Agency (EPA 2017), *Catalog of CHP Technologies*, Table 7-2. Packaged CHP Systems – Performance Characteristics, Total heat recovered, 30-99 kW.

[c] Energy Information Administration (EIA 2020a), Electric Power Annual, Table 8.2, Average Tested Heat Rates by Prime Mover and Energy Source, 2009 - 2019. Values are from 2019 data.

[d] For generator types where fuel type is not specified, HHV basis values should be multiplied by 0.90 (for gaseous fuels) or 0.95 (for solid or liquid fuels) to convert to LHV basis values, as appropriate for the fuel(s) being used.

[e] Assume natural gas

[f] Emission Inventory Improvement Program (EIIP), *Guidance for Emissions Inventory Development*, *Volume VIII: Estimating Greenhouse Gas Emissions*, EIIP Greenhouse Gas Committee, October 1999, Table 1.5-2.

[g] EPA, AP-42, Supplements A, B, and C, Table 3.3-1, October 1996.

Alternatively, some emission factors are reported on an energy input basis. The energy input is calculated using Equation 4-6.

$$E_{in} = ER \times LF \times OT \times ETT \tag{Equation 4-6}$$

where:

E_{in} = energy input (Btu, J);

ER = equipment rating (hp, kW, or J);

LF = equipment load factor (fraction);

OT = annual operating time (hr/yr); and

ETT = equipment thermal efficiency ($\text{Btu}_{\text{input}}/\text{hp-hr}_{\text{output}}$, $\text{Btu}_{\text{input}}/\text{kW-hr}_{\text{output}}$, or $\text{J}_{\text{input}}/\text{J}_{\text{output}}$).

Exhibit 4.1 demonstrates this conversion.

EXHIBIT 4.1: Sample Calculation for Converting from Energy Output to Energy Input Basis Prior to Estimating Emissions

INPUT DATA:
A 100-hp natural gas-fired IC engine is operated for 8,000 hours at 90% load during the reporting year. Calculate the energy input (E_{in}) in both U.S. customary and SI units, on an HHV basis.

CALCULATION METHODOLOGY:
1. *Calculate E_{In} in U.S. customary units.* The power output is converted to an energy input basis using a conversion factor of 6,186 Btu/hp-hr (HHV basis) from Table 4-2.

$$\mathbf{E_{in,US} = 100\ hp \times 0.90 \times \frac{8,000\ hr}{yr} \times \frac{6,186\ Btu}{hp - hr}}$$

$$\mathbf{E_{in,US} = 4.45 \times 10^{9}\ Btu/yr\ (HHV)}$$

2. *Calculate E_{In} in SI units.* The SI conversion factors presented in Table 4-2 are in units of J (input)/J (output). To convert the power output to energy input on an SI basis, the power output (P) must first be converted to energy output using a conversion factor from Table 3-4.

$$\text{P} = 100\ \text{hp} \times 0.90 \times \frac{8000\ \text{hr}}{\text{yr}} \times \frac{2.68452 \times 10^{6}\ \text{J}}{\text{hp-hr}}$$

$$\underline{\text{P} = 1.933 \times 10^{12}\ \text{J (output)/yr}}$$

Next, the energy output basis is converted to an input basis using a conversion factor of 2.431 J (input) / J (output) (HHV basis) from Table 4-2.

$$\mathbf{E_{in,SI} = \frac{1.933 \times 10^{12}\ J\ (output)}{yr} \times \frac{2.431\ J\ (input)}{J\ (output)}}$$

$$\mathbf{E_{in,SI} = 4.699 \times 10^{12}\ J\ (input)/yr\ (HHV)}$$

4.1.2 Conversion from Volumetric Flow Rate to Energy Input

If the fuel input is provided on a volumetric basis (scf/yr, for example), then fuel HHV factors given in Table 3-8 can be used to convert the fuel volumetric rate to a fuel-fired heat input rate (in Btu/year, for example). Exhibit 4.2 demonstrates this conversion.

EXHIBIT 4.2: Sample Calculation for Combustion Emissions Fuel Basis with Unknown Carbon Analysis

INPUT DATA:
800 million (10^6) scf/year of natural gas is burned in a combustion device. Neither the fuel composition nor the heating value of the fuel is known. Calculate the energy input (E_{In}) on an HHV basis.

CALCULATION METHODOLOGY:
The fuel volumetric rate is converted to heat input rate using a recommended HHV of 1020 Btu/scf for natural gas, provided in Table 3-8. Thus, the fuel heat input rate is:

$$E_{In} = \frac{800 \times 10^6 \text{ scf}}{\text{yr}} \times \frac{1020 \text{ Btu}}{\text{scf}}$$

$$\underline{E_{In} = 8.16 \times 10^{11} \text{ Btu/yr (HHV)}}$$

4.2 Conversion Between Gross and Net Heating Value

With the exception of the IPCC (IPCC, 2007), all of the combustion emission factor sources used in this section provide emission factors on a HHV basis. IPCC notes that their emission factors were originally based on gross calorific value, but converted the heating values to net calorific value by assuming the LHV is 5% lower than the HHV for coal and oil, and 10% lower for natural gas (IPCC, Volume 2, Chapter 2, Table 2.6, 2007). Any IPCC emission factors in the tables below were converted back to a HHV basis using these same percentages.

Applying IPCC's convention, emission factors that were originally reported on a LHV basis were converted to a HHV basis using Equations 4-7 (for gaseous fuels) and 4-8 (for solid/liquid fuels).[2]

For gaseous fuels,

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[2] Derivation of these equations (as noted in the footnotes to certain tables in this section) is provided in Appendix A.

$$EF_{HHV} = EF_{LHV} \times \left(\frac{1-0.1}{1} \right) \tag{Equation 4-7}$$

where

EF = Emission factor, mass or energy basis.

For solid or liquid fuels:

$$EF_{HHV} = EF_{LHV} \times \left(\frac{1-0.05}{1} \right) \tag{Equation 4-8}$$

Equations 4-7 and 4-8 were also used to convert any emission factors originally reported on a HHV basis to a LHV basis. For most stationary combustion sources, emission factors throughout Section 4 are presented on both a LHV basis and a HHV basis.

Exhibit 4.3 illustrates how to convert emission factors on an LHV basis to an HHV basis. The process for converting from an HHV basis to an LHV basis would be carried out in a similar manner.

EXHIBIT 4.3: Sample Calculation for Converting LHV to HHV

INPUT DATA:
IPCC reports the carbon factor of natural gas liquids as 17.5 kg C/GJ (17.5 tonne/10^{12} J) on an LHV basis (as shown in Table 4-3). Convert the carbon factor to a CO_2 emission factor (tonnes/Btu) on an HHV basis.

CALCULATION METHODOLOGY:
The first step in calculating the CO_2 emission factor is to convert the carbon factor to a HHV basis using Equation 4-8 and IPCC's assumption that the LHV for a liquid is 5% lower than the HHV. The conversion is shown below.

$$EF_{HHV} = \left(\frac{17.5 \text{ tonne C}}{10^{12} \text{ J}}\right)_{LHV} \times \left(\frac{1\text{-}0.05_{LHV}}{1_{HHV}}\right) = \left(\frac{16.63 \text{ tonne C}}{10^{12} \text{ J}}\right)_{HHV}$$

The carbon emission factor is then converted to a CO_2 emission factor using the compound molecular weights and the conversion factors presented in Table 3-4:

$$EF_{CO_2} = \frac{16.63 \text{ tonne C}}{10^{12}\text{J}} \times \frac{1055.056 \text{ J}}{\text{Btu}} \times \frac{44 \text{ tonne } CO_2\text{/tonne-mole } CO_2}{12 \text{ tonne C/tonne-mole C}}$$

$$\underline{EF_{CO_2} = 0.0643 \text{ tonnes } CO_2/10^6 \text{ Btu}}$$

4.3 Fuel Combustion Emissions Estimated from Fuel Composition and Usage

This section discusses estimating CO_2 emissions from fuel combustion. A material balance approach, based on fuel usage data and fuel carbon analyses, is the most reliable method for estimating emissions from stationary combustion sources. This approach applies to the combustion of any fuel, though fuel carbon analyses are likely more readily available for produced or purchased gas streams than for refinery gas, liquid or solid fuels.

The carbon content of a fuel mixture is a weighted average of the individual component carbon contents. This is determined by first calculating the weight percent (wt%) of carbon of each of the fuel components. This is accomplished by multiplying the molecular weight of carbon by the number of moles of carbon and dividing by the molecular weight of the compound. This is shown in Equation 4-9.

$$Wt\%C_{Cj} = \frac{\dfrac{12 \text{ lb C}}{\text{lbmole C}} \times \dfrac{\text{X lbmole C}}{\text{lbmole Cj}}}{MW_{Cj}\left(\dfrac{\text{lb}}{\text{lbmole}}\right)} \times 100\% \qquad \text{(Equation 4-9)}$$

where

Wt% C_{Cj} = carbon content of individual hydrocarbon compound on a mass percent basis;
j = any hydrocarbon compound $C_xH_yO_z$ from Equation 4-1;
12 = molecular weight of carbon;
X = Stoichiometric coefficient for carbon (for example X=3 for pentane, C_3H_8); and

MW_{C_XY} = molecular weight of individual hydrocarbon compound.

The carbon content of the fuel mixture can then be calculated using Equation 4-10.

$$Wt\%C_{Mixture} = \frac{1}{100} \times \sum_{i=1}^{\#\,components} \left(Wt\%_i \times Wt\%C_i\right) \qquad \text{(Equation 4-10)}$$

where

$Wt\%\ C_{Mixture}$ = carbon content of mixture, on mass percent basis;
$Wt\%_i$ = weight percent of component *i*; and
$Wt\%C_i$ = carbon content of component *i* on a weight percent basis, calculated using Equation 4-9.

The API *Compendium* has also adopted an assumption of complete combustion (i.e., 100% of the fuel carbon combusts to form CO_2) in estimating CO_2 emissions. In addition to estimating CO_2 emissions based on 100% oxidation of fuel carbon, the API *Compendium* estimates CH_4 emissions from combustion sources based on emission factors. This approach accounts for potential emissions of CH_4 (which has a higher GWP than CO_2), which may exist in the atmosphere before CH_4 is completely oxidized to form CO_2. Additional information on atmospheric oxidation of emissions is provided in Appendix D.

Emissions of CO_2 are calculated using a mass balance approach. The equations are slightly different depending on whether the fuel combusted is a gas, liquid, or solid. For combustion of gaseous fuels, CO_2 emissions can be calculated using Equation 4-11, assuming 100% oxidation:

$$E_{CO_2} = FC \times \frac{1}{\text{molar volume conversion}} \times MW_{Mixture} \times Wt\%\ C_{Mixture} \times \frac{44}{12} \qquad \text{(Equation 4-11)}$$

where

E_{CO_2} = mass emissions of CO_2 (lb or kg);
FC = fuel consumed (scf or m^3);
Molar volume conversion = conversion from molar volume to mass (379.3 scf/lbmole or 23.685 m^3/kgmole);
$MW_{Mixture}$ = molecular weight of mixture; and
$\frac{44}{12}$ = stoichiometric conversion of C to CO_2.

Carbon dioxide emissions from the combustion of liquid fuels can be calculated using Equation 4-12, assuming 100% oxidation:

$$E_{CO_2} = FC \times D \times Wt\%\ C_{Mixture} \times \frac{44}{12} \qquad \text{(Equation 4-12)}$$

where

FC = fuel consumed (gal or m^3); and
D = fuel density (lb/gal or kg/m^3).

Similarly, emissions from the combustion of solid fuels are calculated using Equation 4-13, assuming 100% oxidation.

$$E_{CO_2} = FC \times Wt\%\ C_{Mixture} \times \frac{44}{12} \qquad \text{(Equation 4-13)}$$

where

FC = fuel consumed in mass units (lb, kg, tonnes).

The following examples illustrate the calculation approach for stationary combustion CO_2 emissions based on fuel composition and consumption rate, independent of the type of equipment. Exhibit 4.4(a) first demonstrates the scenario where the fuel composition is known and used directly to derive the fuel carbon content. The calculation is also shown (Exhibit 4.4(b)) for a case where complete composition data are not available, but fuel carbon content and molecular weight are known (or default values are applied).

EXHIBIT 4.4(a): Sample Calculation for Fuel Basis (Gas Fuel) Combustion Emissions

INPUT DATA:
800 million (10^6) scf/year of natural gas is burned in a combustion device or group of devices. The gas composition for the fuel is known from measurements and is given below. The weight percents of the fuel components have been calculated from the molar composition. (See Exhibit 3.3 for a similar example of this conversion.)

	Mole %	MW	Wt% (Calculated)
CO_2	0.8	44	2.1
CH_4	95.3	16	90.6
C_2H_6	1.7	30	3.0
C_3H_8	0.5	44	1.3
C_4H_{10}	0.1	58	0.3
N_2	1.6	28	2.7
Fuel Mixture	**100**	**16.84**	**100.0**

Calculate the annual CO_2 emissions.

CALCULATION METHODOLOGY:
The first step in calculating the CO_2 emissions is calculating the carbon content of the fuel mixture, as shown in Equation 4-10. To use Equation 4-10, the carbon contents of the individual constituents must be calculated using Equation 4-9. This is shown below for ethane (C_2H_6).

$$\text{Wt\%C}_{C_2H_6} = \frac{12 \text{ lb C}}{\text{lbmole C}} \times \frac{2 \text{ lbmoles C}}{\text{lbmole } C_2H_6} \times \frac{\text{lbmole } C_2H_6}{30 \text{ lb } C_2H_6} = \underline{0.8 \text{ lb C/lb } C_2H_6}$$

$$\underline{\text{Wt\%C}_{C_2H_6} = 80\% \text{ C}}$$

EXHIBIT 4.4(b): Sample Calculation for Fuel Basis (Gas Fuel) Combustion Emissions

CALCULATION METHODOLOGY:
To calculate the CO_2 emissions, the fuel consumption is converted to a mass basis using the volumetric conversions presented in Section 3. The molecular weight and carbon content of the gas are then used to convert the mass of gas combusted to a mass of carbon combusted. The CO_2 emissions are calculated below:

$$E_{CO_2} = \frac{22 \times 10^6 \text{ m}^3 \text{ fuel}}{\text{yr}} \times \frac{10^6 \text{ cm}^3 \text{ fuel}}{\text{m}^3 \text{ fuel}} \times \frac{\text{gmole fuel}}{23{,}685 \text{ cm}^3 \text{ fuel}} \times \frac{17.4 \text{ g fuel}}{\text{gmole fuel}} \times \frac{76.2 \text{ g C}}{100 \text{ g fuel}} \times \frac{\text{gmole C}}{12 \text{ g C}}$$
$$\times \frac{\text{gmole } CO_2}{\text{gmole C}} \times \frac{44 \text{ g } CO_2}{\text{gmole } CO_2} \times \frac{\text{tonnes}}{10^6 \text{ g}}$$

$$\underline{E_{CO_2} = 45{,}157 \text{ tonnes } CO_2\text{/yr}}$$

For a liquid fuel, Exhibit 4.5 demonstrates the emission calculation approach for a case where the fuel carbon content, density, and heating value are known.

EXHIBIT 4.5: Sample Calculation for Fuel Basis (Liquid Fuel) Combustion Emissions

INPUT DATA:
4 million (10^6) gallons per year of No. 6 residual fuel is burned in a combustion device or group of devices. The density of the residual fuel is 8.3 lb/gallon; the wt% carbon of the fuel is 92.3%. Calculate the annual CO_2 emissions for a site where detailed fuel information is known (or default values are applied).

CALCULATION METHODOLOGY:
The CO_2 emissions are calculated based on the density and carbon content, as shown below.

$$E_{CO_2} = \frac{4\times10^6 \text{ gal fuel}}{\text{year}} \times \frac{8.3 \text{ lb fuel}}{\text{gal fuel}} \times \frac{92.3 \text{ lb C}}{100 \text{ lb fuel}} \times \frac{\text{lbmole C}}{12 \text{ lb C}} \times \frac{1 \text{ lbmole } CO_2}{1 \text{ lbmole C}} \times \frac{44 \text{ lb } CO_2}{\text{lbmole } CO_2} \times \frac{\text{tonnes}}{2204.62 \text{ lb}}$$

$$\underline{E_{CO_2} = 50{,}966 \text{ tonnes } CO_2/\text{yr}}$$

4.4 Fuel Combustion Emissions Estimated on a Fuel Basis for Stationary Sources

As illustrated in the decision tree (Figure 4-1), if fuel carbon analyses are not available, emissions from fuel combustion may be estimated using default average fuel compositions. In addition, although this *API Compendium* has adopted an assumption of complete combustion in estimating CO_2 emissions, other protocols may apply a fractional conversion of carbon to estimate CO_2 emissions from combustion sources.[3] This section addresses the use of average fuel compositions and carbon oxidation values as an optional approach.

4.4.1 Emission Estimation Using Default Average Fuel Composition

If only the facility fuel consumption rate is known, and a fuel carbon analysis is not available, emission factors based on default average fuel compositions can be used to estimate combustion emissions. Table 4-3 lists CO_2 emission factors for common fuel types used in petroleum operations, while Table 4-4 lists CO_2 emission factors for more specialized and less common fuels.

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[3] The carbon oxidation factor is intended to reflect carbon that is emitted as soot or ash.

As mentioned previously, the *API Compendium* provides guidance for selecting appropriate estimation techniques based on the intended use of the inventory data and the availability of required input data. Operators reporting under regulations with specific methodologies should use those methods. In the U.S., many oil and gas facilities must report GHG emissions under the U.S. EPA Mandatory Greenhouse Gas Reporting program, codified in at 40 CFR Part 98. Table 4-5 presents Part 98 CO_2 fuel combustion emission factors.

Similar factors are provided in Tables 4-6 and 4-7 for CH_4 and N_2O for common and specialized fuels, respectively. Table 4-8 presents emission factors for CH_4 and N_2O from the U.S. EPA Mandatory Greenhouse Gas Reporting program. These emission factors are appropriate for both external combustion (e.g., boilers and heaters) as well as internal combustion (e.g., engines and turbines).

Note that the use of fuel based CH_4 and N_2O emission factors does not take into account other factors which influence CH_4 and N_2O emissions, such as combustion and control technologies. The methodology for calculating CH_4 and N_2O emissions by equipment type is provided in Section 4.5.

Table 4-3. CO_2 Combustion Emission Factors (Fuel Basis) for Common Industry Fuel Types

	Carbon Emission Factor from Original Source Document			**CO_2 Emission Factor [a, b], US Units**		**CO_2 Emission Factor [a,b], SI Units**	
Fuel	**Emission Factor**		**Source[c]**	**tonnes/10^6 Btu (LHV)**	**tonnes /10^6 Btu (HHV)**	**tonnes /10^{12} J (LHV)**	**tonnes /10^{12} J (HHV)**
Aviation Gas	18.86	MMTC/10^{15} Btu	Table A-32, EPA, 2021.	0.0727	0.0691	69.0	65.5
Biodiesel (100%)	20.14	kg C/10^6 Btu	Table 1.1, TCR, 2021.	0.0777	0.0738	73.6	69.9
Biogas (captured methane)	14.2	kg C/10^6 Btu	Table 1.1, TCR, 2021.	0.0579	0.0521	54.9	49.4
Bitumen	22.0	kg C/10^9 J (LHV)	Table 1.3, IPCC, 2007.	0.0851	0.0809	80.7	76.6
Coke	31.0	kg C/10^6 Btu	Table B-1, EPA, 2008; Table 1.1, TCR, 2021.	0.1199	0.1139	113.7	108.0
Coke (Coke Oven/Lignite/Gas)	29.2	kg C/109 J (LHV)	Table 1.3, IPCC, 2007.	0.113	0.1073	107.1	101.7
Crude Oil	20.31	MMTC/10^{15} Btu	Table A-32, EPA, 2021.	0.0783	0.0744	74.3	70.5
Distillate Fuel #1	19.98	MMTC/10^{15} Btu	Table A-38, EPA, 2021; Table 1.1, TCR, 2021.	0.0771	0.0732	73.0	69.4
Distillate Fuel #2	20.22	MMTC/10^{15} Btu	Table A-38, EPA, 2021.	0.0780	0.0741	73.9	70.2
Distillate Fuel #4	20.47	MMTC/10^{15} Btu	Table A-38, EPA, 2021; Table 1.1, TCR, 2021.	0.0790	0.0750	74.8	71.1
Electric Utility Coal	No Data [c]		Table 6-1, EIA, 2008.	0.0997	0.0947	94.5	89.8
	26.076	MMTC/10^{15} Btu	Table A-32, EPA, 2021.	0.1006	0.09554	95.3	90.6
Ethanol [d]	19.3	kg C/10^9 J (LHV)	Table 1.3, IPCC, 2007.	0.0747	0.0709	70.8	67.2
	18.67	kg C/10^6 Btu	Table 1.1, TCR, 2021.	0.0720	0.0684	68.2	64.8
Ethylene	17.99	MMTC/10^{15} Btu	Table A-40, EPA, 2021.	0.0732	0.0659	69.4	62.5
Flexicoker Low Btu Gas	278	lb CO_2/10^6 Btu (LHV)	Petroleum Industry Data.	0.1261	0.1135	119.5	107.6
Gas/Diesel Oil [e]	20.2	kg C/10^9 J (LHV)	Table 1.3, IPCC, 2007.	0.0781	0.0742	74.1	70.4
Isobutylene	18.78	MMTC/10^{15} Btu	Table A-40, EPA, 2021.	0.0724	0.0688	68.7	65.2

	Carbon Emission Factor from Original Source Document			CO_2 Emission Factor [a, b], US Units		CO_2 Emission Factor [a,b], SI Units	
Fuel	**Emission Factor**		**Source[c]**	**tonnes/10^6 Btu (LHV)**	**tonnes /10^6 Btu (HHV)**	**tonnes /10^{12} J (LHV)**	**tonnes /10^{12} J (HHV)**
Jet Fuel	19.7	MMTC/10^{15} Btu	Table A-32, EPA, 2021.	0.0760	0.0722	72.0	68.4
Kerosene	19.96	MMTC/10^{15} Btu	Table A-32, EPA, 2021.	0.0770	0.0731	73.0	69.3
Lignite	26.698	MMTC/10^{15} Btu	Table A-33, EPA, 2021.	0.1030	0.0978	97.6	92.7
Liquefied Petroleum Gas (LPG)	17.15	MMTC/10^{15} Btu	Table A-32, EPA, 2021.	0.0662	0.0628	62.7	59.6
(LPG Other source)	17.23	kg C/MMBtu	Table B-1, EPA, 2008; Table 12.1, TCR, 2008.	0.0665	0.0632	63	59.9
Butane (normal)	17.66	MMTC/10^{15} Btu	Table A-32, EPA, 2021.	0.0681	0.0647	64.6	61.3
Butane (other source)	17.72	Tg C/10^{15} Btu; kg C/MMBtu.	Table A-42, EPA, 2009; Table 12.1, TCR, 2008.	0.0684	0.065	64.8	61.6
Butylene	18.74	MMTC/10^{15} Btu	Table A-32, EPA, 2021.	0.0723	0.0687	68.5	65.1
Ethane	16.25	MMTC/10^{15} Btu	Table A-40, EPA, 2021.	0.0627	0.0595	59.4	56.4
Isobutane	17.71	MMTC/10^{15} Btu	Table A-40, EPA, 2021.	0.0683	0.0649	64.7	61.5
Propane	17.15	MMTC/10^{15} Btu	Table A-40, EPA, 2021.	0.0662	0.0628	62.7	59.6
Propylene	17.99	MMTC/10^{15} Btu	Table A-40, EPA, 2021.	0.0694	0.0659	65.8	62.5
Miscellaneous Product [e,f]	No Data [c]		Table 6-1, EIA, 2008.	0.0785	0.0745	74.4	70.7
Motor Gasoline (Petrol)	19.46	MMTC/10^{15} Btu	Table A-32, EPA, 2021.	0.0751	0.0713	71.1	67.6
Naphtha (<401°F)	18.55	MMTC/10^{15} Btu	Table A-32, EPA, 2021.	0.0716	0.0680	67.8	64.4
Nat. Gas Liquids	17.5	kg C/10^9 J (LHV)	Table 1.3, IPCC, 2007.	0.0677	0.0643	64.2	61
Natural Gas (Pipeline) [g]	14.43	MMTC/10^{15} Btu	Table A-32, EPA, 2021.	0.0588	0.0529	55.7	50.1
Other Bituminous Coal	25.8	kg C/10^9 J (LHV)	Table 1.3, IPCC, 2007.	0.0998	0.0948	94.6	89.9
Other Oil (>401°F)	20.17	MMTC/10^{15} Btu	Table A-32, EPA, 2021.	0.0778	0.0739	73.7	70.1
Pentanes Plus	18.24	MMTC/10^{15} Btu	Table A-32, EPA, 2021.	0.0704	0.0668	66.7	63.3

	Carbon Emission Factor from Original Source Document			**CO_2 Emission Factor [a, b], US Units**		**CO_2 Emission Factor [a,b], SI Units**	
Fuel	**Emission Factor**		**Source[c]**	**tonnes/10^6 Btu (LHV)**	**tonnes /10^6 Btu (HHV)**	**tonnes /10^{12} J (LHV)**	**tonnes /10^{12} J (HHV)**
Petroleum Coke [h]	27.85	MMTC/10^{15} Btu	Table A-32, EPA, 2021.	0.1074	0.1020	101.8	96.7
Refinery Gas	15.7	kg C/10^9 J (LHV)	Table 1.3, IPCC, 2007.	0.0607	0.0547	57.6	51.8
Residual Oil #5	19.89	MMTC/10^{15} Btu	Table A-38, EPA, 2021; Table 1.1, TCR, 2021.	0.0767	0.0729	72.7	69.1
Residual Oil #6[i]	20.48	MMTC/10^{15} Btu	Table A-32, EPA, 2021; Table 1.1, TCR, 2021.	0.0790	0.0750	74.9	71.1
Special Naphtha	19.74	MMTC/10^{15} Btu	Table A-32, EPA, 2021.	0.0761	0.0723	72.2	68.6
Still Gas	18.2	MMTC/10^{15} Btu	Table A-32, EPA, 2021; Table 1.1, TCR, 2021.	0.0741	0.0667	70.2	63.2
Sub-bituminous Coal	26.444	MMTC/10^{15} Btu	Table A-33, EPA, 2021.	0.1020	0.0969	96.7	91.8
Unfinished Oils [e,f]	20.31	MMTC/10^{15} Btu	Table A-32, EPA, 2021.	0.0783	0.0744	74.3	70.5

Footnotes and Sources:

Energy Information Administration (EIA). Documentation for Emissions of Greenhouse Gases in the United States 2006, DOE/EIA-0638(2006), October 2008.

Environmental Protection Agency (EPA). Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007, Annexes, April 15, 2009.

Environmental Protection Agency (EPA). Climate Leaders. Greenhouse Gas Inventory Protocol Core Module Guidance: Direct Emissions from Stationary Combustion Sources. EPA 430-K-08-003, May 2008 (2008).

Environmental Protection Agency (EPA). Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2019, Annexes U.S. Environmental Protection Agency, Washington D.C., May 2021 (2021). Original values are average of U.S. data for 2015-2019 (2019 latest available).

Intergovernmental Panel on Climate Change (IPCC). 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2, Chapter 1, 2006 Revised April 2007. (Note: 2019 revision of the IPCC Guidelines did not revise the combustion emission factors.)

The Climate Registry (TCR). 2021 Default Emission Factor Document. https://www.theclimateregistry.org/wp-content/uploads/2021/05/2021-Default-Emission-Factor-Document.pdf?mc_cid=4b45d12237&mc_eid=5f138d1baa.

[a] CO_2 emission factors shown are based on the default API Compendium assumption of 100% oxidation.

[b] To convert between higher and lower heating value emission factors, the assumed conversion for gaseous fuels is: (EF, HHV) = (0.9) × (EF, LHV), and for solids or liquids the assumed conversion is (EF, HHV) = (0.95) × (EF, LHV).

[c] Factors from EIA, 2008 Tables 6-1 and 6-2 are presented in 10^6 tonne/10^{15} Btu.

[d] Theoretical number. Under international GHG accounting methods developed by the IPCC, biogenic carbon is considered to be part of the natural carbon balance and does not add to atmospheric concentrations of CO_2.

[e] Term is defined in the Glossary.

[f] Carbon content assumed to be the same as for Crude Oil (EIA, 2007).

[g] Natual gas carbon coefficient is based on a weighted U.S. national average. Note that this is also the same natural gas emission factor in The Climate Registry *2021 Default Emission Factor Document* for natural gas with HHV between 1,000 to 1.025 Btu.

[h] Note that catalyst coke is not the same as petroleum coke/marketable coke. Catalyst coke refers to coke formed on catalysts while petroleum/marketable coke is coke that is the "final product of thermal decomposition in the condensation process in cracking" (EIA, 2008b). Carbon dioxide emissions from catalyst coke are discussed in Section 6.

[i] Values are defined in reference documents as for both residual fuel oil No. 5 and residual fuel oil No. 6.

Table 4-4. CO_2 Combustion Emission Factors (Fuel Basis) for Specialized Fuel Types

	Carbon Emission Factor from Original Source Document			**CO_2 Emission Factor [a, b], US Units**		**CO_2 Emission Factor [a,b], SI Units**	
Fuel		**Emission Factor**	**Source[c]**	**tonnes/10^6 Btu (LHV)**	**tonnes /10^6 Btu (HHV)**	**tonnes /10^{12} J (LHV)**	**tonnes /10^{12} J (HHV)**
Anthracite Coal	28.28	MMTC/QBtu;	Table A-33, EPA, 2021;	0.1091	0.1036	103.4	98.21
Asphalt and Road Oil	20.55	MMTC/QBtu;	Table A-32, EPA, 2021;	0.0793	0.0753	75.1	71.4
Bituminous Coal	25.432	MMTC/QBtu;	Table A-33, EPA, 2021;	0.0981	0.0932	93.0	88.3
Industrial Coking Coal	25.576	MMTC/QBtu;	Table A-32, EPA, 2021;	0.0986	0.0937	93.5	88.8
Lubricants	20.2	MMTC/QBtu;	Table A-32, EPA, 2021;	0.0779	0.0740	73.8	70.2
Oil Shale and Tar Sands	29.1	kg C/GJ (LHV)	Table 1.3, IPCC, 2007.	0.1126	0.1066	106.7	101.4
Other Industrial Coal		No Data [c]	Table 6-1, EIA, 2008.	0.0989	0.0940	93.8	89.1
	25.63	Tg C/10^{15} Btu	Table A-35, EPA, 2009; Table 12.1, TCR, 2008.	0.0989	0.0940	93.8	89.1
Peat	30.5	kg C/10^6 Btu	Table 1.1, TCR, 2021.	0.1244	0.1182	117.9	112.0
Petroleum Feedstocks	19.37	MMTC/10^{15} Btu; Tg C/10^{15} Btu.	Table 6-1, EIA, 2008; Table A-34, EPA, 2009; Table 1.1, TCR, 2021.	0.0748	0.0710	70.9	67.3
Residential/ Commercial Coal		No Data [c]	Table 6-1, EIA, 2008.	0.1004	0.0953	95.1	90.4
	26.056	MMTC/QBtu;	Table A-32, EPA, 2021;	0.1005	0.0955	95.3	90.5
Shale Oil	20.0	kg C/GJ (LHV)	Table 1.3, IPCC, 2007.	0.0774	0.0735	73.3	69.7
Petroleum Waxes	19.8	MMTC/QBtu;	Table A-32, EPA, 2021	0.0764	0.0725	72.4	68.8

	Carbon Emission Factor from Original Source Document			**CO_2 Emission Factor [a, b], US Units**		**CO_2 Emission Factor [a,b], SI Units**	
Fuel	**Emission Factor**		**Source[c]**	**tonnes/10^6 Btu (LHV)**	**tonnes /10^6 Btu (HHV)**	**tonnes /10^{12} J (LHV)**	**tonnes /10^{12} J (HHV)**
Tires/Tire Derived Fuel	86.0	kg CO_2/MMBtu	Appendix H, EIA, 2007b.	0.0905	0.0860	85.8	81.5
Waste Oil [c]	9.98	kg CO_2/gal	Appendix H, EIA, 2007b.	No data			
Wastewater Treatment Biogas [d]	14.2	kg C/10^6 Btu	Table 1.1, TCR, 2021.	0.0579	0.0521	54.9	49.4

Footnotes and Sources:

Energy Information Administration (EIA). Documentation for Emissions of Greenhouse Gases in the United States 2006 , DOE/EIA-0638(2006), October 2008.

Energy Information Administration (EIA). Instructions for Form EIA-1605, OMDB No. 1905-0194, October 2007 (2007b).

Environmental Protection Agency (EPA). Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2019, Annexs. U.S. Environmental Protection Agency, Washington D.C., May 2021 (2021). Original values are average of U.S. data for 2015-2019 (2019 latest available).

Intergovernmental Panel on Climate Change (IPCC). 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2, Chapter 1, 2006 Revised April 2007.

The Climate Registry (TCR). 2021 Default Emission Factor Document. https://www.theclimateregistry.org/wp-content/uploads/2021/05/2021-Default-Emission-Factor-Document.pdf?mc_cid=4b45d12237&mc_eid=5f138d1baa.

[a] CO_2 emission factors shown are based on the default API Compendium assumption of 100% oxidation.

[b] To convert between higher and lower heating value emission factors, the assumed conversion for gaseous fuels is: (EF, HHV) = (0.9) × (EF, LHV), and for solids or liquids the assumed conversion is (EF, HHV) = (0.95) × (EF, LHV).

[c] Factors from EIA, 2008 Tables 6-1 and 6-2 are presented in 10^6 tonne/10^{15} Btu.

[d] Derived from the EPA Climate Leaders Technical Guidance (2008) Table B-2, as referenced in the The Climate Registry *2021 Default Emission Factor Document*.

Table 4-5. CO_2 Combustion Emission Factors from EPA Mandatory GHG Reporting Rule [a]

Fuel	Default HHVs	CO_2 Emission Factor Original Units	CO_2 Emission Factor Converted	
	Original Units in MMBtu	kg CO_2/MMBtu (HHV)	tonne CO_2/MMBtu (HHV)	tonne CO_2/MMBtu (LHV) [b]
Anthracite	25.09 MMBtu/short ton	103.69	0.1037	0.1091
Bituminous Coal	24.93 MMBtu/short ton	93.28	0.0933	0.0982
Subbituminous	17.25 MMBtu/short ton	97.17	0.0972	0.1023
Lignite	14.21 MMBtu/short ton	97.72	0.0977	0.1029
Coal Coke	24.80 MMBtu/short ton	113.67	0.1137	0.1197
Mixed (Commercial Sector)	21.39 MMBtu/short ton	94.27	0.0943	0.0992
Mixed (Industrial coking)	26.28 MMBtu/short ton	93.90	0.0939	0.0988
Mixed (industrial sector)	22.35 MMBtu/short ton	94.67	0.0947	0.0997
Mixed (Electric Power Sector)	19.73 MMBtu/short ton	95.52	0.0955	0.1005
Petroleum Coke	30.00 MMBtu/short ton	102.41	0.1024	0.1078
Municipal Solid Waste	9.95 MMBtu/short ton	90.70	0.0907	0.0955
Tires	28.00 MMBtu/short ton	85.97	0.0860	0.0905
Plastics	38.00 MMBtu/short ton	75.00	0.0750	0.0789
Wood and Wood Residuals (dry basis)	17.48 MMBtu/short ton	93.80	0.0938	0.0987
Agricultural Byproducts	8.25 MMBtu/short ton	118.17	0.1182	0.1244
Peat	8.00 MMBtu/short ton	111.84	0.1118	0.1177
Solid Byproducts	10.39 MMBtu/short ton	105.51	0.1055	0.1111
Natural Gas	1.026E-03 MMBtu/scf	53.06	0.0531	0.0590
Propane Gas	2.516E-03 MMBtu/scf	61.46	0.0615	0.0683
Blast Furnace Gas	9.20E-05 MMBtu/scf	274.32	0.2743	0.3048
Coke Oven Gas	5.99E-04 MMBtu/scf	46.85	0.0469	0.0521
Fuel Gas	1.39E-03 MMBtu/scf	59.00	0.0590	0.0656
Landfill Gas	4.85E-04 MMBtu/scf	52.07	0.0521	0.0579

Fuel	Default HHVs	CO_2 Emission Factor Original Units	CO_2 Emission Factor Converted	
	Original Units in MMBtu	kg CO_2/MMBtu (HHV)	tonne CO_2/MMBtu (HHV)	tonne CO_2/MMBtu (LHV) [b]
Other Biomass Gas	6.55E-04 MMBtu/scf	52.07	0.0521	0.0579
Distillate Fuel Oil No. 1	0.139 MMBtu/gallon	73.25	0.0733	0.0771
Distillate Fuel Oil No. 2	0.138 MMBtu/gallon	73.96	0.0740	0.0779
Distillate Fuel Oil No. 4	0.146 MMBtu/gallon	75.04	0.0750	0.0790
Distillate Fuel Oil No. 5	0.140 MMBtu/gallon	72.93	0.0729	0.0768
Distillate Fuel Oil No. 6	0.150 MMBtu/gallon	75.10	0.0751	0.0791
Used Oil	0.138 MMBtu/gallon	74.00	0.0740	0.0779
Kerosene	0.135 MMBtu/gallon	75.20	0.0752	0.0792
Liquified Petroleum Gas (LPG)	0.092 MMBtu/gallon	61.71	0.0617	0.0650
Propane	0.091 MMBtu/gallon	62.87	0.0629	0.0662
Propylene	0.091 MMBtu/gallon	67.77	0.0678	0.0713
Ethane	0.068 MMBtu/gallon	59.60	0.0596	0.0627
Ethanol	0.084 MMBtu/gallon	68.44	0.0684	0.0720
Ethylene	0.058 MMBtu/gallon	65.96	0.0660	0.0694
Isobutane	0.099 MMBtu/gallon	64.94	0.0649	0.0684
Isobutylene	0.103 MMBtu/gallon	68.86	0.0689	0.0725
Butane	0.103 MMBtu/gallon	64.77	0.0648	0.0682
Butylene	0.105 MMBtu/gallon	68.72	0.0687	0.0723
Naphtha (<401 deg F)	0.125 MMBtu/gallon	68.02	0.0680	0.0716
Natural Gasoline	0.110 MMBtu/gallon	66.88	0.0669	0.0704
Other Oil (>401 deg F)	0.139 MMBtu/gallon	76.22	0.0762	0.0802
Pentanes Plus	0.110 MMBtu/gallon	70.02	0.0700	0.0737
Petrochemical Feedstocks	0.125 MMBtu/gallon	71.02	0.0710	0.0748
Special Naphtha	0.125 MMBtu/gallon	72.34	0.0723	0.0761
Unfinished Oils	0.139 MMBtu/gallon	74.54	0.0745	0.0785
Heavy Gas Oils	0.148 MMBtu/gallon	74.92	0.0749	0.0789
Lubricants	0.144 MMBtu/gallon	74.27	0.0743	0.0782
Motor Gasoline	0.125 MMBtu/gallon	70.22	0.0702	0.0739

Fuel	Default HHVs	CO_2 Emission Factor Original Units	CO_2 Emission Factor Converted	
	Original Units in MMBtu	kg CO_2/MMBtu (HHV)	tonne CO_2/MMBtu (HHV)	tonne CO_2/MMBtu (LHV) [b]
Aviation Gasoline	0.120 MMBtu/gallon	69.25	0.0693	0.0729
Kerosene - Type Jet Fuel	0.135 MMBtu/gallon	72.22	0.0722	0.0760
Asphalt and Road Oil	0.158 MMBtu/gallon	75.36	0.0754	0.0793
Crude Oil	0.138 MMBtu/gallon	74.54	0.0745	0.0785
Ethanol	0.084 MMBtu/gallon	68.44	0.0684	0.0720
Biodiesel (100%)	0.128 MMBtu/gallon	73.84	0.0738	0.0777
Rendered Animal Fat	0.125 MMBtu/gallon	71.06	0.0711	0.0748
Vegetable Oil	0.120 MMBtu/gallon	81.55	0.0816	0.0858

Footnotes and Sources:

[a] Code of Federal Regulations (CFR), 40 C.F.R. § 98.33, Mandatory Greenhouse Gas Reporting Subpart C: General Stationary Fuel Combustion Sources, December 2016 (2016).

[b] To convert between higher and lower heating value emission factors, the assumed conversion for gaseous fuels is: (EF, HHV) = (EF, LHV)/(0.9), and for solids or liquids the assumed conversion is (EF, HHV) = (EF, LHV)/(0.95).

Table 4-6. CH_4 and N_2O Combustion Emission Factors (Fuel Basis) for Common Industry Fuel Types [a]

	CH_4 Emission Factor [b], US Units		CH_4 Emission Factor [b], SI Units		N_2O Emission Factor [b], US Units		N_2O Emission Factor [b], SI Units	
Fuel	**tonnes/10^6 Btu (LHV)**	**tonnes /10^6 Btu (HHV)**	**tonnes/10^{12} J (LHV)**	**tonnes/10^{12} J (HHV)**	**tonnes/10^6 Btu (LHV)**	**tonnes /10^6 Btu (HHV)**	**tonnes /10^{12} J (LHV)**	**tonnes /10^{12} J (HHV)**
Aviation Gasoline/Jet Gasoline	3.16E-06	3.00E-06	2.99E-03	2.84E-03	6.32E-07	6.00E-07	5.99E-04	5.69E-04
Biodiesels	1.16E-06	1.10E-06	1.10E-03	1.04E-03	1.16E-07	1.10E-07	1.10E-04	1.04E-04
Biogasoline[c]	3.16E-06	3.00E-06	2.99E-03	2.84E-03	6.32E-07	6.00E-07	5.99E-04	5.69E-04
Bitumen[c]	3.16E-06	3.00E-06	2.99E-03	2.84E-03	6.32E-07	6.00E-07	5.99E-04	5.69E-04
Coke Oven and Lignite Coke	1.16E-05	1.10E-05	1.10E-02	1.04E-02	1.68E-06	1.60E-06	1.60E-03	1.52E-03
Crude Oil	3.16E-06	3.00E-06	2.99E-03	2.84E-03	6.32E-07	6.00E-07	5.99E-04	5.69E-04
Ethane	3.16E-06	3.00E-06	2.99E-03	2.84E-03	6.32E-07	6.00E-07	5.99E-04	5.69E-04
Heavy Gas Oils	3.16E-06	3.00E-06	2.99E-03	2.84E-03	6.32E-07	6.00E-07	5.99E-04	5.69E-04
Jet Gasoline	3.16E-06	3.00E-06	2.99E-03	2.84E-03	6.32E-07	6.00E-07	5.99E-04	5.69E-04
Kerosene	3.16E-06	3.00E-06	2.99E-03	2.84E-03	6.32E-07	6.00E-07	5.99E-04	5.69E-04
Lignite	1.16E-05	1.10E-05	1.10E-02	1.04E-02	1.68E-06	1.60E-06	1.60E-03	1.52E-03
LPG	3.16E-06	3.00E-06	2.99E-03	2.84E-03	6.32E-07	6.00E-07	5.99E-04	5.69E-04
Motor Gasoline	3.16E-06	3.00E-06	2.99E-03	2.84E-03	6.32E-07	6.00E-07	5.99E-04	5.69E-04
Naphtha	3.16E-06	3.00E-06	2.99E-03	2.84E-03	6.32E-07	6.00E-07	5.99E-04	5.69E-04
Natural Gas	1.11E-06	1.00E-06	1.05E-03	9.48E-04	1.11E-07	1.00E-07	1.05E-04	9.48E-05
Natural Gasoline	3.16E-06	3.00E-06	2.99E-03	2.84E-03	6.32E-07	6.00E-07	5.99E-04	5.69E-04
Other Biogas	3.56E-06	3.20E-06	3.37E-03	3.03E-03	7.00E-07	6.30E-07	6.63E-04	5.97E-04
Other Kerosene[c]	3.16E-06	3.00E-06	2.99E-03	2.84E-03	6.32E-07	6.00E-07	5.99E-04	5.69E-04
Other Liquid Biofuels	1.16E-06	1.10E-06	1.10E-03	1.04E-03	1.16E-07	1.10E-07	1.10E-04	1.04E-04

	CH_4 Emission Factor [b], US Units		**CH_4 Emission Factor [b], SI Units**		**N_2O Emission Factor [b], US Units**		**N_2O Emission Factor [b], SI Units**	
Fuel	**tonnes/10^6 Btu (LHV)**	**tonnes /10^6 Btu (HHV)**	**tonnes/10^{12} J (LHV)**	**tonnes/10^{12} J (HHV)**	**tonnes/10^6 Btu (LHV)**	**tonnes /10^6 Btu (HHV)**	**tonnes /10^{12} J (LHV)**	**tonnes /10^{12} J (HHV)**
Other Oil (>401 deg F)	3.16E-06	3.00E-06	2.99E-03	2.84E-03	6.32E-07	6.00E-07	5.99E-04	5.69E-04
Other Primary Solid Biomass	2.00E-06	1.90E-06	1.90E-03	1.80E-03	4.42E-07	4.20E-07	4.19E-04	3.98E-04
Paraffin Waxes[c]	3.16E-06	3.00E-06	2.99E-03	2.84E-03	6.32E-07	6.00E-07	5.99E-04	5.69E-04
Petroleum Coke	3.37E-05	3.20E-05	3.19E-02	3.03E-02	4.42E-06	4.20E-06	4.19E-03	3.98E-03
Residual Fuel Oil	3.16E-06	3.00E-06	2.99E-03	2.84E-03	6.32E-07	6.00E-07	5.99E-04	5.69E-04
Sub-Bituminous Coal	1.16E-05	1.10E-05	1.10E-02	1.04E-02	1.68E-06	1.60E-06	1.60E-03	1.52E-03
Wood/Wood Waste	7.58E-06	7.20E-06	7.18E-03	6.82E-03	3.79E-06	3.60E-06	3.59E-03	3.41E-03

Footnotes and Sources:

[a] US EPA Emission Factors for Greenhouse Gas Inventories, Last Modified 1 April 2021

[b] Converted from original units of kg/TJ (LHV). To convert between higher and lower heating value emission factors, the assumed conversion for gaseous fuels is: (EF, HHV) = (0.9) × (EF, LHV), and for solids or liquids the assumed conversion is (EF, HHV) = (0.95) × (EF, LHV).

[c] Intergovernmental Panel on Climate Change (IPCC). *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, Volume 2, Chapter 2, Table 2.2, 2006 Revised April 2007.

Table 4-7. CH_4 and N_2O Combustion Emission Factors (Fuel Basis) for Specialized Fuel Types [a]

	CH_4 Emission Factor [b], US Units		CH_4 Emission Factor [b], SI Units		N_2O Emission Factor [b], US Units		N_2O Emission Factor [b], SI Units	
Fuel	**tonnes/10^6 Btu (LHV)**	**tonnes /10^6 Btu (HHV)**	**tonnes/10^{12} J (LHV)**	**tonnes/10^{12} J (HHV)**	**tonnes/10^6 Btu (LHV)**	**tonnes /10^6 Btu (HHV)**	**tonnes /10^{12} J (LHV)**	**tonnes /10^{12} J (HHV)**
Anthracite	1.16E-05	1.10E-05	1.10E-02	1.04E-02	1.68E-06	1.60E-06	1.60E-03	1.52E-03
Bituminous Coal	1.16E-05	1.10E-05	1.10E-02	1.04E-02	1.68E-06	1.60E-06	1.60E-03	1.52E-03
Charcoal	1.16E-05	1.10E-05	1.10E-02	1.04E-02	1.68E-06	1.60E-06	1.60E-03	1.52E-03
Coal Tar[c]	1.16E-05	1.10E-05	1.10E-02	1.04E-02	1.68E-06	1.60E-06	1.60E-03	1.52E-03
Coke Oven Gas	5.33E-07	4.80E-07	5.06E-04	4.55E-04	1.11E-07	1.00E-07	1.05E-04	9.48E-05
Coking Coal[c]	1.16E-05	1.10E-05	1.10E-02	1.04E-02	1.68E-06	1.60E-06	1.60E-03	1.52E-03
Landfill Gas	3.56E-06	3.20E-06	3.37E-03	3.03E-03	7.00E-07	6.30E-07	6.63E-04	5.97E-04
Lubricants	3.16E-06	3.00E-06	2.99E-03	2.84E-03	6.32E-07	6.00E-07	5.99E-04	5.69E-04
Oil Shale and Tar Sands[c]	1.16E-05	1.10E-05	1.10E-02	1.04E-02	1.68E-06	1.60E-06	1.60E-03	1.52E-03
Peat	3.37E-05	3.20E-05	3.19E-02	3.03E-02	4.42E-06	4.20E-06	4.19E-03	3.98E-03
Petroleum Feedstocks	3.16E-06	3.00E-06	2.99E-03	2.84E-03	6.32E-07	6.00E-07	5.99E-04	5.69E-04
Refinery Gas (Fuel Gas)	3.33E-06	3.00E-06	3.16E-03	2.84E-03	6.67E-07	6.00E-07	6.32E-04	5.69E-04
Shale Oil[c]	1.16E-05	1.10E-05	1.10E-02	1.04E-02	1.68E-06	1.60E-06	1.60E-03	1.52E-03
Sludge Gas[c]	1.22E-05	1.10E-05	1.16E-02	1.04E-02	1.78E-06	1.60E-06	1.69E-03	1.52E-03

Footnotes and Sources:

[a] US EPA Emission Factors for Greenhouse Gas Inventories, Last Modified 1 April 2021 (EPA 2021a).

[b] Converted from original units of kg/TJ (LHV). To convert between higher and lower heating value emission factors, the assumed conversion for gaseous fuels is: (EF, HHV) = (0.9) × (EF, LHV), and for solids or liquids the assumed conversion is (EF, HHV) = (0.95) × (EF, LHV).

[c] Intergovernmental Panel on Climate Change (IPCC). *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, Volume 2, Chapter 2, Table 2.2, 2006 Revised April 2007.

Table 4-8. CH_4 and N_2O Combustion Emission Factors from EPA Mandatory GHG Reporting Rule [a]

Fuel	CH_4 Emission Factor Original Units	CH_4 Emission Factor Converted		N_2O Emission Factor Original Units	N_2O Emission Factor Converted	
	kg CH_4/MMBtu (HHV)	tonne CH_4/MMBtu (HHV)	tonne CH_4/MMBtu (LHV)	kg N_2O/MMBtu (HHV)	tonne N_2O/MMBtu (HHV)	tonne N_2O/MMBtu (LHV)
Anthracite	1.10E-02	1.10E-05	1.16E-05	1.60E-03	1.60E-06	1.68E-06
Bituminous Coal	1.10E-02	1.10E-05	1.16E-05	1.60E-03	1.60E-06	1.68E-06
Subbituminous	1.10E-02	1.10E-05	1.16E-05	1.60E-03	1.60E-06	1.68E-06
Lignite	1.10E-02	1.10E-05	1.16E-05	1.60E-03	1.60E-06	1.68E-06
Coal Coke	1.10E-02	1.10E-05	1.16E-05	1.60E-03	1.60E-06	1.68E-06
Mixed (Commercial Sector)	1.10E-02	1.10E-05	1.16E-05	1.60E-03	1.60E-06	1.68E-06
Mixed (Industrial coking)	1.10E-02	1.10E-05	1.16E-05	1.60E-03	1.60E-06	1.68E-06
Mixed (industrial sector)	1.10E-02	1.10E-05	1.16E-05	1.60E-03	1.60E-06	1.68E-06
Mixed (Electric Power Sector)	1.10E-02	1.10E-05	1.16E-05	1.60E-03	1.60E-06	1.68E-06
Petroleum Coke	3.00E-03	3.00E-06	3.16E-06	6.00E-04	6.00E-07	6.32E-07
Municipal Solid Waste	3.20E-02	3.20E-05	3.37E-05	4.20E-03	4.20E-06	4.42E-06
Tires	3.20E-02	3.20E-05	3.37E-05	4.20E-03	4.20E-06	4.42E-06
Plastics	3.20E-02	3.20E-05	3.37E-05	4.20E-03	4.20E-06	4.42E-06
Wood and Wood Residuals (dry basis)	7.20E-03	7.20E-06	7.58E-06	3.60E-03	3.60E-06	3.79E-06
Agricultural Byproducts	3.20E-02	3.20E-05	3.37E-05	4.20E-03	4.20E-06	4.42E-06
Peat	3.20E-02	3.20E-05	3.37E-05	4.20E-03	4.20E-06	4.42E-06
Solid Byproducts	3.20E-02	3.20E-05	3.37E-05	4.20E-03	4.20E-06	4.42E-06
Natural Gas	1.00E-03	1.00E-06	1.11E-06	1.00E-04	1.00E-07	1.11E-07

Fuel	**CH_4 Emission Factor Original Units**	**CH_4 Emission Factor Converted**		**N_2O Emission Factor Original Units**	**N_2O Emission Factor Converted**	
	kg CH_4/MMBtu (HHV)	**tonne CH_4/MMBtu (HHV)**	**tonne CH_4/MMBtu (LHV)**	**kg N_2O/MMBtu (HHV)**	**tonne N_2O/MMBtu (HHV)**	**tonne N_2O/MMBtu (LHV)**
Propane Gas	3.00E-03	3.00E-06	3.33E-06	6.00E-04	6.00E-07	6.67E-07
Blast Furnace Gas	2.20E-05	2.20E-08	2.44E-08	1.00E-04	1.00E-07	1.11E-07
Coke Oven Gas	4.80E-04	4.80E-07	5.33E-07	1.00E-04	1.00E-07	1.11E-07
Fuel Gas	3.00E-03	3.00E-06	3.33E-06	6.00E-04	6.00E-07	6.67E-07
Landfill Gas	--	--	--	--	--	--
Other Biomass Gas	--	--	--	--	--	--
Distillate Fuel Oil No. 1	3.00E-03	3.00E-06	3.16E-06	6.00E-04	6.00E-07	6.32E-07
Distillate Fuel Oil No. 2	3.00E-03	3.00E-06	3.16E-06	6.00E-04	6.00E-07	6.32E-07
Distillate Fuel Oil No. 4	3.00E-03	3.00E-06	3.16E-06	6.00E-04	6.00E-07	6.32E-07
Distillate Fuel Oil No. 5	3.00E-03	3.00E-06	3.16E-06	6.00E-04	6.00E-07	6.32E-07
Distillate Fuel Oil No. 6	3.00E-03	3.00E-06	3.16E-06	6.00E-04	6.00E-07	6.32E-07
Used Oil	3.00E-03	3.00E-06	3.16E-06	6.00E-04	6.00E-07	6.32E-07
Kerosene	3.00E-03	3.00E-06	3.16E-06	6.00E-04	6.00E-07	6.32E-07
Liquified Petroleum Gas (LPG)	3.00E-03	3.00E-06	3.16E-06	6.00E-04	6.00E-07	6.32E-07
Propane	3.00E-03	3.00E-06	3.16E-06	6.00E-04	6.00E-07	6.32E-07
Propylene	3.00E-03	3.00E-06	3.16E-06	6.00E-04	6.00E-07	6.32E-07
Ethane	3.00E-03	3.00E-06	3.16E-06	6.00E-04	6.00E-07	6.32E-07
Ethanol	3.00E-03	3.00E-06	3.16E-06	6.00E-04	6.00E-07	6.32E-07
Ethylene	3.00E-03	3.00E-06	3.16E-06	6.00E-04	6.00E-07	6.32E-07
Isobutane	3.00E-03	3.00E-06	3.16E-06	6.00E-04	6.00E-07	6.32E-07
Isobutylene	3.00E-03	3.00E-06	3.16E-06	6.00E-04	6.00E-07	6.32E-07
Butane	3.00E-03	3.00E-06	3.16E-06	6.00E-04	6.00E-07	6.32E-07
Butylene	3.00E-03	3.00E-06	3.16E-06	6.00E-04	6.00E-07	6.32E-07

Fuel	CH_4 Emission Factor Original Units	CH_4 Emission Factor Converted		N_2O Emission Factor Original Units	N_2O Emission Factor Converted	
	kg CH_4/MMBtu (HHV)	tonne CH_4/MMBtu (HHV)	tonne CH_4/MMBtu (LHV)	kg N_2O/MMBtu (HHV)	tonne N_2O/MMBtu (HHV)	tonne N_2O/MMBtu (LHV)
Naphtha (<401 deg F)	3.00E-03	3.00E-06	3.16E-06	6.00E-04	6.00E-07	6.32E-07
Natural Gasoline	3.00E-03	3.00E-06	3.16E-06	6.00E-04	6.00E-07	6.32E-07
Other Oil (>401 deg F)	3.00E-03	3.00E-06	3.16E-06	6.00E-04	6.00E-07	6.32E-07
Pentanes Plus	3.00E-03	3.00E-06	3.16E-06	6.00E-04	6.00E-07	6.32E-07
Petrochemical Feedstocks	3.00E-03	3.00E-06	3.16E-06	6.00E-04	6.00E-07	6.32E-07
Special Naphtha	3.00E-03	3.00E-06	3.16E-06	6.00E-04	6.00E-07	6.32E-07
Unfinished Oils	3.00E-03	3.00E-06	3.16E-06	6.00E-04	6.00E-07	6.32E-07
Heavy Gas Oils	3.00E-03	3.00E-06	3.16E-06	6.00E-04	6.00E-07	6.32E-07
Lubricants	3.00E-03	3.00E-06	3.16E-06	6.00E-04	6.00E-07	6.32E-07
Motor Gasoline	3.00E-03	3.00E-06	3.16E-06	6.00E-04	6.00E-07	6.32E-07
Aviation Gasoline	3.00E-03	3.00E-06	3.16E-06	6.00E-04	6.00E-07	6.32E-07
Kerosene - Type Jet Fuel	3.00E-03	3.00E-06	3.16E-06	6.00E-04	6.00E-07	6.32E-07
Asphalt and Road Oil	3.00E-03	3.00E-06	3.16E-06	6.00E-04	6.00E-07	6.32E-07
Crude Oil	3.00E-03	3.00E-06	3.16E-06	6.00E-04	6.00E-07	6.32E-07
Ethanol	1.10E-03	1.10E-06	1.16E-06	1.10E-04	1.10E-07	1.16E-07
Biodiesel (100%)	1.10E-03	1.10E-06	1.16E-06	1.10E-04	1.10E-07	1.16E-07
Rendered Animal Fat	1.10E-03	1.10E-06	1.16E-06	1.10E-04	1.10E-07	1.16E-07
Vegetable Oil	1.10E-03	1.10E-06	1.16E-06	1.10E-04	1.10E-07	1.16E-07

Footnotes and Sources:

[a] Code of Federal Regulations (CFR), 40 C.F.R. § 98.33, Mandatory Greenhouse Gas Reporting Subpart C: General Stationary Fuel Combustion Sources, December 2016 (2016).

[b] Converted from original units of kg/TJ (LHV). To convert between higher and lower heating value emission factors, the assumed conversion for gaseous fuels is: (EF, HHV) = (0.9) × (EF, LHV), and for solids or liquids the assumed conversion is (EF, HHV) = (0.95) × (EF, LHV).

4.4.2 Carbon Oxidation Values

The CO_2 emission factors shown in Tables 4-3 and 4-4 are converted from a carbon basis (mass of carbon emitted per fuel energy input) to a CO_2 basis, assuming all of the fuel carbon is oxidized to form CO_2 (i.e., 100% oxidation). As noted earlier, the carbon oxidation value reflects unoxidizable carbon that is emitted as a solid in soot or ash. In the past, some protocols have assumed that only a fraction of carbon emitted is oxidized; however, the 100% oxidation assumption is a common approach, adopted by the IPCC (2006), EIA (2011) and EPA (2008). EIA notes that "unless the carbon is consciously sequestered, it is likely to oxidize over the next 100 years" (EIA, 2007).

Exhibit 4.6 illustrates the use of the fuel-based emission factors for the 100% oxidation approach. Note the difference between the emission estimate calculated in Exhibit 4.5, where the fuel composition data are known, and Exhibit 4.6, where CO_2 emissions are calculated based on an emission factor that incorporates a default fuel composition.

EXHIBIT 4.6: Sample Calculation for Fuel Basis (Liquid Fuel) Combustion Emissions – Known (or assumed): Higher Heating Value (HHV) only

INPUT DATA:
4 million (10^6) gallons per year of No. 6 residual fuel is burned in a combustion device or group of devices. Calculate the annual CO_2 emissions, CH_4, and N_2O emissions.

CALCULATION METHODOLOGY:
1. *Calculate the CO_2 emissions.* If only the fuel type is known, an emission factor can be obtained from Table 4-3. Although the carbon emission factors presented in Table 4-3 have already been converted to CO_2 emission factors, the CO_2 emission factor for residual fuel oil #6 is re-calculated from the carbon emission factor as a demonstration in this exhibit. From Table 4-3, the carbon emission factor for residual fuel oil #6 is 20.48 MMTC/10^{15} Btu (10^6 tonne C/10^{15} Btu) (HHV). This factor is converted to a CO_2 basis as shown below:

$$\mathrm{EF_{CO_2}} = \frac{20.48\ \mathrm{MMTC}}{\mathrm{QBtu}} \times \frac{10^6\ \mathrm{tonne\ C}}{\mathrm{MMTC}} \times \frac{2204.62\ \mathrm{lb\ C}}{\mathrm{tonne\ C}} \times \frac{\mathrm{QBtu}}{10^{15}\ \mathrm{Btu}} \times \frac{10^6\ \mathrm{Btu}}{\mathrm{MMBtu}} \times \frac{\mathrm{lbmole\ C}}{12\ \mathrm{lb\ C}} \times \frac{1\ \mathrm{lbmole\ CO_2}}{1\ \mathrm{lbmole\ C}} \times \frac{44\ \mathrm{lb\ CO_2}}{\mathrm{lbmole\ CO_2}} \times \frac{\mathrm{tonne\ CO_2}}{2204.62\ \mathrm{lb\ CO_2}}$$

$\mathrm{EF_{CO_2}} = 0.0751$ tonnes $CO_2/10^6$ Btu (HHV)

Because the emission factor is on an energy basis, the fuel consumption must be converted to energy consumption using the heating value or energy content for the fuel type. (Default heating values are provided in Table 3-8 for some fuels.) The annual CO_2 emissions are calculated using the fuel usage data, default emission factor, and default heating value from Table 3-8.

$$E_{CO_2} = \frac{0.0751 \text{ tonnes } CO_2}{10^6 \text{ Btu}} \times \frac{4 \times 10^6 \text{ gal fuel}}{\text{year}} \times \frac{\text{bbl fuel}}{42 \text{ gal fuel}} \times \frac{6.29 \times 10^6 \text{ Btu}}{\text{bbl fuel}}$$

$$E_{CO_2} = 44{,}984 \text{ tonnes } CO_2\text{/yr}$$

2. *Calculate the CH_4 and N_2O emissions.* Methane and N_2O emissions are calculated using the emission factors for residual fuel oil in Table 4-5.

$$E_{CH_4} = \frac{3.01\times10^{-6} \text{ tonne } CH_4}{10^6 \text{ Btu}} \times \frac{4\times10^6 \text{ gal fuel}}{\text{year}} \times \frac{\text{bbl fuel}}{42 \text{ gal fuel}} \times \frac{6.29\times10^6 \text{ Btu}}{\text{bbl fuel}}$$

$$\underline{E_{CH_4} = 1.80 \text{ tonne } CH_4\text{/yr}}$$

$$E_{N_2O} = \frac{6.01\times10^{-7} \text{ tonne } N_2O}{10^6 \text{ Btu}} \times \frac{4\times10^6 \text{ gal fuel}}{\text{year}} \times \frac{\text{bbl fuel}}{42 \text{ gal fuel}} \times \frac{6.29\times10^6 \text{ Btu}}{\text{bbl fuel}}$$

$$\underline{E_{N_2O} = 0.36 \text{ tonne } N_2O\text{/yr}}$$

4.5 Fuel Combustion Emissions Estimated on an Equipment Basis for Stationary Sources

If the fuel usage is known for the specific type of equipment (e.g., boiler, turbine, IC engine, etc.) or groups of the same equipment, then equipment-specific emission factors can be used to estimate non-CO_2 emissions (CH_4 and N_2O).

Other GHG reporting protocol documents may provide CO_2 emission factors for stationary combustion on an equipment basis. However, these emission factors are inconsistent with the API *Compendium's* approach of estimating CO_2 emissions based on 100% oxidation of the fuel carbon, and the recognition that CO_2 emissions are independent of the type of combustion equipment.

Most of the equipment-specific emission factors are taken from EPA's AP-42 (EPA, AP-42, 1995-Present). These emission factors are updated periodically with the latest factors available at the following Internet address: https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors[4].

4.5.1 External Combustion Units

Tables 4-9 and 4-10 provide CH_4 and N_2O emission factors for external combustion devices. Emission factors in Tables 4-9 and 4-10 are primarily from EPA's AP-42 (EPA, AP-42, 1995-Present). The few exceptions are additional emission factors for refinery fuel gas-fired heaters from Asociacion Regional De Empresas De Petroleo Y Gas Natural EN LatinoAmerica Y El Caribe (ARPEL) (ARPEL, 1998) and for diesel-fired boilers/furnaces from the E&P Forum (E&P Forum, 1994). Also, the wood fuel/wood waste emission factor is from Environment Canada (Environment Canada, 2020). Table 4-9 applies to liquid and gaseous fuels while Table 4-10 applies to solid fuels such as coal.

With the exception of fuel gas-fired boilers/furnaces/heaters, the emission factors from external combustion are provided on a volume (scf or gallons) of fuel basis for gaseous or liquid fuels, and mass (tonnes) of fuel basis for solid fuels. If the firing rate is given on a volume or mass basis, the heating values for various fuels provided in Table 3-8 of this document can be used to convert the fuel firing rate (energy input basis) to an energy basis.

An example calculation for CH_4 and N_2O emissions from an external combustion device is shown in Exhibit 4.7.

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[4] Accessed June 30, 2021.

EXHIBIT 4.7: Sample Calculation for Combustion Emissions Equipment Basis for External Combustion Device

INPUT DATA:
800 million (10^6) scf/year of natural gas is burned in a boiler with a low-NO_x burner. The heating value of the gas is 1032 Btu/scf (HHV). Calculate the CH_4 and N_2O emissions.

CALCULATION METHODOLOGY:
Methane and N_2O emissions are calculated by converting the quantity of fuel burned to a Btu basis and multiplying the result by the emission factors provided in Table 4-7.

$$E_{CH_4} = \frac{800 \times 10^6 \text{ scf}}{\text{yr}} \times \frac{1032 \text{ Btu}}{\text{scf}} \times \frac{1.0 \times 10^{-6} \text{ tonne CH}_4}{10^6 \text{ Btu}} = \underline{0.83 \text{ tonnes CH}_4\text{/yr}}$$

$$E_{N_2O} = \frac{800 \times 10^6 \text{ scf}}{\text{yr}} \times \frac{1032 \text{ Btu}}{\text{scf}} \times \frac{2.8 \times 10^{-7} \text{ tonne N}_2\text{O}}{10^6 \text{ Btu}} = \underline{0.23 \text{ tonnes N}_2\text{O/yr}}$$

Table 4-9. Equipment-Specific Combustion Emission Factors for Boilers and Furnaces (Gas and Liquid Fuels)

Original Units

Source	**Methane**		**Emission Factor Rating[d]**	**Nitrous Oxide**		**Emission Factor Rating[d]**	**Source (version date)**
Boilers/furnaces/heaters – Natural gas							
Controlled	2.3	lb/10^6 scf	B	0.64[a]	lb/10^6 scf[a]	E	AP-42 Table 1.4-2 (7/98)
Not controlled				2.2[b]	lb/10^6 scf[b]		
Boilers/furnaces/heaters – Diesel	7.8E-06	lb/lb	Not available	Not available			E&P Forum, 1994
Heater – Refinery fuel gas (low H_2-content gas)							
< 9.9 x 10^6 Btu/hr	0.263	tonne/PJ (HHV)	Not available	Not available			Table 6.4 of ARPEL, 1998
9.9 – 99 x 10^6 Btu/hr	0.293	tonne/PJ (HHV)	Not available	0.035	tonne/PJ (HHV)	Not available	
>99 x 10^6 Btu/hr	0.293	tonne/PJ (HHV)	Not available	Not available			
Heater – Refinery fuel gas (High H_2-content gas)							
< 9.9 x 10^6 Btu/hr	0.193	tonne/PJ (HHV)	Not available	Not available			Table 6.4 of ARPEL, 1998
9.9 – 99x10^6 Btu/hr	0.215	tonne/PJ (HHV)	Not available	0.035	tonne/PJ (HHV)	Not available	
> 99 x 10^6 Btu/hr	0.215	tonne/PJ (HHV)	Not available	Not available			
Utility boilers – No. 4,5,6 oil	0.28	lb/1000 gal	A	0.53	lb/1000 gal	B	AP-42 Tables 1.3-3 and 1.3-8 (9/98) - errata updated 4/28/00
Industrial boiler – No. 5/6 oil	1.00	lb/1000 gal	A	0.53	lb/1000 gal	B	AP-42 Tables 1.3-3 and 1.3-8 (9/98) - errata updated 4/28/00
Industrial boiler – No. 4 or distillate oil	0.052	lb/1000 gal	A	0.26	lb/1000 gal	B	AP-42 Tables 1.3-3 and 1.3-8 (9/98) - errata updated 4/28/00
Commercial combustors – No. 5/6 oil	0.475	lb/1000 gal	A	0.53	lb/1000 gal	B	AP-42 Tables 1.3-3 and 1.3-8 (9/98) - errata updated 4/28/00
Commercial combustors – No. 4 or distillate	0.216	lb/1000 gal	A	0.26	lb/1000 gal	B	AP-42 Tables 1.3-3 and 1.3-8 (9/98) - errata updated 4/28/00
Industrial/commercial boilers – Butane/Propane	0.2	lb/1000 gal	E	0.9	lb/1000 gal	E	AP-42 Table 1.5-1 (07/08)
Residential furnace – Fuel oil	1.78	lb/1000 gal	A	0.05	lb/1000 gal	B	AP-42 Tables 1.3-3 and 1.3-8 (9/98)

Table 4-9. Equipment-Specific Combustion Emission Factors for Boilers and Furnaces (Gas and Liquid Fuels), continued

Emission Factors Converted to tonne/gal or tonne/106 Btu (HHV and LHV, as indicated)					
Source	**Methane**	**Emission Factor Rating [d]**	**Nitrous Oxide**	**Emission Factor Rating [d]**	**Source (version date)**
Boilers/furnaces/heaters – Natural gas					
Controlled	1.0E-06 tonne/10^6 Btu (HHV)[c] 1.1E-06 tonne/10^6 Btu (LHV)[c]	B	2.8E-07 tonne/10^6 Btu (HHV) [a,c] 3.0E-07 tonne/10^6 Btu (LHV) [a,c]	E E	AP-42 Table 1.4-2 (7/98)
Not controlled	1.0E-06 tonne/10^6 Btu (HHV)[c] 1.1E-06 tonne/10^6 Btu (LHV)[c]	B	9.8E-07 tonne/10^6 Btu (HHV) [b,c] 1.0E-06 tonne/10^6 Btu (LHV) [b,c]	E E	AP-42 Table 1.4-2 (7/98)
Boilers/furnaces/heaters – Diesel	7.8E-06 tonne/ tonne	Not available	Not available		E&P Forum, 1994
Heater – Refinery fuel gas (low H_2-content gas)					
< 9.9 x 10^6 Btu/hr	2.77E-07 tonne/10^6 Btu (HHV) 3.08E-07 tonne/10^6 Btu (LHV)	Not available	Not available		Table 6.4 of ARPEL, 1998
9.9 – 99 x 10^6 Btu/hr	3.09E-07 tonne/10^6 Btu (HHV) 3.43E-07 tonne/10^6 Btu (LHV)	Not available	3.69E-08 tonne/10^6 Btu (HHV) 4.10E-08 tonne/10^6 Btu (LHV)	Not available	
> 99 x 10^6 Btu/hr	3.09E-07 tonne/10^6 Btu (HHV) 3.43E-07 tonne/10^6 Btu (LHV)	Not available	Not available		
Heater – Refinery fuel gas (High H_2-content gas)					
< 9.9 x 10^6 Btu/hr	2.04E-07 tonne/10^6 Btu (HHV) 2.26E-07 tonne/10^6 Btu (LHV)	Not available	Not available		Table 6.4 of ARPEL, 1998
9.9 – 99 x 10^6 Btu/hr	2.27E-07 tonne/10^6 Btu (HHV) 2.52E-07 tonne/10^6 Btu (LHV)	Not available	3.69E-08 tonne/10^6 Btu (HHV) 4.10E-08 tonne/10^6 Btu (LHV)	Not available	
> 99 x 10^6 Btu/hr	2.27E-07 tonne/10^6 Btu (HHV) 2.52E-07 tonne/10^6 Btu (LHV)	Not available	Not available		
Utility boilers – No. 4,5,6 oil	1.3E-07 tonne/gal	A	2.4E-07 tonne/gal	B	AP-42 Tables 1.3-3 and 1.3-8 (9/98) - errata updated 4/28/00
Industrial boiler – No. 5/6 oil	4.54E-07 tonne/gal	A	2.4E-07 tonne/gal	B	AP-42 Tables 1.3-3 and 1.3-8 (9/98) - errata updated 4/28/00
Industrial boiler – No. 4 or distillate oil	2.4E-08 tonne/gal	A	1.2E-07 tonne/gal	B	AP-42 Tables 1.3-3 and 1.3-8 (9/98) - errata updated 4/28/00

Table 4-9. Equipment-Specific Combustion Emission Factors for Boilers and Furnaces (Gas and Liquid Fuels), continued

Emission Factors Converted to tonne/gal or tonne/10^6 Btu (HHV and LHV, as indicated), continued

Source	Methane	Emission Factor Rating [d]	Nitrous Oxide	Emission Factor Rating [d]	Source (version date)
Commercial combustors – No. 5/6 oil	2.15E-07 tonne/gal	A	2.4E-07 tonne/gal	B	AP-42 Tables 1.3-3 and 1.3-8 (9/98) - errata updated 4/28/00
Commercial combustors – No. 4 or distillate	9.80E-08 tonne/gal	A	1.2E-07 tonne/gal	B	AP-42 Tables 1.3-3 and 1.3-8 (9/98) - errata updated 4/28/00
Industrial/commercial boilers – Butane/Propane	9.1E-08 tonne/gal	E	4.1E-07 tonne/gal	E	AP-42 Table 1.5-1 (07/08)
Residential furnace – Fuel oil	8.07E-07 tonne/gal	A	2.3E-08 tonne/gal	B	AP-42 Tables 1.3-3 and 1.3-8 (9/98)

Emission Factors Converted to tonne/m3 or tonne/1012 J (HHV and LHV, as indicated)

Source	Methane	Emission Factor Rating [d]	Nitrous Oxide	Emission Factor Rating [d]	Source (version date)
Boilers/furnaces/heaters – Natural gas					
Controlled	9.7E-04 tonne/10^{12} J (HHV)[c] 1.1E-03 tonne/10^{12} J (LHV)[c]	B	2.7E-04 tonne/10^{12} J (HHV) [a,c] 2.8E-04 tonne/10^{12} J (LHV) [a,c]	E E	AP-42 Table 1.4-2 (7/98)
Not controlled	9.7E-04 tonne/10^{12} J (HHV)[c] 1.1E-03 tonne/10^{12} J (LHV)[c]	B	9.3E-04 tonne/10^{12} J (HHV) [b,c] 9.8E-04 tonne/10^{12} J (LHV) [b,c]	E E	AP-42 Table 1.4-2 (7/98)
Boilers/furnaces/heaters – Diesel	7.8E-06 tonne/ tonne	Not available	Not available		E&P Forum, 1994
Heater – Refinery fuel gas (low H_2-content gas)					
< 9.9 x 10^6 Btu/hr	2.63E-04 tonne/10^{12} J (HHV) 2.92E-04 tonne/10^{12} J (LHV)	Not available	Not available		Table 6.4 of ARPEL, 1998
9.9 – 99 x 10^6 Btu/hr	2.93E-04 tonne/10^{12} J (HHV) 3.26E-04 tonne/10^{12} J (LHV)	Not available	3.50E-05 tonne/10^{12} J (HHV) 3.89E-05 tonne/10^{12} J (LHV)	Not available	
> 99 x 10^6 Btu/hr	2.93E-04 tonne/10^{12} J (HHV) 3.26E-04 tonne/10^{12} J (LHV)	Not available	Not available		

Table 4-9. Equipment-Specific Combustion Emission Factors for Boilers and Furnaces (Gas and Liquid Fuels), continued

Emission Factors Converted to tonne/m^3 or tonne/10^{12} J (HHV and LHV, as indicated)

Source	Methane	Emission Factor Rating [d]	Nitrous Oxide	Emission Factor Rating [d]	Source (version date)
Heater – Refinery fuel gas (High H_2-content gas)					
< 9.9 x 10^6 Btu/hr	1.93E-04 tonne/10^{12} J (HHV) 2.14E-04 tonne/10^{12} J (LHV)	Not available	Not available		Table 6.4 of ARPEL, 1998
9.9 - 99 x 10^6 Btu/hr	2.15E-04 tonne/10^{12} J (HHV) 2.39E-04 tonne/10^{12} J (LHV)	Not available	3.50E-05 tonne/10^{12} J (HHV) 3.89E-05 tonne/10^{12} J (LHV)	Not available	
> 99 x 10^6 Btu/hr	2.15E-04 tonne/10^{12} J (HHV) 2.39E-04 tonne/10^{12} J (LHV)	Not available	Not available		
Utility boilers – No. 4,5,6 oil	3.4E-05 tonne/m^3	A	6.4E-05 tonne/m^3	B	AP-42 Tables 1.3-3 and 1.3-8 (9/98) - errata updated 4/28/00
Industrial boiler – No. 5/6 oil	1.20E-04 tonne/m^3	A	6.4E-05 tonne/m^3	B	
Industrial boiler – No. 4 or distillate oil	6.2E-06 tonne/m^3	A	3.1E-05 tonne/m^3	B	
Commercial combustors – No. 5/6 oil	5.69E-05 tonne/m^3	A	6.4E-05 tonne/m^3	B	
Commercial combustors – No. 4 or distillate	2.59E-05 tonne/m^3	A	3.1E-05 tonne/m^3	B	
Industrial/commercial boilers – Butane/Propane	2.4E-05 tonne/m^3	E	1.1E-04 tonne/m^3	E	AP-42 Table 1.5-1 (07/08)
Residential furnace – Fuel oil	2.13E-04 tonne/m^3	A	6.0E-06 tonne/m^3	B	AP-42 Tables 1.3-3 and 1.3-12 (9/98)

Footnotes and Sources:

Asociacion Regional De Empresas De Petroleo Y Gas Natural EN LatinoAmerica Y El Caribe (ARPEL). *Atmospheric Emissions Inventories Methodologies in the Petroleum Industry.* ARPEL Guideline # ARPELCIDA02AEGUI2298, Prepared by Jaques Whitford Environment Limited, December 1998.

E&P Forum. *Methods for Estimating Atmospheric Emissions from E&P Operations*, The Oil Industry International Exploration and Production Forum, Report No. 2.59/197, September 1994.

U.S. Environmental Protection Agency (EPA). *Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources,* AP-42, (GPO 055-000-005-001), US EPA Office of Air Quality Planning and Standards, Fifth Edition, January 1995, with Supplements A, B, and C, 1996; Supplement D, 1998 – errata updated 4/28/00; Supplement E, 1999; and Supplement F, 2000.

[a] Emission factor is for a natural gas, controlled low-NOx burner unit.

[b] Emission factor is for uncontrolled natural gas units.

[c] The Btu-based emission factors for natural gas boiler/furnaces/heaters are derived from the volume-based (scf) factor by dividing by 1020 Btu/scf (the default heating value used by AP-42). This factor may be used for other natural gas combustion sources. Gas volumes are based on standard conditions of 60°F and 14.7 psia.

[d] Emission factor rating pertains to the quality of the data; "A" has the best quality while "E" has the poorest quality.

Table 4-10. Equipment-Specific Combustion Emission Factors for Boilers and Furnaces (Solid Fuels) [a]

Original Units					
Source	**Methane**	**Emission Factor Rating [b]**	**Nitrous Oxide**	**Emission Factor Rating [b]**	**Source (version date)**
Boilers - Bituminous and Sub-bituminous Coal					
PC-fired, dry bottom, wall-fired	0.04 lb/ton	B	0.03 lb/ton	B	AP-42 Table 1.1-19 (9/98)
PC-fired, dry bottom, tangentially fired	0.04 lb/ton	B	0.08 lb/ton	B	AP-42 Table 1.1-19 (9/98)
PC-fired, wet bottom	0.05 lb/ton	B	0.08 lb/ton	E	AP-42 Table 1.1-19 (9/98)
Cyclone furnace	0.01 lb/ton	B	0.09 lb/ton	E	AP-42 Table 1.1-19 (9/98)
Spreader stoker	0.06 lb/ton	B	0.04 lb/ton	D	AP-42 Table 1.1-19 (9/98)
Overfeed stoker	0.06 lb/ton	B	0.04 lb/ton	E	AP-42 Table 1.1-19 (9/98)
Underfeed stoker	0.8 lb/ton	B	0.04 lb/ton	E	AP-42 Table 1.1-19 (9/98)
Fluidized bed combustor	0.06 lb/ton	E	3.5 lb/ton	B	AP-42 Table 1.1-19 (9/98)
Boilers - Lignite Atmospheric fluidized bed combustor	Not available	Not available	2.5 lb/ton	E	AP-42 Tables 1.7-1 and 1.7-4 (9/98)
Wood fuel/wood waste [c]	0.1 g/kg	Not available	0.07 g/kg	Not available	Environment and Climate Change Canada, 2020, Table A6.6-1

Table 4-10. Equipment-Specific Combustion Emission Factors for Boilers and Furnaces (Solid Fuels) [a], continued

Emission Factors Converted to tonne/tonne					
Source	**Methane**	**Emission Factor Rating [b]**	**Nitrous Oxide**	**Emission Factor Rating [b]**	**Source (version date)**
Boilers - Bituminous and Sub-bituminous Coal					
PC-fired, dry bottom, wall-fired	2.0E-05 tonne/tonne	B	1.5E-05 tonnes/tonne	B	AP-42 Table 1.1-19 (9/98)
PC-fired, dry bottom, tangentially fired	2.0E-05 tonnes/tonne	B	4.0E-05 tonnes/tonne	B	AP-42 Table 1.1-19 (9/98)
PC-fired, wet bottom	2.5E-05 tonnes/tonne	B	4.0E-05 tonnes/tonne	E	AP-42 Table 1.1-19 (9/98)
Cyclone furnace	5.0E-06 tonnes/tonne	B	4.5E-05 tonnes/tonne	E	AP-42 Table 1.1-19 (9/98)
Spreader stoker	3.0E-05 tonnes/tonne	B	2.0E-05 tonnes/tonne	D	AP-42 Table 1.1-19 (9/98)
Overfeed stoker	3.0E-05 tonnes/tonne	B	2.0E-05 tonnes/tonne	E	AP-42 Table 1.1-19 (9/98)
Underfeed stoker	4.0E-04 tonnes/tonne	B	2.0E-05 tonnes/tonne	E	AP-42 Table 1.1-19 (9/98)
Fluidized bed combustor	3.0E-05 tonnes/tonne	E	1.8E-03 tonnes/tonne	B	AP-42 Table 1.1-19 (9/98)
Boilers - Lignite					
Atmospheric fluidized bed combustor	Not available	Not available	1.25E-03 tonnes/tonne	E	AP-42 Tables 1.7-1 and 1.7-4 (9/98)
Wood fuel/wood waste [c]	1.0E-04 tonnes/tonne	Not available	7.0E-05 tonnes/tonne	Not available	Environment Canada, 2020, Table A6.6-1

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (EPA). *Compilation of Air Pollutant Emission Factors*, *Volume I: Stationary Point and Area Sources*, AP-42, (GPO 055-000-005-001), US EPA Office of Air Quality Planning and Standards, Fifth Edition, January 1995, with Supplements A and B, 1996; Supplement E, 1998.

[b] Emission factor rating pertains to the quality of the data; "A" has the best quality while "E" has the poorest quality.

[c] Environment Canada, *National Inventory Report: Greenhouse Gas Sources and Sinks in Canada 1990-2018 - Part 2,* Science and Technology Branch, Environment and Climate Change Canada, April 2020.

4.5.2 Internal Combustion Units

Table 4-11 summarizes CH_4 and N_2O emission factors for internal combustion units. These emission factors are given on a fuel input basis, but can be converted to a power output basis using the conversion factors for each type of engine given in Table 4-2.

The emission factors provided in Table 4-11 are generic factors, not model-specific. Model-specific emission factors for several Waukesha and CAT reciprocating engine models are provided in Appendix A.

Total organic compound (TOC) emission factors for diesel and gasoline IC engines (shown in Table 4-11) can be converted to CH_4 emission factors assuming the exhaust gas TOC contains 9 wt% CH_4 (based on AP-42, 10/96, Table 3.4-1).

A 2021 study measured unburned methane entrained in the exhaust from natural gas-fired compressor engines (“combustion slip”) at gathering and boosting stations in the U.S. In this study, measurements of CH_4 emissions from natural gas compressor engines were made at 67 gathering and boosting stations owned or managed by nine operators in 11 U.S. states in order to quantify combustion slip. Combustion slip was measured in support of a larger effort to quantify methane emissions from the U.S. natural gas gathering and boosting sector (Vaughn, et al., 2021). These measurement study emission factors for 4 cycle engines are included in Table 4-11.

As shown, the study CH_4 emission factor for 4 cycle, lean-burn engines is comparable to the AP-42 emission factor. However, for 4 cycle, rich-burn engines, the study emission factor is significantly lower than the AP-42 emission factor. This difference is likely due to nonselective catalytic reduction (NSCR) emission controls on all of the 4 cycle, rich-burn engines included in the measurement study, relative to no emission controls on engines that comprise the AP-42 emission factors (Vaughn, et al., 2021).

Table 4-11. Engines and Turbines Emission Factors

Original Units								
Source	**Methane**		**Emission Factor Rating**	**CH_4 Reference**	**Nitrous Oxide**		**Emission Factor Rating**	**N_2O Reference**
IC Engines								
2 cycle lean – Natural Gas	1.45	lb/10^6 Btu (HHV)	C	AP-42, Table 3.2-1 (7/00)	Refer to Table 4-6			
4 cycle lean – Natural Gas	5.77	kg/hr-unit	13.0 % uncertainty [f]	Vaughn, et al, 2021				
	1.25	lb/10^6 Btu (HHV)	C	AP-42, Table 3.2-2 (7/00)				
4 cycle rich – Natural Gas (with non-selective catalytic reduction) [e]	0.4	kg/hr-unit	67.5% uncertainty [f]	Vaughn, et al, 2021				
4 cycle rich – Natural Gas (uncontrolled)	0.23	lb/10^6 Btu (HHV)	C	AP-42, Table 3.2-3 (7/00)				
Gasoline	3.03	lb TOC/ 10^6 Btu (HHV) [a]	D,E	AP-42, Table 3.3-1 (10/96)				
Diesel	0.36	lb TOC/ 10^6 Btu (HHV) [a]	D,E	AP-42, Table 3.3-1 (10/96)				
Large Bore–Diesel (> 600 hp)	0.0081	lb/10^6 Btu (HHV) [b]	E	AP-42, Table 3.4-1 (10/96)				
Dual Fuel (95% Nat Gas/ 5%Diesel)	0.6	lb/10^6 Btu (HHV)	E	AP-42, Table 3.4-1 (10/96)				
Turbines (≥ 80% load) – Natural Gas								
Uncontrolled	0.0086	lb/10^6 Btu (HHV)/	C	AP-42, Table 3.1-2a (4/00)	0.003	lb/10^6 Btu (HHV) [c]	E	AP-42, Table 3.1-2a (4/00)

Table 4-11. Engines and Turbines Emission Factors, continued

Units Converted to US Basis [g]

Source	**Methane**		**Emission Factor Rating**	**CH_4 Reference**	**Nitrous Oxide**		**Emission Factor Rating**	**N_2O Reference**
IC Engines								
2 cycle lean – Natural Gas	0.00066	tonne/10^6 Btu (HHV)	C	AP-42, Table 3.2-1 (7/00)	Refer to Table 4-6			
	0.00073	tonne/10^6 Btu (LHV)						
4 cycle lean – Natural Gas	0.00052	tonne/10^6 Btu (HHV)	13.0 % uncertainty [f]	Vaughn, et al, 2021				
	0.00063	tonne/10^6 Btu (LHV)						
	0.00057	tonne/10^6 Btu (HHV)	C	AP-42, Table 3.2-2 (7/00)				
	0.00063	tonne/10^6 Btu (LHV)						
4 cycle rich – Natural Gas (with NSCR) [e]	4.5E-05	tonne/10^6 Btu (HHV)	67.5% uncertainty [f]	Vaughn, et al, 2021				
	5.0E-05	tonne/10^6 Btu (LHV)						
4 cycle rich – Natural Gas (uncontrolled)	0.00010	tonne/10^6 Btu (HHV)	C	AP-42, Table 3.2-3 (7/00);				
	0.00012	tonne/10^6 Btu (LHV)						
Gasoline	0.00137	tonne TOC/10^6 Btu (HHV) [a]	D, E	AP-42, Table 3.3-1 (10/96)				
	0.00145	tonne TOC/10^6 Btu (LHV) [a]						
Diesel	0.00016	tonne TOC/10^6 Btu (HHV) [a]	D, E	AP-42, Table 3.3-1 (10/96)				
	0.00017	tonne TOC/10^6 Btu (LHV) [a]						
Large Bore – Diesel (> 600 hp)	3.7E-06	tonne/10^6 Btu (HHV) [b]	E	AP-42, Table 3.4-1 (10/96)				
	3.9E-06	tonne/10^6 Btu (LHV) [b]						
Dual Fuel (95% NG/5% diesel)	0.00027	tonne/10^6 Btu (HHV)	E	AP-42, Table 3.4-1 (10/96)				
	0.00030	tonne/10^6 Btu (LHV) [d]						
Turbines (≥ 80% load) – Natural Gas								
Uncontrolled	3.9E-06	tonne/10^6 Btu (HHV)	C	AP-42, Table 3.1-2a (4/00)	1.4E-06	tonne/10^6 Btu (HHV) [c]	E	AP-42, Table 3.1-2a (4/00)
	4.3E-06	tonne/10^6 Btu (LHV)			1.5E-06	tonne/10^6 Btu (LHV) [c]		

Table 4-11. Engines and Turbines Emission Factors, continued

Units Converted to SI Basis [g]								
Source	**Methane**		**Emission Factor Rating**	**AP-42 Reference (version date)**	**Nitrous Oxide**		**Emission Factor Rating**	**Reference**
IC Engines								
2 cycle lean – Natural Gas	0.623	tonne/10^{12} J (HHV)	C	AP-42, Table 3.2-1 (7/00)	Refer to Table 4-6			
	0.693	tonne/10^{12} J (LHV)						
4 cycle lean – Natural Gas	0.494	tonne/10^{12} J (HHV)	13.0 % uncertainty [f]	Vaughn, et al, 2021				
	0.549	tonne/10^{12} J (LHV)						
	0.537	tonne/10^{12} J (HHV)	C	AP-42, Table 3.2-2 (7/00)				
	0.597	tonne/10^{12} J (LHV)						
4 cycle rich – Natural Gas (with NSCR) [e]	0.043	tonne/10^{12} J (HHV)	67.5% uncertainty [f]	Vaughn, et al, 2021				
	0.048	tonne/10^{12} J (LHV)						
4 cycle rich – Natural Gas (uncontrolled)	0.10	tonne/10^{12} J (HHV)	C	AP-42, Table 3.2-3 (7/00)				
	0.11	tonne/10^{12} J (LHV)						
Gasoline	1.30	tonne TOC/10^{12} J (HHV) [a]	D, E	AP-42, Table 3.3-1 (10/96)				
	1.37	tonne TOC/10^{12} J (LHV) [a]						
Diesel	0.15	tonne TOC/10^{12} J (HHV) [a]	D, E	AP-42, Table 3.3-1 (10/96)				
	0.16	tonne TOC/10^{12} J (LHV) [a]						
Large Bore – Diesel (> 600 hp)	0.0035	tonne/10^{12} J (HHV) [b]	E	AP-42, Table 3.4-1 (10/96)				
	0.0037	tonne/10^{12} J (LHV) [b]						
Dual Fuel (95% NG/5% diesel)	0.26	tonne/10^{12} J (HHV)	E	AP-42, Table 3.4-1 (10/96)				
	0.29	tonne/10^{12} J (LHV) [d]						
Turbines (≥ 80% load) – Natural Gas								
Uncontrolled	0.0037	tonne/10^{12} J (HHV)	C	AP-42, Table 3.1-2a (4/00)	0.0013	tonne/10^{12} J (HHV) [c]	E	AP-42, Table 3.1-2a (4/00)
	0.0041	tonne/10^{12} J (LHV)			0.0014	tonne/10^{12} J (LHV) [c]		

Footnotes and Sources:

Vaughn, T.L., et al. *Methane Exhaust Measurements at Gathering Compressor Stations in the United States*. Environ. Sci. Technol. 2021, 55,2,1190-1196. January 7, 2021.

U.S. Environmental Protection Agency (EPA). *Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources,* AP-42, (GPO 055-000-005-001), US EPA Office of Air Quality Planning and Standards, Fifth Edition, January 1995, with Supplements A, B, and C, 1996; Supplement D, 1998; Supplement E, 1999; and Supplement F, 2000.

[a] If the fuel composition is unknown, TOC factors shown above can be converted to CH_4 emission factors assuming the TOC contains 9 wt% CH_4 in the exhaust gas based on AP-42 (10/96). The emission factors include TOC emissions from the sum of exhaust, evaporative, crankcase, and refueling emissions. Emission factor rating D applies to exhaust emissions; emission factor rating E applies to evaporative, crankcase, and refueling emissions.

[b] Emission factor is based on TOC with 9% CH_4 by weight in the exhaust gas (based on AP-42, 10/96).

[c] Emission factor is based on limited source tests on a single turbine with water-steam injection.

[d] Emission factor was estimated assuming the fuel is a gas (i.e., assumed that HHV = LHV×0.90).

[e] All 4 cycle, rich-burn engines tested in the Vaughn, 2021 study were equipped with non-selective catalytic reduction (NSCR) controls.

[f] Based on 95% confidence interval.

[g] To convert between higher and lower heating value emission factors, the assumed conversion for gaseous fuels is: (EF, HHV) = (0.9) × (EF, LHV), and for solids or liquids the assumed conversion is (EF, HHV) = (0.95) × (EF, LHV).

Below is a default emission factor for methane emissions at an average gathering and boosting station developed by the U.S. EPA for consideration in the GHGI. The emission factor is based on the Vaughn, et al study (Vaughn, et al., 2021) measurement data of combustion slip and an estimate of the U.S. population of gathering and boosting engines (EPA Memo, 2019).

20.4 tonne CH_4/engine-year (Original Units) [a, b, c]

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (EPA) memo, *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2018: Updates Under Consideration for Natural Gas Gathering & Boosting Station Emissions*, November 2019, Table 4.

[b] Uncertainty is not specified for this value.

[c] EPA calculated a combustion slip CH4 EF by dividing the Zimmerle study's national combustion slip emissions by its national engine estimate.

Exhibit 4.8 shows an example calculation for CH_4 and N_2O emissions from an internal combustion engine.

EXHIBIT 4.8: Sample Calculation for Combustion Emissions Equipment Basis for Internal Combustion Device

INPUT DATA:
A 100-hp gasoline-fired IC engine is operated for 8000 hours at 90% load during the reporting year. Calculate the CH_4 and N_2O emissions from this source.

CALCULATION METHODOLOGY FOR CH_4:
1. *Calculate CH_4 emissions.* Because the equipment-specific CH_4 emission factor presented in Table 4-9 is on an energy input basis, the power output must be converted to energy input (E_{In}) basis. A conversion factor of 7,000 Btu/hp-hr is taken from Table 4-2. This calculation is shown in Exhibit 4.1 and is repeated below.

$$E_{In} = 100 \text{ hp} \times 0.90 \times \frac{8000 \text{ hr}}{\text{yr}} \times \frac{7000 \text{ Btu}}{\text{hp-hr}}$$

$$E_{In} = 5040 \times 10^6 \text{ Btu/yr (HHV)}$$

The emission factor presented in Table 4-9 for CH_4 is actually a factor for TOC. The exhaust gas TOC is assumed to contain 9 wt% CH_4 based on AP-42. The CH_4 emissions are calculated as:

$$E_{CH_4} = \frac{5040 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{0.00137 \text{ tonne TOC}}{10^6 \text{ Btu}} \times \frac{0.09 \text{ tonne } CH_4}{\text{tonne TOC}}$$

$$\underline{E_{CH_4} = 0.62 \text{ tonnes } CH_4/\text{yr}}$$

2. *Calculate N_2O emissions.* The N_2O emission factor for gasoline is provided on a volume basis. Nitrous oxide emissions are calculated by multiplying the emission factor provided in Table 4-11 (which refers to Table 4-6) by the quantity of energy consumed.

$$E_{N_2O} = \frac{5040 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{6.01 \times 10^{-7} \text{ tonne } N_2O}{10^6 \text{ Btu}}$$

$$\underline{E_{N_2O} = 0.00303 \text{ tonnes } N_2O/\text{yr}}$$

4.6 Mobile/Transportation Combustion Sources

Transportation combustion sources are the engines that provide motive power for vehicles used as part of petroleum operations. Transportation sources may include company fleet vehicles such as cars and trucks used for work-related personnel transport, as well as forklifts and other construction and maintenance equipment, rail cars, tanker trucks, ships, and barges used to transport crude and petroleum products, and mobile trucks and shovels used in oil sand mining operations.

The fossil fuel-fired IC engines used in transportation are a source of CO_2 emissions. Small quantities of CH_4 and N_2O are also emitted based on fuel composition, combustion conditions, and post-combustion control technology.

Estimating emissions from mobile sources can be complex, requiring detailed information on the types of mobile sources, fuel types, vehicle fleet age, maintenance procedures, operating conditions and frequency, emissions controls, and fuel consumption. EPA has developed a software model, MOtor Vehicle Emission Simulator (MOVES) [5], that accounts for these factors in calculating exhaust emissions (CO_2, HC, CO, NO_x, particulate matter, and toxics) for gasoline- and diesel-fueled vehicles. MOVES also estimates emissions for nonroad engines, equipment, and vehicles.

Figure 4-2 illustrates the methods available for estimating CO_2 emissions from mobile sources. The approaches for estimating CO_2 emissions range from the use of fuel consumption rates and

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[5] MOVES3 is the latest official version of MOVES. https://www.epa.gov/moves/latest-version-motor-vehicle-emission-simulator-moves, accessed June 30, 2021.

composition data to applying default fuel data to fuel-based emission factors or emission estimates based on vehicle distance traveled. Methane and N_2O emission factors are discussed separately.

Operators reporting under regulations with specific methodologies for mobile source combustion (for example, California's *Regulation for the Mandatory Reporting of Greenhouse Gas Emissions*, CARB, 2019) should use the approaches and default emission factors defined in the regulations rather than the approaches provided in this section.

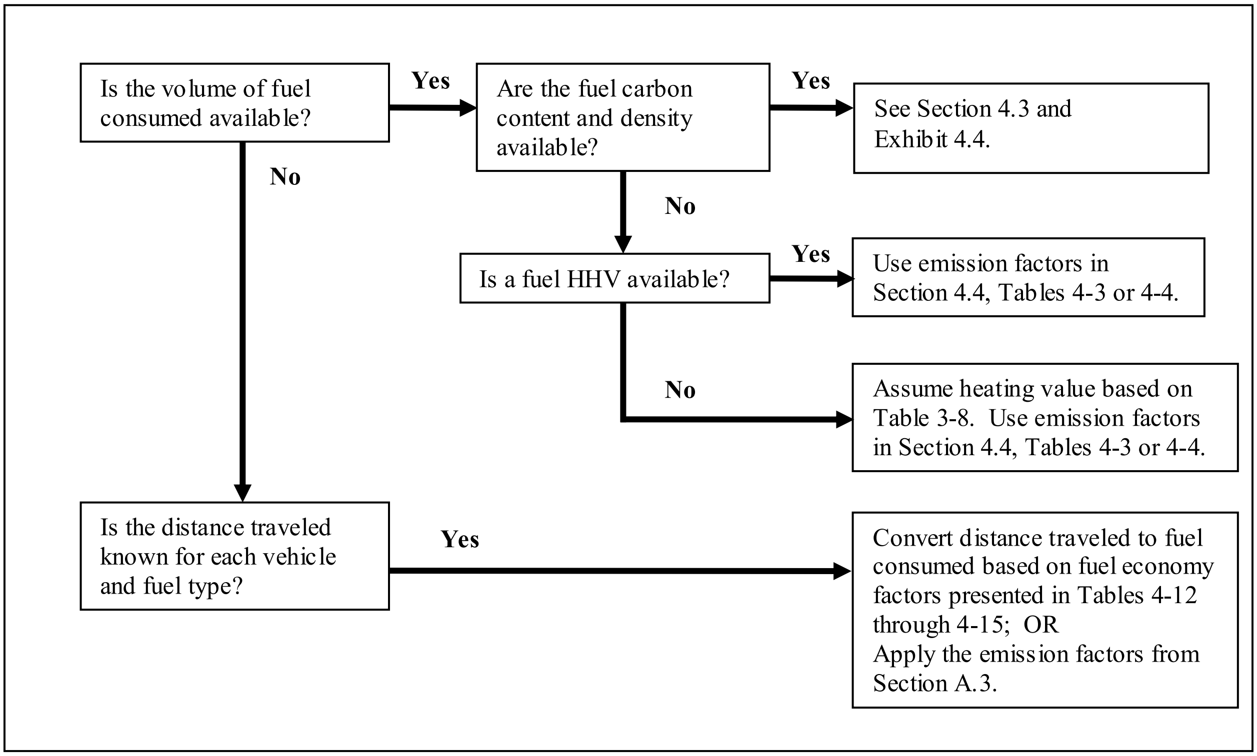

Figure 4-2. Calculation Approaches for Mobile Source CO_2 Emissions

4.6.1 Fuel Consumption Basis

Carbon Dioxide Emissions

As presented in Section 4.1 for stationary combustion, the fuel consumption approach for mobile sources is simply based on the volume of fuel combusted and either the carbon content of the fuel or the HHV. If the carbon content of the fuel is known, a material balance approach can be used based on an assumed conversion of carbon in the fuel to CO_2 (default of 100%). This type of calculation is demonstrated in Exhibits 4.4 and 4.5. As a rule of thumb, the carbon contents of different fuel types can be approximated from Table 3-8.

If the carbon content is unknown, fuel-specific emission factors provided in Table 4-3 can be used. These emission factors are based on the assumption that 100% of the fuel gas hydrocarbons is converted to CO_2. An example calculation is provided in Exhibit 4.6.

Some mobile sources combust biofuels such as ethanol and biodiesel, or biofuel blends such as E85 (85% ethanol and 15% gasoline) and B20 (20% biodiesel and 90% diesel). Combustion of biofuel blends results in emissions of both biogenic CO_2 and fossil-fuel CO_2. See Section 4.7 for a discussion of the special accounting consideration for biogenic fuels.

Automobiles/Passenger Vehicles

If the quantity of fuel consumed is unknown for land-based vehicles, fuel economy factors can be used to estimate the volumes. The most accurate fuel economy factors are vehicle- or model-specific. Fuel economy factors for vehicles sold in the U.S. from 1984 to the present can be obtained from the following EPA and DOE sponsored website:

http://www.fueleconomy.gov/feg/findacar.htm

In the absence of vehicle- or model-specific information, the economy factors shown in Table 4-12 can be used. Factors provided in Table 3-8 can be used to convert the volume of fuel used to an energy basis.

Diesel Freight

Fuel economy factors for diesel freight are based on the type of truck (semi-truck/articulated lorry, non-semi truck/rigid lorry)[6] and the percent weight laden. Average truck fuel economy (in liters/km) can be calculated using the following equations (Defra, 2005):

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[6] A semi truck/articulated lorry is a truck with two or more sections connected by a pivoting bar (e.g., tractor pulling a trailer). A non-semi truck/rigid lorry is a truck with a load bearing frame.

Table 4-12. Default Fuel Economy Factors for Different Types of Mobile Sources

Fuel Type	Vehicle Type	Fuel Economy	
		miles/gallon [a]	liters/100 km
Motor Gasoline	Small, gasoline automobile, city	26.0	9.0
	Small, gasoline automobile, highway	32.0	7.4
	Medium, gasoline automobile, highway	30.0	7.8
	Large gasoline automobile, highway	25.0	9.4
	Hybrid (Gasoline) Passenger Cars	31.2	7.5
	New Small Gasoline/Electric Hybrid [f]	56.0	4.2
	Gasoline Light-duty Trucks (Vans, Pickup Trucks, SUVs)	16.2	14.5
	Gasoline Heavy-duty Vehicles - rigid	8.8	26.7
	Gasoline Heavy-duty Vehicles – articulated [b]	5.9	39.9
	Bus - Gasoline [b]	5.0	47.0
Diesel Fuel	Diesel Passenger Cars	22.5	10.5
	Diesel Light-duty Trucks	16.2	14.5
	Diesel Medium- and Heavy-duty Vehicles	8.8	26.7
	Diesel Heavy-duty Vehicles – articulated [b]	5.9	39.9
	Bus - Diesel [b]	3.7	63.6
	Railroad (Class 1) [e]	296 Btu/ton-mile	---
Biodiesel (100%)	Biodiesel Passenger Cars, Small	22.5	10.5
	Biodiesel Passenger Cars, Large	8.8	26.7
	Biodiesel Light-duty Vehicles	16.2	14.5
	Biodiesel Medium- and Heavy-duty Vehicles	5.9	39.9
Compressed Natural Gas	CNG Light-duty Vehicles	16.2	14.5
	CNG Medium- and Heavy-duty Vehicles	8.8	26.7
	Bus - CNG [b]	2.4	98.0
Ethanol (100%)	Ethanol Light-duty Vehicles	16.2	14.5
	Ethanol Medium- and Heavy-duty Vehicles	8.8	26.7
LNG, LPG [b]	Heavy Duty Vehicle - Rigid	8.8	26.7
	Heavy Duty Vehicle - Articulated	5.9	39.9
Ethanol	Small vehicle - Ethanol	16.2	14.5
	Heavy vehicle - Ethanol	8.8	26.7
	Bus - Ethanol [b]	5.0	47.0

Fuel Type	**Vehicle Type**	**Fuel Economy**	
		miles/gallon [a]	**liters/100 km**
Jet Fuel, Kerosene	Air Travel (Jet Fuel, Kerosene - Domestic Carriers) [c]	0.38	--
	Boeing 747 – kerosene [d]	5.0	47.0
Unspecified [c]	Waterborne - Domestic Commerce [c]	514 Btu/ton-mile	---

Footnotes and Sources:

[a] Data from the following, unless otherwise indicated: GHG Emissions Calculation Tool, GHG Emissions Calculation Tool_0.xlsx, Emission Factors, S-1 Mobile Combustion, World Resources Institute.

[b] Emission Factors from Cross-Sector Tools, Emission_Factors_from_Cross_Sector_Tools_March_2017.xlsx, Transport Vehicle Distance, World Resources Institute, March 2017.

[c] EPA, Climate Leaders Greenhouse Gas Inventory Protocol Core Module Guidance: *Direct Emissions from Mobile Combustion Sources*, Table 4, May 2008.

[d] Boeing Company. http://boeing.com/commercial/747/#/design-highlights/ , accessed June 28, 2021.

[e] Bureau of Transportation Stattistics, Table 6-10 Energy Intensities of Domestic Freight Transportation Modes: 2007-2013, January 5, 2016.

[f] World Resources Institute and World Business Council for Sustainable Development (WRI/WBCSD) *Calculating CO2 Emissions from Mobile Sources. Guidance to calculation worksheets v1.3*. Table 4. March 2005. File: co2-mobile.pdf available through www.ghgprotocol.org, October 2007.

$$\text{Fuel Economy}_{\text{Non-Semi Truck/Rigid Lorry}}(\text{liters/km})=0.236+0.104\times\frac{\%\text{ weight laden}}{100} \qquad \text{(Equation 4-18)}$$

where:

% weight laden = the extent to which the vehicle is loaded to its maximum carrying capacity.

$$\text{Fuel Economy}_{\text{Semi Truck/Articulated Lorry}}(\text{liters/km})=0.311+0.137\times\frac{\%\text{ weight laden}}{100} \qquad \text{(Equation 4-19)}$$

Fuel economies for multiple operational settings are provided in Table 4-13. If the % weight laden is unknown, 50% weight laden should be used as an average figure (Defra, 2005).

Table 4-13. Default Fuel Economy Factors for Diesel Freight Mobile Sources [a]

Truck Type	% Weight Laden	Fuel Economy	
		liters/km	gallons/mile
Non-Semi truck (Rigid Lorry)	0%	0.236	0.100
	25%	0.262	0.111
	50%	0.288	0.122
	75%	0.314	0.133
	100%	0.340	0.145
Semi truck (articulated lorry)	0%	0.311	0.132
	25%	0.345	0.147
	50%	0.379	0.161
	75%	0.414	0.176
	100%	0.448	0.190

Footnote and Source:

[a] Department for Environment, Food and Rural Affairs (Defra). *Guidelines for company reporting on Greenhouse Gas Emissions, Annexes updated July 2005*, Table 10.

Marine Vessels

Marine vessel fuel consumption is based on the type of vessel and the gross registered tonnage. Average marine vessel fuel consumption is presented in Table 4-14. Although the figures presented in Table 4-14 are not engine specific, fuel consumption will vary by engine (i.e., main engines consume more fuel than auxiliary engines). In the event that equipment-specific data are used to calculate emissions, fuel consumption should be split among engine types using the consumption percentages presented in Table 4-15.

Table 4-14. Default Fuel Consumption for Marine Vessels [a]

Ship type	Average Consumption (tonne/day)	Consumption at Full Power (tonne/day) [b]
Solid bulk carriers	33.8	20.186 + (0.00049 x GRT)
Liquid bulk carriers	41.8	14.685 + (0.00079 x GRT)
General cargo	21.3	9.8197 + (0.00143 x GRT)
Container	65.9	8.0552 + (0.00235 x GRT)
Passenger/roll-on/roll-off (Ro-Ro)/cargo	32.3	12.834 + (0.00156 x GRT)
High speed ferry	80.4	39.483 + (0.00972 x GRT)
Inland cargo	21.3	9.8197 + (0.00143 x GRT)
Tugs	14.4	5.6511 + (0.01048 x GRT)
Other ships	26.4	9.7126 + (0.00091 x GRT)
All ships	32.8	16.263 + (0.001 x GRT)

Footnotes and Sources:

[a] IPCC, *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, *Volume 2, Chapter 3 (Mobile Combustion),* Table 3.5.6, 2006.

[b] Fuel consumption is a function of Gross Registered Tonnage (GRT), a measure of the total internal volume of a vessel.

Table 4-15. Default Fuel Consumption by Engine Type [a]

Ship Type	Main Engine Consumption (%)	Avg. Number of Aux. Engines Per Vessel	Aux. Engine Consumption (%)
Bulk carriers	98%	1.5	2%
Combination carriers	99%	1.5	1%
Container vessels	99%	2	1%
Dry cargo vessels	95%	1.5	5%
Offshore vessels	98%	1	2%
Ferries/passenger vessels	98%	2	2%
Reefer vessels	97%	2	3%
RoRo vessels	99%	1.5	1%
Tankers	99%	1.5	1%
Miscellaneous vessels	98%	1	2%
Totals	98%		2%

Footnote and Source:

[a] IPCC, *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, Volume 2, Chapter 3 (Mobile Combustion), Table 3.5.5, June 2019.

Methane and Nitrous Oxide Emissions

Methane emissions from transportation fuel consumption can also be estimated using a mass balance and assuming a certain CH_4 destruction efficiency for the CH_4 content of the fuel. Methane formation from the combustion of gasoline and diesel, the most commonly used transportation fuels, typically only contributes around 1% of CO_2 equivalent emissions from the road transport sector; nitrous oxide emissions are not much higher, contributing only 2-3% of CO_2 equivalent emissions (IPCC, 2006).

Simplified emission factors for CH_4 and N_2O emissions from automobiles and other passenger vehicles are provided in Table 4-16.

Table 4-16. Mobile Source Combustion Emission Factors [a]

	Methane Emission Factors			Nitrous Oxide Emission Factors		
Mode	**Original Value [a] g/L fuel**	**Converted to tonnes/1,000 gal fuel**	**Converted to tonnes/m^3 fuel**	**Original Value [a] g/L fuel**	**Converted to tonnes/1,000 gal fuel**	**Converted to tonnes/m^3 fuel**
Road Transport						
Gasoline Vehicles						
Light-duty Gasoline Vehicles						
Tier 2	0.14	5.3E-04	1.4E-04	0.022	8.3E-05	2.2E-05
Tier 1	0.23	8.7E-04	2.3E-04	0.47	1.8E-03	4.7E-04
Tier 0	0.32	1.2E-03	3.2E-04	0.66	2.5E-03	6.6E-04
Oxidation Catalyst	0.52	2.0E-03	5.2E-04	0.20	7.6E-04	2.0E-04
Non-catalytic Controlled	0.46	1.7E-03	4.6E-04	0.028	1.1E-04	2.8E-05
Light-duty Gasoline Trucks						
Tier 2	0.14	5.3E-04	1.4E-04	0.022	8.3E-05	2.2E-05
Tier 1	0.24	9.1E-04	2.4E-04	0.58	2.2E-03	5.8E-04
Tier 0	0.21	7.9E-04	2.1E-04	0.66	2.5E-03	6.6E-04
Oxidation Catalyst	0.43	1.6E-03	4.3E-04	0.20	7.6E-04	2.0E-04
Non-catalytic Controlled	0.56	2.1E-03	5.6E-04	0.028	1.1E-04	2.8E-05
Heavy-duty Gasoline Vehicles						
Three-way Catalyst	0.068	2.6E-04	6.8E-05	0.20	7.6E-04	2.0E-04
Non-catalytic Controlled	0.29	1.1E-03	2.9E-04	0.047	1.8E-04	4.7E-05
Uncontrolled	0.49	1.9E-03	4.9E-04	0.084	3.2E-04	8.4E-05
Motorcycles						
Non-catalytic Controlled	0.77	2.9E-03	7.7E-04	0.041	1.6E-04	4.1E-05
Uncontrolled	2.3	8.7E-03	2.3E-03	0.048	1.8E-04	4.8E-05
Diesel Vehicles						
Light-duty Diesel Vehicles						
Advanced Control [b]	0.051	1.9E-04	5.1E-05	0.22	8.3E-04	2.2E-04
Moderate Control	0.068	2.6E-04	6.8E-05	0.21	7.9E-04	2.1E-04
Uncontrolled	0.10	3.8E-04	1.0E-04	0.16	6.1E-04	1.6E-04
Light-duty Diesel Trucks						
Advanced Control [b]	0.068	2.6E-04	6.8E-05	0.22	8.3E-04	2.2E-04
Moderate Control	0.068	2.6E-04	6.8E-05	0.21	7.9E-04	2.1E-04
Uncontrolled	0.085	3.2E-04	8.5E-05	0.16	6.1E-04	1.6E-04
Heavy-duty Diesel Vehicles						
Advanced Control	0.11	4.2E-04	1.1E-04	0.151	5.7E-04	1.5E-04
Moderate Control	0.14	5.3E-04	1.4E-04	0.082	3.1E-04	8.2E-05
Uncontrolled	0.15	5.7E-04	1.5E-04	0.075	2.8E-04	7.5E-05

	Methane Emission Factors			**Nitrous Oxide Emission Factors**		
Mode	**Original Value [a] g/L fuel**	**Converted to tonnes/1,000 gal fuel**	**Converted to tonnes/m^3 fuel**	**Original Value [a] g/L fuel**	**Converted to tonnes/1,000 gal fuel**	**Converted to tonnes/m^3 fuel**
Natural Gas Vehicles	9E-03	3.4E-05	9.0E-06	6E-05	2.3E-07	6.0E-08
Propane Vehicles	0.64	2.4E-03	6.4E-04	0.028	1.1E-04	2.8E-05
Off-road						
Off-road Gasoline 2-stroke	10.61	4.0E-02	1.1E-02	0.013	4.9E-05	1.3E-05
Off-road Gasoline 4-stroke	5.08	1.9E-02	5.1E-03	0.064	2.4E-04	6.4E-05
Off-road Diesel <19kW	0.073	2.8E-04	7.3E-05	0.022	8.3E-05	2.2E-05
Off-road Diesel >=19kW, Tier 1 - 3	0.073	2.8E-04	7.3E-05	0.022	8.3E-05	2.2E-05
Off-road Diesel >= 19kW, Tier 4	0.073	2.8E-04	7.3E-05	0.227	8.6E-04	2.3E-04
Off-road Natural Gas	0.0088	3.3E-05	8.8E-06	0.00006	2.3E-07	6.0E-08
Off-road Propane	0.64	2.4E-03	6.4E-04	0.087	3.3E-04	8.7E-05
Railways						
Diesel Train	0.15	5.7E-04	1.5E-04	1.0	3.8E-03	1.0E-03
Marine						
Gasoline	0.22	8.3E-04	2.2E-04	0.063	2.4E-04	6.3E-05
Diesel	0.25	9.5E-04	2.5E-04	0.072	2.7E-04	7.2E-05
Light Fuel Oil	0.26	9.8E-04	2.6E-04	0.073	2.8E-04	7.3E-05
Heavy Fuel Oil	0.29	1.1E-03	2.9E-04	0.082	3.1E-04	8.2E-05
Kerosene	0.25	9.5E-04	2.5E-04	0.071	2.7E-04	7.1E-05
Aviation						
Aviation Gasoline	2.2	8.3E-03	2.2E-03	0.23	8.7E-04	2.3E-04
Aviation Turbo Fuel	0.029	1.1E-04	2.9E-05	0.071	2.7E-04	7.1E-05
Renewable Fuels						
Ethanol	--[c]	--[c]	--[c]	--[c]	--[c]	--[c]
Biodiesel	--[d]	--[d]	--[d]	--[d]	--[d]	--[d]

Footnotes and Sources:

[a] Environment Canada, *National Inventory Report: Greenhouse Gas Sources and Sinks in Canada - 2018*, Part 2, Table A6.1–13, 2020.

[b] Advanced control diesel emission factors are used for Tier 2 diesel vehicle populations.

[c] Gasoline CH_4 and N_2O emission factors (by mode and technology) are used for ethanol.

[d] Diesel CH_4 and N_2O emission factors (by mode and technology) are used for biodiesel.

An example calculation illustrating how to estimate vehicle emissions is shown in Exhibit 4.12.

EXHIBIT 4.12: Sample Calculation for Combustion Emissions from Vehicles

INPUT DATA:
A fleet of heavy-duty (HD) diesel freight trucks travels 1,000,000 miles during the year. The trucks are equipped with advance control systems. Calculate the CO_2, CH_4, and N_2O emissions.

EXHIBIT 4.12: Sample Calculation for Combustion Emissions from Vehicles, continued

CALCULATION METHODOLOGY:
The CH_4 and N_2O emission factors provided in Table 4-16 are given in terms of volumetric fuel consumed. The fuel usage of the fleet is unknown so the first step in the calculation is to convert from miles traveled to a volume of diesel fuel consumed basis. This calculation is performed using the default fuel economy factor of 8.8 miles/gallon for diesel heavy trucks provided in Table 4-12.

$$\text{Fuel Consumed} = \frac{1{,}000{,}000 \text{ miles}}{\text{yr}} \times \frac{\text{gal diesel}}{8.8 \text{ miles}} = 113{,}636 \text{ gal diesel/yr}$$

1. *Calculate the CO_2 emissions.* Carbon dioxide emissions are estimated using a fuel-based factor provided in Table 4-3. This factor is provided on a heat basis so the fuel consumption must be converted to an energy input basis. This conversion is carried out using a recommended diesel heating value of 5.83×10^6 Btu/bbl (HHV), given in Table 3-8 of this document. Thus, the fuel heat rate is:

$$\text{Fuel Consumed} = \frac{113{,}636 \text{ gal}}{\text{yr}} \times \frac{\text{bbl}}{42 \text{ gal}} \times \frac{5.83 \times 10^6 \text{ Btu}}{\text{bbl}} = 1.58 \times 10^{10} \text{ Btu/yr (HHV)}$$

CO_2 emissions are calculated as using the fuel basis CO_2 emission factor for diesel fuel ("Gas/Diesel Oil") provided in Table 4-3, assuming 100% oxidation of fuel carbon to CO_2:

$$E_{CO_2} = \frac{1.58 \times 10^{10} \text{ Btu}}{\text{yr}} \times \frac{0.0822 \text{ tonne } CO_2}{10^6 \text{ Btu}}$$

$$E_{CO_2} = 1{,}297 \text{ tonnes } CO_2/\text{yr}$$

2. *Calculate the CH_4 and N_2O emissions.* Methane and N_2O emissions are calculated using the CH_4 and N_2O emission factors provided in Table 4-16 for "Heavy-Duty Diesel Vehicles, Advance Control."

EXHIBIT 4.12: Sample Calculation for Combustion Emissions from Vehicles, continued

$$E_{CH_4} = \frac{113{,}636 \text{ gal}}{\text{yr}} \times \frac{4.2 \times 10^{-4} \text{ tonne } CH_4}{1000 \text{ gal}}$$

$$E_{CH_4} = 0.048 \text{ tonnes } CH_4/\text{yr}$$

$$E_{N_2O} = \frac{113{,}636 \text{ gal}}{\text{yr}} \times \frac{5.7 \times 10^{-4} \text{ tonne } CH_4}{1000 \text{ gal}}$$

$$E_{N_2O} = 0.064 \text{ tonnes } N_2O/\text{yr}$$

This sample calculation illustrates that the CH_4 and N_2O emissions are small when compared to CO_2.

Combustion slip, or 'methane slip', in marine vessels that use LNG as marine fuel has been studied by researchers, due to the increasing number of vessels utilizing LNG as main fuel. Both on-board and test-bed emission measurements, data from the engine manufacturer's own test-bed measurements and engine acceptance test provided the basis for a study on methane slip from LNG-fueled marine vessels (Ushakov, et al, 2019). The methane emission factors that were developed for LNG marine vessels are presented below in Table 4-17.

Table 4-17. Methane Emission Factors for Marine LNG-Fueled Engines [a]

Gas Engine Type	Methane Emission Factor				
	Original Units	Converted to tonnes $CH_4/10^{12}$ J (HHV) [b]	Converted to tonnes $CH_4/10^{12}$ J (LHV) [c]	Converted to tonnes CH_4/MMBtu (HHV) [b]	Converted to tonnes CH_4/MMBtu (LHV) [c]
Lean-Burn Spark Ignition (LBSI)	23.2 g CH_4/kg LNG	0.4241	0.4696	4.47E-04	4.95E-04
	4.1 g CH_4/kWh	--	--	--	--
Low Pressure Dual Fuel (LPDF)	40.9 g CH_4/kg LNG	0.7477	0.8279	7.89E-04	8.74E-04
	6.9 g CH_4/kWh	--	--	--	--

Footnotes and Sources:

[a] Ushakov, S., Stenersen, D. & Einang, P.M. *Methane slip from gas fuelled ships: a comprehensive summary based on measurement data*. Journal of Marine Science and Technology, 24, 1308–1325 (2019).

[b] Based on gross heating value of 54.7 MJ/kg.

[c] Based on net heating value of 49.4 MJ/kg.

An example calculation illustrating how to estimate marine vessel emissions is shown in Exhibit 4.13.

EXHIBIT 4.13: Sample Calculation for Combustion Emissions from Marine Vessels

INPUT DATA:
A fleet of 17 diesel-powered tankers operated 90 percent of the year at sea. The fuel consumption and Gross Registered Tonnage for each ship is unknown. Calculate the CO_2, CH_4, and N_2O emissions.

CALCULATION METHODOLOGY:
1. *Calculate the CO_2 emissions.* The fuel usage of the fleet is unknown so the first step in the calculation is to convert from days of operation to a volume of diesel fuel consumed basis. This calculation is performed using the default fuel economy factor provided in Table 4-14 for liquid bulk carriers. Note that the fuel economy factor is in terms of tonnes/day, and must be converted to a volume basis using the density of the fuel provided in Table 3-8 (for "Distillate Oil").

$$\text{Fuel Consumed} = 17 \text{ tankers} \times 0.9 \times \frac{365 \text{ days}}{\text{yr}} \times \frac{41.8 \text{ tonnes diesel}}{\text{day-tanker}} \times \frac{\text{m}^3}{847.31 \text{ kg diesel}} \times \frac{1000 \text{ kg}}{\text{tonne}}$$

$$\text{Fuel Consumed} = 275{,}498 \text{ m}^3 \text{ diesel consumed/yr}$$

Carbon dioxide emissions are estimated using a fuel-based factor provided in Table 4-3. This factor is provided on a heat basis so the fuel consumption must be converted to an energy input basis. This conversion is carried out using a recommended diesel heating value of 3.87×10^{10} J/m^3 (HHV) (for "Distillate Oil"), provided in Table 3-8.

$$\text{Fuel consumed} = \frac{275{,}498 \text{ m}^3}{\text{yr}} \times \frac{3.87 \times 10^{10} \text{ J}}{\text{m}^3} = 1.07 \times 10^{16} \text{ J/yr (HHV)}$$

Carbon dioxide emissions are calculated using the fuel basis CO_2 emission factor for diesel fuel ("Distillate Fuel") shown in Table 4-3, assuming 100% oxidation of fuel carbon to CO_2:

$$E_{CO_2} = \frac{1.07 \times 10^{16} \text{ J}}{\text{yr}} \times \frac{69.4 \text{ tonne } CO_2}{10^{12} \text{ J}}$$

$$E_{CO_2} = 742{,}580 \text{ tonnes } CO_2/\text{yr}$$

EXHIBIT 4.13: Sample Calculation for Combustion Emissions from Marine Vessels, continued

2. *Calculate the CH_4 and N_2O emissions.* Methane and N_2O emissions are calculated using the CH_4 and N_2O emission factors provided in Table 4-16 for "Diesel Ships."

$$\mathrm{E_{CH_4}} = \frac{275{,}498\ \mathrm{m^3}}{\mathrm{yr}} \times \frac{2.5 \times 10^{-4}\ \mathrm{tonne\ CH_4}}{\mathrm{m^3}}$$

$$\mathrm{E_{CH_4}} = 68.9\ \mathrm{tonnes\ CH_4/yr}$$

$$\mathrm{E_{N_2O}} = \frac{275{,}498\ \mathrm{m^3}}{\mathrm{yr}} \times \frac{7.2 \times 10^{-5}\ \mathrm{tonne\ CH_4}}{\mathrm{m^3}}$$

$$\mathbf{E_{N_2O} = 19.8\ tonnes\ N_2O/yr}$$

4.6.2 Operational Basis

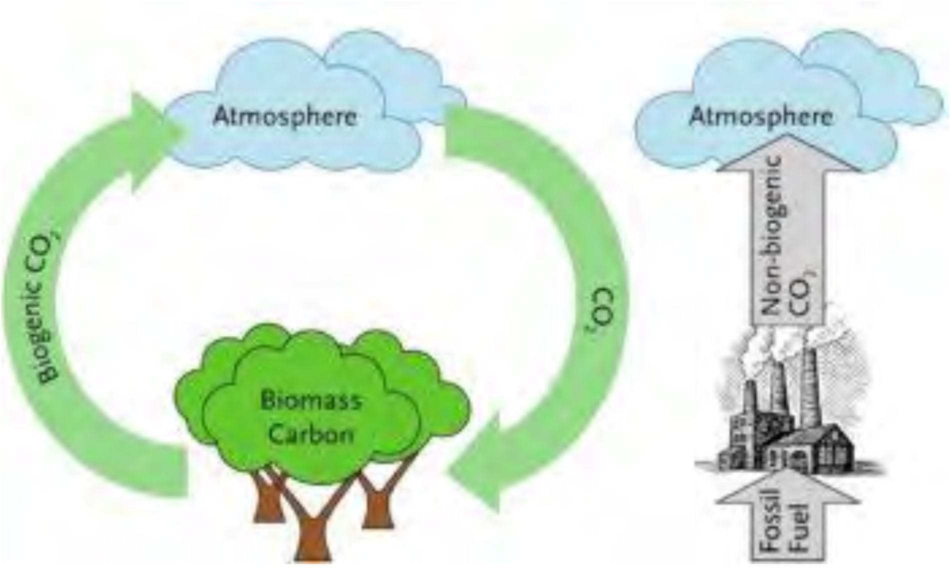
If mobile source fuel consumption is not available, or operational parameters cannot be used in such a way as to obtain fuel consumed, the alternate method for calculating emissions from mobile sources is to use operational data, such as distance traveled or power output. This method is described in detail in Appendix A.

4.7 Special Considerations for the Combustion of Biogenic Fuels

According to the U.S. Energy Information Administration (EIA 2021a), in 2020, biomass provided about 4,532 trillion British thermal units (TBtu), which equaled about 4.9% of total U.S. primary energy consumption. Most of that energy came from wood and wood-derived biomass and from biofuels (mainly ethanol).

As mentioned previously, there are special consideration associated with the combustion of biogenic fuels. This is due mainly to the fundamental difference between combusting fossil fuels and biogenic fuels as described by the IEA (IEA 2021) and illustrated in Figure 4-3. When fossil fuels are burned, carbon is released that has been locked up in the ground for millions of years while burning biogenic fuels emits carbon that is part of the biogenic carbon cycle. Put another way, combusting fossil fuels increases the amount of carbon in the "biosphere-atmosphere system" whereas the biogenic carbon cycle operates within this system, i.e., combustion of biogenic fuels simply returns to the atmosphere the carbon that was absorbed as the plants grew.

Due to the fundamental difference described above, current guidance from the 2019 Refinement to the 2006 IPCC Guidelines (IPCC 2019) and various other sources (WBCSD/WRI, WRI 2005, EPA 2020a) recommends that CO_2 emissions from the combustion of biogenic fuels must be tracked separately from fossil CO_2 emissions. Biogenic fuel CO_2 emissions should not be included in the overall CO_2-equivalent emissions inventory for organizations following this guidance. CH_4 and N_2O emission from biogenic fuel combustion are included in the overall CO_2-equivalent emission inventories. *The Greenhouse Gas Protocol - A Corporate Accounting and Reporting Standard* (GHG Protocol) (WBCSD/WRI) requires that biogenic combustion CO_2 be reported separately from other scopes because of the recognition that the accounting of terrestrial carbon stock changes with the harvesting and combustion of biomass may fall outside the organizational boundaries of a company (WBCSD/WRI, WRI 2005).



Source: IEA 2021

Figure 4-3. Fossil Versus Biogenic CO_2

Similar to the reporting of emissions from fossil fuel combustion, operators reporting under regulations with specific methodologies addressing biogenic fuel combustion should use those methods. The U.S. EPA Mandatory Greenhouse Gas Reporting program, codified in at 40 CFR Part 98 includes emission factors for biogenic fuels, that are reported above in Table 4-5 for CO_2 and in Table 4-8 for CH_4 and N_2O. The 40 CFR Part 98 regulations, at 40 CFR 98.33(e), also include requirements specific to biogenic CO_2 emissions from combustion of biomass with other fuels (either co-fired or blended fuels).

EPA provides specific guidance for several transportation fuels that are actually blends of fossil and non-fossil fuels (EPA, 2020). EPA provides an example for E85, which is an ethanol (biomass fuel) and gasoline (fossil fuel) blend containing up to 83 percent ethanol. EPA also notes that the majority of motor gasoline used in the United States is made up of a blend of gasoline and ethanol. The typical blend is E10 (10 percent ethanol and 90 percent gasoline), but the content of ethanol in gasoline can vary by location and by year. EPA recommends that an organization report both types of CO_2 emissions, biomass CO_2 and fossil CO_2, if blended fuels are used. The blend percentage can be used to estimate the quantity of fossil fuel and biofuel. And then separate fossil and biomass emission factors can be applied to the fuel mix.

EPA also recommends that if specific biofuel content data is not available, then an ethanol content of 10 percent can be assumed for gasoline. A national average ethanol content can be used for E85, which is available from the EIA *Annual Energy Outlook*. Currently, the EIA assumes a national annual average of 74 percent in its projections (EIA, 2021)

Finally EPA recommends that for organizations that operate "flex-fuel" vehicles, which can use either fossil fuels or a biofuel blend, and the it is uncertain which fuel is used in these vehicles, fossil fuel should be assumed.

4.8 Other Miscellaneous Combustion Source Emissions

Other miscellaneous combustion sources include coke calcining kilns and welding.[7] Combustion emissions from these sources vary widely from process to process. Thus, there is not a set of published emission factors associated with these equipment/processes. General emission estimation approaches for fuel combustion, combined with site-specific data and/or engineering judgment, are recommended for determining these emissions.

Methane emissions from these sources can be estimated from a mass balance by assuming a certain CH_4 destruction efficiency. Carbon dioxide emissions can be estimated by mass balance using an assumed conversion of carbon in the fuel gas to CO_2. Alternatively, the external combustion emission factors given by fuel usage (described in Section 4.4) can be used for estimating CO_2 emissions. For some sources, N_2O emissions can be estimated by applying an emission factor from Tables 4-8 through 4-10. However, the factors provided in Tables 4-8 through 4-10 may not be applicable for all miscellaneous combustion sources.

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[7] Welding processes may involve the combustion of a supplemental fuel (e.g., acetylene).

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Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Natural Gas and Oil Industry

Section 5 – Waste Gas Disposal Emissions Estimation Methods

November 2021

Table of Contents

List of Tables

List of Figures

5.0 WASTE GAS DISPOSAL EMISSIONS ESTIMATION METHODS

Various combustion devices (e.g. flares incinerators, oxidizers, etc.) are used to dispose of waste gas in the oil and natural gas industry. Like the other combustion sources discussed in Section 4, CO_2, CH_4, and N_2O are produced and/or emitted as a result of the combustion process. Carbon dioxide emissions are the by-product of the oxidation of hydrocarbons during combustion. Nearly all of the waste gas carbon is converted to CO_2 during the combustion process. Methane emissions may result from the incomplete combustion of hydrocarbons or a slip stream of CH_4 in the waste gas. Incomplete combustion also results in other products such as carbon monoxide (CO) and volatile organic compounds (VOC)[1].

For waste gas disposal, N_2O is formed during combustion by a complex series of reactions. Because its formation is dependent upon many factors, N_2O emissions can vary widely from unit to unit, and even vary within the same unit for different operating conditions. Typically the conditions that favor formation of N_2O also favor CH_4 emissions. Overall, CH_4 and N_2O emissions from the disposal of waste gas are significantly less than CO_2 emissions, on a CO_2 equivalent basis.

The GHG calculation methods for waste gas disposal differ from other combustion due to the combustion conditions, as well as the variability in the waste gas composition and flow compared to the mostly uniform properties of fuels used for combustion. The following sections present GHG calculation methodologies for flares and incinerators, oxidizers, and vapor combustion units.

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[1] VOC excludes non-reactive hydrocarbons, such as methane and ethane. The definition of VOC is provided in the Glossary.

5.1 Flare Emissions

Flares are used in all segments of the oil and gas industry to manage the disposal of unrecoverable natural gas via combustion of hydrocarbon products from routine operations, upsets, or emergencies. A wide variety of flare types are used in the industry, ranging from small open-ended pipes at production wellheads, to large horizontal or vertical flares with pilots and air- or steam-assist, such as those at refineries. Emissions of CO_2 and N_2O are formed as by-products of combustion, and CH_4 emissions may result from incomplete combustion or during the time periods where there is no flame at the flare tip due to operational problems. [2]

Figure 5-1 shows a simplified diagram of a flare system, which is comprised of combustion of the following streams:

- Waste gas routed from the process to the flare for disposal;
- Purge or 'sweep' gas utilized to avoid air infiltration into the flare stack, as part of the safety system;
- Pilot gas necessary for positive ignition of the flare gas; and
- In some cases, auxiliary or supplemental fuel used in the flare to assist with hydrocarbon combustion when the flare gas stream is below the flammability range to produce a stable flame (U.S. EPA, Air Pollution Control Cost Manual Section 3.2, 2019).

It should be noted that the gas composition of the waste stream being flared, and that of the purge and pilot gas, are typically different (e.g., fuel gas used for purge and pilot) as reflected in the CO_2 and CH_4 emission calculations.

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[2] Flares that are not operating (i.e., no flame) are treated as vented sources (see Section 6).

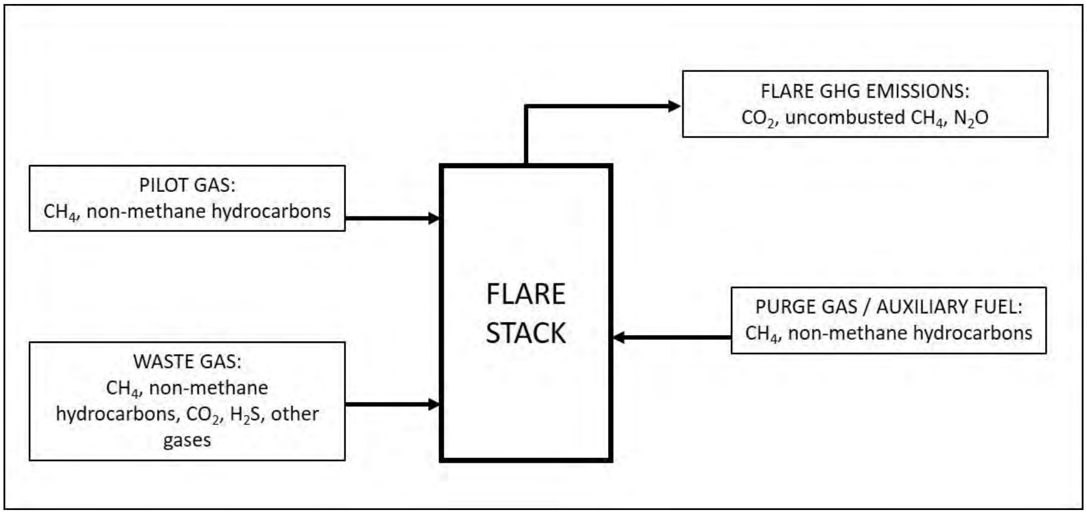

Figure 5-1. Simplified Flare System Diagram

5.1.1 Data Sources for Quantifying Flare Emissions

The flowchart in Figure 5-2 provides guidance on the preferred data sources for quantifying emissions from flares.

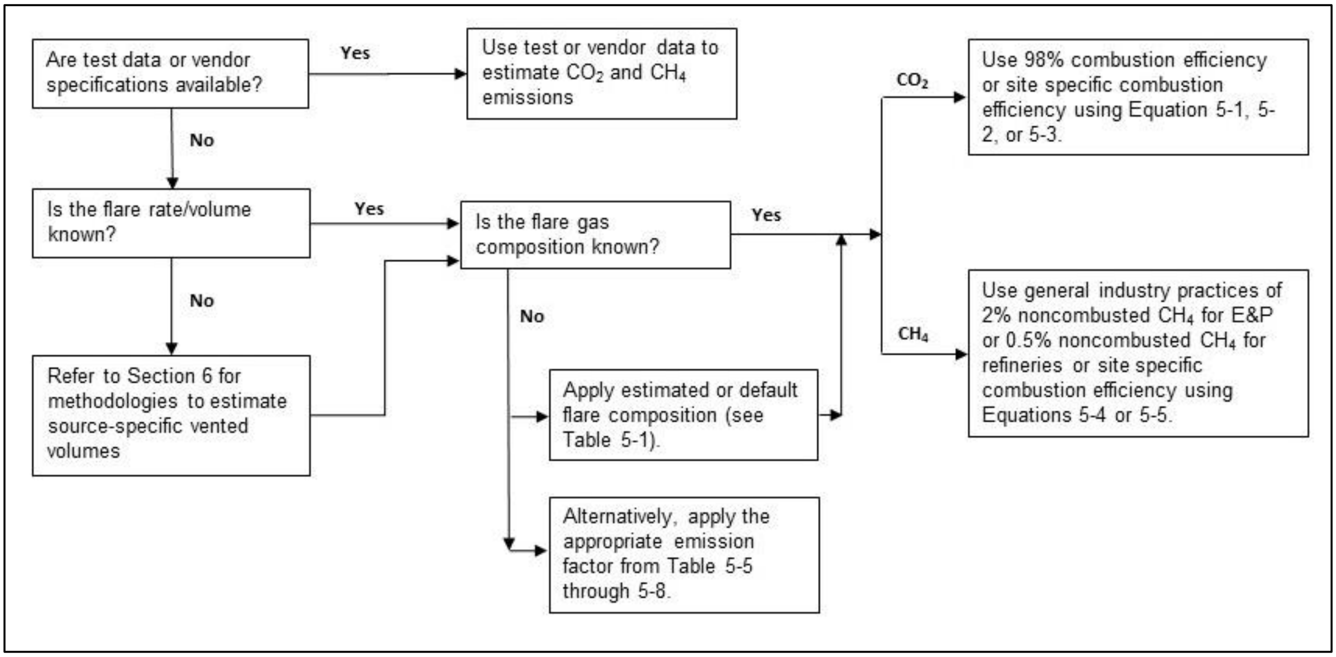

Figure 5-2. Data Sources for Calculating Gas Flare Emissions

As shown in Figure 5-2 above, the API *Compendium* recommends test data or vendor-specific information for estimating flare emissions from gas streams because this information is of higher quality than engineering estimates or default data. Because the availability of test or vendor data is limited, an alternative approach is to estimate flare emissions based on:

- Volume of gas flared;
- Composition of gas flared;
- Flare combustion efficiency; and
- Methane destruction efficiency.

5.1.1.1 Flared Gas Volume

Where available, metered flow rates of flared gas streams are preferred. An alternative to metered flow rates used by some operators is the monitoring of valve positions for streams routed to a flare, along with engineering estimates of flow rate through the valve based on orifice size, temperature and pressure. These measurement-based approaches to monitoring flared gas volume are generally more accurate than other approaches (*e.g.*, engineering estimates) to estimating flare gas volume.

In the absence of measured waste gas flow rate data, engineering estimates can be used. Section 6 presents methodologies for quantifying emissions from vented sources that may be applicable for determining the waste gas flow rate from sources routed to a flare, such as acid gas removal units and storage tanks.

For quantifying GHG emissions from continuous associated gas flaring when the gas flow rate is unknown, an approach based on the gas-to-oil (GOR) ratio can be used (refer to Section 6). In this case, the flare gas volume can be estimated using the amount of oil produced and the GOR of the hydrocarbon production as shown in Equation 6.3-2.

5.1.1.2 Flared Gas Consumption

In addition to the gas flare volume, a measurement or estimate of the composition of the flared gas stream is also needed to quantify CO_2 and CH_4 emissions. It should be noted that the gas composition of the waste stream being flared, and that of the purge and pilot gas, are typically different (e.g., fuel gas used for purge and pilot).

If available, actual composition data is preferred. However, sampling of waste gas routed to a flare system presents safety challenges and therefore is often estimated rather than sampled. Mass balance data (e.g., design compositions from Process Flow Diagrams) can be used to approximate the composition of a flared stream in the absence of measured composition.

Table 5-1 provides "generic" upstream gas compositions for use only if measured data are unavailable. Keep in mind that flare gas compositions can vary significantly, and the compositions provided in Table 5-1 are not meant to be representative of industry averages or typical values.

Table 5-1. "Generic" Upstream Gas Composition

	Raw or Produced Gas Composition [a]	Gas Processing Plant Gas Composition [b]
Gas Component	Volume (or mole) %	Volume (or mole) %
CH_4	80	91.9
C_2H_6	15	6.84[c]
C_3H_8	5	
N_2	-	0.68
CO_2	-	0.58

Footnotes and Sources:

[a] CAPP. *Calculating Greenhouse Gas Emissions*, Guide, 2003-003, Section 1.7.3, April 2003. More detailed speciation profiles can be found in *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulfide (H_2S) Emissions by the Upstream Oil and Gas Industry, Volume 3: Methodology for Greenhouse Gases*. (CAPP, 2004)

[b] IPCC. *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, Volume 2, Chapter 4 (Fugitive Emissions), Table 4.2.4, 2006 Revised November 2008.

[c] The molecular weight of non-methane hydrocarbons is unspecified.

5.1.1.3 Flare Combustion and Destruction Efficiency

Flare combustion efficiency is a measure of the conversion of hydrocarbons to CO_2, expressed as percentage of carbon in the flare feed gas that is completely oxidized to CO_2. Flare destruction efficiency is the percentage of a specific compound in the flare feed gas that is converted to a different compound; in particular methane conversion to CO_2. Destruction efficiency is higher than overall combustion efficiency, with a general estimate that a combustion efficiency of 96.5% is equivalent to a destruction efficiency of 98% (U.S. EPA, 2015). Although the methane destruction efficiency can be higher than the overall flare combustion efficiency, in the absence of data it is conservative to assume the same default value for both combustion and destruction efficiency.

Combustion efficiency, and therefore flare performance, is highly variable, primarily dependent on the flame stability. The flame stability, in turn, depends on the gas exit velocity, burner tube diameter (tip size), heat content, and wind conditions (Johnson et al., 2002). If a crosswind is moderate and energy content of the gas is high, combustion efficiencies in the range of 98-99.5% can be obtained. In an uncontrolled environment, such as an open pipe or open pit without a burner tip, flaring efficiency is reduced significantly. In such a case, the UNFCCC suggests a default value of 50% for combustion efficiency, but the underlying basis for this recommendation is unclear (ICCT, 2014).

Unless regulatory requirements dictate otherwise, general industry practice relies on the widely accepted AP-42 document, which states: "properly operated flares achieve at least 98 percent combustion efficiency" (U.S. EPA, AP-42 Section 13.5.2, September 1991, Reformatted January 1995, Section Revised February 2018), where 98% combustion efficiency is consistent with the performance of other control devices. Early studies to more accurately characterize emissions from oil and gas industry flares indicate a minimum of 98% combustion efficiency, with much higher efficiencies (≥ 99.5%) measured in most situations, and very little, if any, detectable CH_4.[3] (Ozumba, 2000; Strosher, 1996; IFC, 2003). In 2018, the US EPA developed an emissions factor for enclosed ground flares at natural gas production sites. The study determined that the destruction efficiency averaged over 40 field tests was 99.28%. The work further evaluated manufacturer's certification testing in controlled circumstances which found an average destruction efficiency of 99.993% (99.989% at low load[4] and 99.995% at normal to high load) (U. S. EPA, 2018).

For flares in the downstream segment, the US EPA reviewed emissions test data submitted by refineries for the 2011 Petroleum Refinery Information Collection Request. Emissions testing reports were collected for flares used to control catalytic reforming units (CRUs), fluid catalytic cracking units (FCCUs), sulfur recovery units (SRUs), and hydrogen plants, along with several other emissions sources. This work found the average combustion efficiency was 98.3% and the average destruction efficiency was 98.90%. Furthermore, it was observed that utilizing reported total hydrocarbon (THC) data would not be representative of the CH_4 emissions as the exhaust gas includes significant portions of C2-C5+ hydrocarbons (U. S. EPA, 2016).

Table 5-2 summarizes the combustion and destruction efficiencies from each of the previously mentioned studies.

Table 5-2. Summary of Flare Efficiency Data (new)

Source	Combustion Efficiency	Destruction Efficiency
EPA, AP-42 Section 13.5.2, 2018 [a]	98%	-
U. S. EPA, 2018 [a]	-	99.28%.
U. S. EPA, 2016 [b]	98.3%	98.90%.
Ozumba, 2000 [c]; Strosher, 1996 [d]	> 98% (many with much higher efficiencies ~ 99.5%)	-

Footnotes and Sources:

[a] U.S. Environmental Protection Agency. Review and Analysis of Emissions Test Reports for Purposes of Reviewing the Natural Gas Production Flares Volatile Organic Compounds Emissions Factor Under Clean Air Act Section 130U, February 2018

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[3] Note that the Strosher flare study reports combustion efficiencies of less than 98% for tests conducted on two production flares without knockout drums.

[4] Low load is represented by a unit operating at less than 30 percent of maximum load.

[b] U.S. Environmental Protection Agency, Review of Emissions Test Reports for Emissions Factors Development for Flare and Certain Refinery Operations, December 2016.

[c] Ozumba, C.I., and I.C. Okoro. *Combustion Efficiency Measurements of Flares Operated By An Operating Company*, Shell Petroleum Development Company. Presented at the Society of Petroleum Engineers International Conference on Health, Safety, and the Environment in Oil and Gas Exploration and Production held in Stavanger, Norway, June 26-28, 2000.

[d] Strosher, M. *Investigations of Flare Gas Emissions in Alberta*, Final Report, Alberta Research Council, Environmental Technologies, November 1996. http://www.ercb.ca/docs/documents/reports/StrosherInvestigationOfFlareGasEmissions-1996.pdf, accessed May 1, 2009.

5.1.2 Calculation Approaches for Quantifying Flare Emissions

With the information on data sources provided in Section 5.1.1, it is possible to calculate emissions if test data is not available. The calculation methods for quantifying emissions using that data are presented in Sections 5.1.2.1 and 5.1.2.2 below.

It should be noted that the calculations provided in this chapter are only for gas that is combusted in the flare. If there are flare upsets or other events where gas bypasses the flare or the flare is unlit, then that portion of the gas stream should be treated as a vented source (refer to Section 6).

5.1.2.1 CO_2 Emissions Calculation

CO_2 Emissions Calculation if Flare Outlet Data is Known

If the volume of hydrocarbons at the flare outlet is known, Equation 5-1 can be used to calculate CO_2 emissions:

$$E_{CO_2} = \left(HC \times CF_{HC} \times \frac{FE}{1\text{-}FE} \times \frac{44}{12} \right) + M_{CO_2} \qquad \text{(Equation 5-1)}$$

where

E_{CO_2} = CO_2 mass emission rate;
HC = flare hydrocarbon mass emission rate (exiting from the flare);
CF_{HC} = carbon weight fraction in exiting hydrocarbon;
FE = flare combustion efficiency;
44/12 = C to CO_2 mass conversion factor; and
M_{CO_2} = mass of CO_2 in flared stream based on CO_2 composition of the inlet stream.

CO_2 Emissions Calculation if Flare Inlet Data is Known

If measured outlet hydrocarbon emissions data are unavailable, CO_2 emissions from flares can be calculated as shown in Equation 5-2 using volumetric whole gas flare inlet rates and an estimated 98% combustion efficiency for the conversion of the flare gas carbon to CO_2. This estimated combustion efficiency is consistent with published flare emission factors (E&P Forum, 1994), control device performance, EPA GHGRP Subpart W[5], and results from the more recent flare studies.

$$E_{CO_2} = \text{Volume Flared} \times \frac{1}{\text{Molar Volume Conversion}} \times \text{MW CO}_2 \times \text{Mass Conversion} \times \left[\sum\left(\frac{\text{mole Hydrocarbon}}{\text{mole gas}} \times \frac{\text{A mole C}}{\text{mole Hydrocarbon}} \times \frac{0.98 \text{ mole CO}_2 \text{ formed}}{\text{mole C combusted}}\right) + \frac{\text{B mole CO}_2}{\text{mole gas}}\right] \qquad \text{(Equation 5-2)}$$

where

Molar volume conversion = conversion from molar volume to mass (379.3 scf/lbmole or 23.685 sm^3/kgmole);
MW CO_2 = CO_2 molecular weight = 44;
Mass conversion = tonnes/2204.62 lb or tonne/1000 kg;
A = the number of moles of Carbon for the particular hydrocarbon; and
B = the moles of CO_2 present in the flared gas stream.

The above Equation 5-2 can be simplified and evaluated on a mass basis given the tonnes of hydrocarbons directed to the flare as shown below in Equation 5-3 to calculate CO_2 emissions:

$$E_{CO2} = \left(HC_{in} \text{ x } CF_{HC} \text{ x } FE \text{ x } \frac{44}{12}\right) + M_{CO2} \qquad \text{(Equation 5-3)}$$

where

E_{CO_2} = CO_2 mass emission rate;
HC_{in} = flare hydrocarbon mass inlet rate (to the flare);
CF_{HC} = carbon weight fraction in the inlet hydrocarbon;
FE = flare combustion efficiency;
44/12 = C to CO_2 mass conversion factor; and
M_{CO_2} = mass of CO_2 in flared stream based on CO_2 composition of the inlet stream.

Note that in the above Equations (5-1, 5-2 and 5-3), CO_2 present in the stream to the flare is emitted directly as CO_2. Neither the combustion efficiency nor the conversion of flare gas carbon to CO_2 apply to the CO_2 already contained in the flared stream.

For additional conservatism in the calculation of CO_2 emissions, many practitioners in the industry assume 100% complete combustion (instead of 98%) when converting hydrocarbons to CO_2 and then use the default 98% combustion efficiency to calculate methane emissions. This results in a roughly 2% higher CO_2 emission rate.

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[5] 40 CFR 98.233(n)

CO_2 Emissions Calculation if Flare Data are Continuously Monitored

If the flare has a continuous monitor for flow, higher heating value, or gas composition, or is monitored frequently for these parameters then the equations presented in the EPA GHGRP Subpart Y regulations[6] Code of Federal Regulation (CFR) at 40 CFR § 98.253(b)(1) can be used to calculate CO_2 emissions (equations Y-1a, Y-1b, Y-2 or Y-3). These calculation methods follow the same approaches as outlined above, but are relevant for continuous or semi-continuous monitoring of data.

5.1.2.2 CH_4 Emissions Calculation

For CH_4 emissions from flares, general industry practice assumes 0.5% residual, unburned CH_4 remaining in the flared gas (99.5% destruction efficiency) for well-designed and operated flares, such as in refineries. For production flares, where greater operational variability exists, CH_4 emissions may be based on an assumed value of 2% noncombusted (98% destruction efficiency). These recommendations are supported by published flare emission factors (EIIP Volume II, Table 10.2-1, September 1999) and endorsed by IPCC (IPCC, Volume 2, Chapter 4, 2006).[7] In the natural gas transmission, storage, and distribution sectors, flares are assumed to be similar to production flares (INGAA, Section 2.4, 2005).

The general equation for CH_4 emissions from flares, which is aligned with EPA GHGRP Subpart W reporting[8], is:

$$E_{CH_4} = V \times CH_4 \text{ Mole fraction} \times \% \text{ residual } CH_4 \times \frac{1}{\text{molar volume conversion}} \times MW_{CH_4} \quad \text{(Equation 5-4)}$$

where

E_{CH_4} = CH_4 mass emission rate (lb or kg);
V = volume flared (scf or sm^3);
CH_4 Mole fraction = Mole fraction of CH_4 present in the inlet flared gas
% residual CH_4 = uncombusted fraction of flared stream (default =0.5% or 2%);
Molar volume conversion = conversion from molar volume to mass (379.3 scf/lbmole or 23.685 sm^3/kgmole); and
MW CH_4 = CH_4 molecular weight = 16.

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[6] Code of Federal Regulation (CFR) at 40 CFR § 98.253(b)(1)

[7] Note that the Strosher flare study reports combustion efficiencies of less than 98% for tests conducted on two production flares without knockout drums. (IPCC, 2006, Volume 2, Chapter 4).

[8] 40 CFR 98.233(n)

The above Equation 5-4 can be simplified and evaluated on a mass basis given the mass of methane directed to the flare as shown below in Equation 5-5:

$$E_{CH4} = \left(CH_{4_{in}} \text{ x FE}\right)$$

(Equation 5-5)

where

E_{CH4} = CH_4 mass emission rate;
CH_{4in} = flare methane mass inlet rate (to the flare);
FE = uncombusted fraction of flared stream (default =0.5% or 2%).

5.1.2.3 N_2O Emissions Calculation

Information continues to become more available for N_2O emissions from petroleum industry flares, but these emissions are considered negligible compared to CO_2 emissions from flares. Equation 5-6 provides a simple emission factor approach from the US EPA GHGRP Subpart Y for refineries as documented in the code of federal regulation (CFR) at 40 CFR § 98.253(b)(3).

$$E_{N2O} = \left(E_{CO2} \text{ x } \frac{EmF_{N2O}}{EmF_{CO2}}\right) \qquad \text{(Equation 5-6)}$$

where

E_{N2O} = N_2O mass emission rate;
E_{CO2} = CO_2 mass emission rate;
EmF_{N2O} = Default emission factor kg N_2O/MMBTU (default for fuel gas = 3×10^{-3} and for natural gas = 1×10^{-3});
EmF_{CO2} = Default emission factor kg CO_2/MMBTU (default = 60);

5.1.2.4 Alternate Emissions Calculation

The above flare emission calculations are based on knowing the inlet or outlet flare gas rate. The following emission factors are based on the production volume or throughput for different types of petroleum operations and are provided as an alternative to using the methodology described above. Tables 5-3 and 5-4 provide emission factors from the EPA based on industry reported data (EPA, 2020). The tables contain factors for CH_4, CO_2, and N_2O. Table 5-3 provides factors to be applied to flares in petroleum systems, while Table 5-4 provides factors for flares in natural gas systems.

Table 5-3. Flaring Emission Factors for Petroleum Systems by Segment and Source[a]

Segment/Source	CH_4 Emission Factor	Uncertainty (%)	CO_2 Emission Factor	Uncertainty (%)	N_2O Emission Factor	Uncertainty (%)	Units
Exploration							
Non-completion Well Testing – Flared	384.0	Not Specified	125,682.3	Not Specified	0.2	Not Specified	kg/event
HF Completions: Non-REC with Flaring	1,851.2		347,390.4		1.2		kg/event
HF Completions: REC with Flaring	1,678.2		414,864.5		0.7		kg/event
Production							
Associated Gas Flaring	0.1	Not Specified	23.6	Not Specified	5.2E-05	Not Specified	kg/bbl
220 – Gulf Coast Basin (LA, TX)	0.1		34		6.7E-05		kg/bbl
360 – Anadarko Basin	1.6		317		9.0E-04		kg/bbl
395 – Williston Basin	0.1		36		5.8E-05		kg/bbl
430 – Permian Basin	0.05		16		4.9E-05		kg/bbl
“Other” Basins	0.05		24		2.9E-05		kg/bbl
Large Tanks w/Flares	5,615.5	Not Specified	4,631,050.6	Not Specified	58.3	Not Specified	kg/MMbbl
Small Tanks w/Flares	592.1	Not Specified	261,345.4	Not Specified	0.5	Not Specified	kg/MMbbl
Miscellaneous Production Flaring	0.005	Not Specified	1.3	Not Specified	2.0E-05	Not Specified	kg/bbl
220 – Gulf Coast Basin (LA, TX)	0.004		1.3		2.2E-06		kg/bbl
395 – Wiliston Basin	0.006		3.5		5.4E-06		kg/bbl
430 – Permian Basin	0.01		0.9		4.9E-05		kg/bbl
“Other” Basins	0.002		0.6		9.5E-07		kg/bbl
HF Workovers: Non-REC with Flaring	1,851.2	Not Specified	347,390.4	Not Specified	1.2	Not Specified	kg/event
HF Workovers: REC with Flaring	1,678.2	Not Specified	414,864.5	Not Specified	0.7	Not Specified	kg/event

Segment/Source	CH_4 Emission Factor	Uncertainty (%)	CO_2 Emission Factor	Uncertainty (%)	N_2O Emission Factor	Uncertainty (%)	Units
Offshore Production	-	-	-	-	-	-	-
GOM Federal Waters	0.1	Not Specified	54.7	Not Specified	0.001	Not Specified	kg/MMBtu
GOM State Waters	-		642.2		0.01		kg/Mbbl
Pacific Federal and State Waters	0.7		684.6		0.01		kg/Mbbl
Alaska State Waters	6.4		6,034.6		0.1		kg/Mbbl
Refining							
Flares	1.9	Not Specified	589.0	Not Specified	0.006	Not Specified	kg/Mbbl

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2018*, Table 3.5-3, 3.5-8, 3.5-12, April 12, 2020.

Table 5-4. Flaring Emission Factors for Natural Gas Systems by Segment and Source[a]

Segment/Source	CH_4 Emission Factor	Uncertainty (%)	CO_2 Emission Factor	Uncertainty (%)	N_2O Emission Factor	Uncertainty (%)	Units
Exploration							
Non-completion well testing – flared	8,264.7	Not Specified	1,808.851.2	Not Specified	1.3	Not Specified	kg/event
HF Completions – Non-REC with Flaring	3,004.2	Not Specified	360,024.3	Not Specified	3.9	Not Specified	kg/event
HF Completions – REC with Flaring	1,405.5	Not Specified	243,497.7	Not Specified	0.4	Not Specified	kg/event
Non-HF Completions – flared	1,548.2	Not Specified	157,079.2	Not Specified	22.8	Not Specified	kg/event
Production							
HF Workovers – Non-REC with Flaring	3,004.2	Not Specified	360,024.3	Not Specified	3.9	Not Specified	kg/event
HF Workovers – REC with Flaring	1,405.5	Not Specified	243,497.7	Not Specified	0.4	Not Specified	kg/event
Non-HF Workovers – flared	0.7	Not Specified	252.4	Not Specified	3.0E-04	Not Specified	kg/event
Misc. Onshore Production Flaring	-	-	-	-	-	-	-
220 – Gulf Coast Basin	0.2	Not Specified	48.0	Not Specified	1.1E-04	Not Specified	kg/MMscf
395 – Wiliston Basin	0.07		5.3		8.4E-06		kg/MMscf
430 – Permian Basin	1.00		179.5		2.9E-04		kg/MMscf
Other Basins	0.1		17.7		0.0		kg/MMscf
Large Tanks w/Flares	0.0	Not Specified	6.1	Not Specified	0.0	Not Specified	kg/bbl
Small Tanks w/Flares	0.010	Not Specified	5.2	Not Specified	8.8E-06	Not Specified	kg/bbl
Offshore Production	-	-	-	-	-	-	-
GOM Federal Waters, Flare	0.100	Not Specified	54.7	Not Specified	1.0E-03	Not Specified	kg/MMBtu
GOM State Waters, Flare	0.20		188.7		3.0E-03		kg/MMscf
Alaska State Waters, Flare	0.100		89.9		2.0E-03		kg/MMscf
G&B Stations – Flare Stacks	3,047.2	Not Specified	919,684.0	Not Specified	1.6	Not Specified	kg/flare

Segment/Source	CH_4 Emission Factor	Uncertainty (%)	CO_2 Emission Factor	Uncertainty (%)	N_2O Emission Factor	Uncertainty (%)	Units
Processing							
Plant Grouped Emissions – Flares	39,199.0	Not Specified	10,466,437.5	Not Specified	19.700	Not Specified	kg/plant
Transportation and Storage							
Flaring (Transmission)	326.4	Not Specified	37,637.5	Not Specified	0.05	Not Specified	kg/station
Flaring (Storage)	1,797.50	Not Specified	233,520.0	Not Specified	0.1	Not Specified	kg/station
LNG Stations (flares)	4,577.30	Not Specified	60.0	Not Specified	0	Not Specified	kg/facility
LNG Import Terminals (flares)	32,894.00	Not Specified	2,236,413.0	Not Specified	4.4	Not Specified	kg/terminal
LNG Export Terminals (flares)	314,155.00	Not Specified	68,488,900.0	Not Specified	124.5	Not Specified	kg/terminal

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2018*, Table 3.5-3, 3.5-8, 3.5-12, April 12, 2020.

Simplified emission factors are provided in Tables 5-5 and 5-6 for use when only total throughput data is available (IPCC, 2019[9]). Factors provided in Table 5-5 should be applied to systems designed, operated and maintained to North American/Western European standards; Table 5-6 applies to systems in developing countries and countries with economies in transition. IPCC also provides CO_2 and CH_4 emission factors for the same flare sources.[10] These flare emission factors are based on the volume of production or throughput for different types of petroleum operations.

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[9] No updates to these factors in the 2019 refinement; the emission factors are from IPCC, 2007.

[10] The refinery CH_4 flare emission factor is from Annex 3 of the EPA report, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007* (EPA, 2009).

Table 5-5. GHG Emission Factors for Gas Flares in Developed Countries [a]

Original Units							
Flare Source	**Emission Factors**						
	CO_2	**Uncertainty [b] (%)**	**CH_4**	**Uncertainty [b] (%)**	**N_2O**	**Uncertainty [b] (%)**	**Units**
Flaring - gas production [c]	1.2E-03	±25	7.6E-07	±25	2.1E-08	-10 to +1000	Gg/10^6 m^3 gas production
Flaring - sweet gas processing	1.8E-03	±25	1.2E-06	±25	2.5E-08	-10 to +1000	Gg/10^6 m^3 raw gas feed
Flaring - sour gas processing	3.6E-03	±25	2.4E-06	±25	5.4E-08	-10 to +1000	Gg/10^6 m^3 raw gas feed
Flaring - conventional oil production	4.1E-02	±50	2.5E-05	±50	6.4E-07	-10 to +1000	Gg/10^3 m^3 conventional oil production
Flaring - heavy oil/cold bitumen production	2.2E-02	±75	1.4E-04	±75	4.6E-07	-10 to +1000	Gg/10^3 m^3 heavy oil production
Flaring - thermal oil production	2.7E-02	±75	1.6E-05	±75	2.4E-07	-10 to +1000	Gg/10^3 m^3 thermal bitumen production
Flaring – refining [d, e]	No data	No data	0.189	No data	No data	No data	scf/10^3 bbl refinery feed
Units Converted to tonnes/10^6 scf or tonnes/1000 bbl							
Flare Source	**Emission Factors**						
	CO_2	**Uncertainty [b] (%)**	**CH_4**	**Uncertainty [b] (%)**	**N_2O**	**Uncertainty [b] (%)**	**Units**
Flaring - gas production [c]	3.4E-02	±25	2.2E-05	±25	5.9E-07	-10 to +1000	tonnes/10^6 scf gas production
Flaring - sweet gas processing	5.1E-02	±25	3.4E-05	±25	7.1E-07	-10 to +1000	tonnes/10^6 scf raw gas feed
Flaring - sour gas processing	0.10	±25	6.8E-05	±25	1.5E-06	-10 to +1000	tonnes/10^6 scf raw gas feed
Flaring - conventional oil production	6.5	±50	4.0E-03	±50	1.0E-04	-10 to +1000	tonnes/10^3 bbl conventional oil production
Flaring - heavy oil/cold bitumen production	3.5	±75	2.2E-02	±75	7.3E-05	-10 to +1000	tonnes/10^3 bbl heavy oil production
Flaring - thermal oil production	4.3	±75	2.5E-03	±75	3.8E-05	-10 to +1000	tonnes/10^3 bbl thermal bitumen production
Flaring - refining [d, e]	No data	No data	3.63E-06	No data	No data	No data	tonnes/10^3 bbl refinery feed

Table 5-5. GHG Emission Factors for Gas Flares in Developed Countries [a], continued

Units Converted to tonnes/10^6 m^3 or tonnes/1000 m^3

Flare Source	**Emission Factors**						
	CO_2	**Uncertainty [b] (%)**	**CH_4**	**Uncertainty [b] (%)**	**N_2O**	**Uncertainty [b] (%)**	**Units**
Flaring - gas production [c]	1.2	±25	7.6E-04	±25	2.1E-05	-10 to +1000	tonnes/10^6 m^3 gas production
Flaring - sweet gas processing	1.8	±25	1.2E-03	±25	2.5E-05	-10 to +1000	tonnes/$10^6 m^3$ raw gas feed
Flaring - sour gas processing	3.6	±25	2.4E-03	±25	5.4E-05	-10 to +1000	tonnes/$10^6 m^3$ raw gas feed
Flaring - conventional oil production	41.0	±50	2.5E-02	±50	6.4E-04	-10 to +1000	tonnes/10^3 m^3 conventional oil production
Flaring - heavy oil/cold bitumen production	22.0	±75	1.4E-01	±75	4.6E-04	-10 to +1000	tonnes/10^3 m^3 heavy oil production
Flaring - thermal oil production	27.0	±75	1.6E-02	±75	2.4E-04	-10 to +1000	tonnes/10^3 m^3 thermal bitumen production
Flaring – refining [d, e]	No data	No data	2.28E-05	No data	No data	No data	tonnes/10^3 m^3 refinery feed

Footnotes and Sources:

[a] IPCC, *2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2, Chapter 4 (Fugitive Emissions)*, Table 4.2.4, 2006 Revised November 2008.

[b] Uncertainty based on a 95% confidence interval (IPCC, Volume 2, Chapter 4, Section 4.2.2.7.2, 2006 Revised November 2008).

[c] IPCC reports that flared volumes should be used to estimate flare emissions instead of the above emission factors when such data are available. IPCC reports that flared volume based emission factors are 0.012, 2.0 and 0.000023 Gg/10^6 m^3 of gas flared for CH_4, CO_2, and N_2O, respectively, based on a flaring efficiency of 98% and a typical gas analysis at a gas processing plant (91.9% CH_4, 0.58% CO_2, 0.68% N_2 and 6.84% non-CH_4 hydrocarbons, by volume).

[d] U.S. Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007*, Table A-127, April 15, 2009.

[e] CH_4 emission factors converted from scf or m^3 are based on 60°F and 14.7 psia.

Table 5-6. GHG Emission Factors for Gas Flares in Developing Countries and Countries with Economies in Transition[a]

Original Units

Flare Source	Emission Factors						
	CO_2	Uncertainty [b] (%)	CH_4	Uncertainty [b] (%)	N_2O	Uncertainty [b] (%)	Units
Flaring - gas production [c]	1.2E-03 – 1.6E-03	±75	7.6E-07 – 1.0E-06	±75	2.1E-08 – 2.9E-08	-10 to +1000	Gg/10^6 m^3 gas production
Flaring - sweet gas processing	1.8E-03 – 2.5E-03	±75	1.2E-06 – 1.6E-06	±75	2.5E-08 – 3.4E-08	-10 to +1000	Gg/10^6 m^3 raw gas feed
Flaring - sour gas processing	3.6E-03 – 4.9E-03	±75	2.4E-06 – 3.3E-06	±75	5.4E-08 – 7.4E-08	-10 to +1000	Gg/10^6 m^3 raw gas feed
Flaring - conventional oil production	4.1E-02 – 5.6E-02	±75	2.5E-05 – 3.4E-05	±75	6.4E-07 – 8.8E-07	-10 to +1000	Gg/10^3 m^3 conventional oil production
Flaring - heavy oil/cold bitumen production	2.2E-02 – 3.0E-02	-67 to +150	1.4E-04 – 1.9E-04	-67 to +150	4.6E-07 – 6.3E-07	-10 to +1000	Gg/10^3 m^3 heavy oil production
Flaring - thermal oil production	2.7E-02 – 3.7E-02	-67 to +150	1.6E-05 – 2.2E-05	-67 to +150	2.4E-07 – 3.3E-07	-10 to +1000	Gg/10^3 m^3 thermal bitumen production

Units Converted to tonnes/10^6 scf or tonnes/1000 bbl

Flare Source	Emission Factors						
	CO_2	Uncertainty [b] (%)	CH_4	Uncertainty [b] (%)	N_2O	Uncertainty [b] (%)	Units
Flaring - gas production [c]	3.4E-02 – 4.5E-02	±75	2.2E-05 – 2.8E-05	±75	5.9E-07 – 8.2E-07	-10 to +1000	tonnes/10^6 scf gas production
Flaring - sweet gas processing	5.1E-02 – 7.1E-02	±75	3.4E-05 – 4.5E-05	±75	7.1E-07 – 9.6E-07	-10 to +1000	tonnes/10^6 scf raw gas feed
Flaring - sour gas processing	0.10 – 0.14	±75	6.8E-05 – 9.3E-05	±75	1.5E-06 – 2.1E-06	-10 to +1000	tonnes/10^6 scf raw gas feed
Flaring - conventional oil production	6.5 – 8.9	±75	4.0E-03 – 5.4E-03	±75	1.0E-04 – 1.4E-04	-10 to +1000	tonnes/10^3 bbl conventional oil production
Flaring - heavy oil/cold bitumen production	3.5 – 4.8	-67 to +150	2.2E-02 – 3.0E-02	-67 to +150	7.3E-05 – 1.0E-04	-10 to +1000	tonnes/10^3 bbl heavy oil production
Flaring - thermal oil production	4.3 – 5.9	-67 to +150	2.5E-03 – 3.5E-03	-67 to +150	3.8E-05 – 5.2E-05	-10 to +1000	tonnes/10^3 bbl thermal bitumen production

Table 5-6. GHG Emission Factors for Gas Flares in Developing Countries and Countries with Economies in Transition[a], continued

Units Converted to tonnes/10^6 m^3 or tonnes/1000 m^3							
Flare Source	**Emission Factors**						
	CO_2	**Uncertainty [b] (%)**	**CH_4**	**Uncertainty [b] (%)**	**N_2O**	**Uncertainty [b] (%)**	**Units**
Flaring - gas production [c]	1.2 – 1.6	±75	7.6E-04 – 1.0E-03	±75	2.1E-05 – 2.9E-05	-10 to +1000	tonnes/10^6 m^3 gas production
Flaring - sweet gas processing	1.8 – 2.5	±75	1.2E-03 – 1.6E-03	±75	2.5E-05 – 3.4E-05	-10 to +1000	tonnes/$10^6 m^3$ raw gas feed
Flaring - sour gas processing	3.6 – 4.9	±75	2.4E-03 – 3.3E-03	±75	5.4E-05 – 7.4E-05	-10 to +1000	tonnes/$10^6 m^3$ raw gas feed
Flaring - conventional oil production	41.0 – 56.0	±75	2.5E-02 – 3.4E-02	±75	6.4E-04 – 8.8E-04	-10 to +1000	tonnes/10^3 m^3 conventional oil production
Flaring - heavy oil/cold bitumen production	22.0 – 30.0	-67 to +150	1.4E-01 – 1.9E-01	-67 to +150	4.6E-04 – 6.3E-04	-10 to +1000	tonnes/10^3 m^3 heavy oil production
Flaring - thermal oil production	27.0 – 37.0	-67 to +150	1.6E-02 – 2.2E-02	-67 to +150	2.4E-04 – 3.3E-04	-10 to +1000	tonnes/10^3 m^3 thermal bitumen production

Footnotes and Sources:

[a] IPCC, *2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2, Chapter 4 (Fugitive Emissions)*, Table 4.2.5, 2006 Revised November 2008.

[ba] Uncertainty based on a 95% confidence interval (IPCC, Volume 2, Chapter 4, Section 4.2.2.7.2, 2006 Revised November 2008).

[c]*4*IPCC reports that flared volumes should be used to estimate flare emissions instead of the above emission factors when such data are available. IPCC reports that flared volume based emission factors are 0.012, 2.0 and 0.000023 Gg/10^6 m^3 of gas flared for CH_4, CO_2, and N_2O, respectively, based on a flaring efficiency of 98% and a typical gas analysis at a gas processing plant (91.9% CH_4, 0.58% CO_2, 0.68% N_2 and 6.84% non-CH_4 hydrocarbons, by volume).

Exhibit 5.1 demonstrates emission calculations for gas flares when the volume to the flare is known.

EXHIBIT 5.1: Sample Calculation for Combustion Emissions from a Gas Flare – Known Flared Volume

INPUT DATA:
A production facility in a developed country produces 3 million scf/day of natural gas. In a given year, 20 million scf of field gas are flared at the facility. The flare gas composition is: 12 mole% CO_2, 2.1 mole% N_2, 80 mole% CH_4, 4.2 mole% C_2H_6, 1.3 mole% C_3H_8, and 0.4 mole% C_4H_{10}. The volume of the pilot stream combusted is included in the volume of the field gas flared.

ASSUMPTIONS:
Since test results or vendor data are not available, emissions will be calculated based on the alternative approaches of 98% combustion efficiency for CO_2 emissions and 2% uncombusted CH_4.

CALCULATION METHODOLOGY:
Methane emissions are based on the assumption that 2% of the CH_4 in the flare gas is released uncombusted.

$$E_{CH_4}\text{:}\frac{20\times10^6\ \text{scf gas}}{\text{yr}}\times\frac{0.80\ \text{scf CH}_4}{\text{scf gas}}\times\frac{0.02\ \text{scf noncombusted CH}_4}{\text{scf CH}_4\text{total}}$$

$$\times\frac{\text{lbmole CH}_4}{379.3\ \text{scf CH}_4}\times\frac{16\ \text{lb CH}_4}{\text{lbmole CH}_4}\times\frac{\text{tonne}}{2204.62\ \text{lb}}$$

$$E_{CH_4} = \underline{6.1\ \text{tonnes CH}_4/\text{yr}}$$

Carbon dioxide emissions are based on the facility gas composition and the generally accepted 98% combustion efficiency to convert from flare gas carbon to CO_2.

EXHIBIT 5.1: Sample Calculation for Combustion Emissions from a Gas Flare, continued

$$E_{CO_2}: \frac{20\times10^6 \text{ scf gas}}{\text{yr}} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \times$$

$$\left[\left(\begin{array}{l} \dfrac{0.80 \text{ lbmole CH}_4}{\text{lbmole gas}} \times \dfrac{1 \text{ lbmole C}}{\text{lbmole CH}_4} \\ + \dfrac{0.042 \text{ lbmole C}_2\text{H}_6}{\text{lbmole gas}} \times \dfrac{2 \text{ lbmole C}}{\text{lbmole C}_2\text{H}_6} \\ + \dfrac{0.013 \text{ lbmole C}_3\text{H}_8}{\text{lbmole gas}} \times \dfrac{3 \text{ lbmole C}}{\text{lbmole C}_3\text{H}_8} \\ + \dfrac{0.004 \text{ lbmole C}_4\text{H}_{10}}{\text{lbmole gas}} \times \dfrac{4 \text{ lbmole C}}{\text{lbmole C}_4\text{H}_{10}} \end{array}\right) \times \frac{0.98 \text{ lbmole CO}_2 \text{ formed}}{\text{lbmole C combusted}} + \frac{0.12 \text{ lbmole CO}_2}{\text{lbmole gas}}\right] \times \frac{44 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$E_{CO_2} = \underline{1{,}095 \text{ tonnes CO}_2\text{/yr}}$$

N_2O emissions are calculated using the emission factor for “Flaring - gas production” in Table 5-5. Note that these emission factors are based on the total volume of gas produced at the facility. For comparison purposes, CO_2 and CH_4 emissions are also estimated using the published emission factors for “Flaring - gas production.”

$$E_{N_2O}: \frac{3\times10^6 \text{ scf gas}}{\text{day}} \times \frac{365 \text{ days}}{\text{yr}} \times \frac{5.9\times10^{-7} \text{ tonnes N}_2\text{O}}{10^6 \text{ scf gas}} = \underline{6.46\times10^{-4} \text{ tonnes N}_2\text{O/yr}}$$

$$E_{CO_2}: \frac{3\times10^6 \text{ scf gas}}{\text{day}} \times \frac{365 \text{ days}}{\text{yr}} \times \frac{3.4\times10^{-2} \text{ tonnes CO}_2}{10^6 \text{ scf gas}} = \underline{37.23 \text{ tonnes CO}_2\text{/yr}}$$

$$E_{CH_4}: \frac{3\times10^6 \text{ scf gas}}{\text{day}} \times \frac{365 \text{ days}}{\text{yr}} \times \frac{2.2\times10^{-5} \text{ tonnes CH}_4}{10^6 \text{ scf gas}} = \underline{0.024 \text{ tonnes CH}_4\text{/yr}}$$

Exhibit 5.2 demonstrates an example calculation for GHG emissions from a gas flare when the VOC emissions from the flare are known, but the flow rate to the flare is not known.

EXHIBIT 5.2: Sample Calculation for Gas Flare Combustion Emissions – Known Flare Emissions

INPUT DATA:
A gas flare is estimated to emit 2.21 tons of VOC during the reporting year. The average analysis of the gas stream to the flare is shown below. The flare destruction efficiency is 98%. Calculate the CO_2, CH_4, and N_2O emissions from this source.

Compound	Weight %
Methane	2.73
Ethane	0.85
Propane	1.35
Butanes	0.99
Pentanes	0.83
C6+	2.16
Carbon Dioxide	90.43
Inerts (as N_2)	0.66

VOC Weight % = 5.33
Hydrocarbon Weight % = 8.91

1. *Calculate CO_2 emissions.* The first step in calculating the CO_2 emissions is calculating the carbon content of the hydrocarbon mixture, as shown in Equation 4-10. The fuel sample must first be normalized to exclude CO_2 and inerts. Then, the carbon contents of the individual constituents must be calculated using Equation 4-9. This is shown below for ethane (C_2H_6).

$$\text{Wt\%C}_{C_2H_6} = \frac{12 \text{ lb C}}{\text{lbmole C}} \times \frac{2 \text{ lbmoles C}}{\text{lbmole } C_2H_6} \times \frac{\text{lbmole } C_2H_6}{30.07 \text{ lb } C_2H_6} = \underline{0.80 \text{ lb C/lb } C_2H_6}$$

$$\text{Wt\%C}_{C_2H_6} = 80\% \text{ C}$$

Repeating this calculation for the rest of the sample results in the following:

	Adjusted Wt%	**Carbon Content (Wt% C)**
Methane	30.64	74.8%
Ethane	9.54	79.8%
Propane	15.15	81.6%
Butanes	11.11	82.6%
Pentanes	9.32	83.2%
C6+	24.24	83.5%
Carbon Dioxide	0	27.3%
Inerts (as N_2)	0	0.0%
Fuel Mixture	**100**	**80.08%**

EXHIBIT 5.2: Sample Calculation for Gas Flare Combustion Emissions – Known Flare Emissions, continued

The carbon content of the fuel mixture is then calculated using Equation 4-10.

$$\text{Wt\%C}_{\text{Mixture}} = \frac{1}{100} \times \left[\begin{array}{l} (30.64\times74.8)+(9.54\times79.8)+(15.15\times81.6)+(11.11\times82.6) \\ +(9.32\times83.2)+(24.24\times83.5)+(0\times27.3)+(0\times0) \end{array} \right]$$

$\text{Wt\%C}_{\text{Mixture}}$ = 80.08 Wt%C (alternately presented as 0.8008 lb C/lb fuel)

Because the estimated VOC emission rate from the flare is known, Equation 4-15 will be used to calculate CO_2 emissions from the flare. To use Equation 4-15, the VOC emissions must be converted to total hydrocarbon emissions, and the mass of the carbon dioxide released must be calculated:

$$E_{HC} = \frac{2.21\text{ tons VOC}}{\text{yr}} \times \frac{100\text{ lb gas}}{5.33\text{ lbVOC}} \times \frac{8.91\text{ lb hydrocarbon}}{100\text{ lb gas}}$$

E_{HC} = 3.69 tons hydrocarbon from the flare/yr

$$M_{CO_2} = \frac{2.21\text{ tons VOC}}{\text{yr}} \times \frac{100\text{ lb gas}}{5.33\text{ lbVOC}} \times \frac{90.43\text{ lb }CO_2}{100\text{ lb gas}}$$

M_{CO_2} = 37.50 tons CO_2/yr

Equation 5-1 is then used to calculate CO_2 emissions.

$$E_{CO_2} = \left[\begin{array}{l} \left(\frac{3.69\text{ tons hydrocarbon}}{\text{yr}} \times \frac{0.8008\text{ ton C}}{\text{ton hydrocarbon}} \times \frac{0.98}{1\text{ - }0.98} \times \frac{44\text{ ton }CO_2}{12\text{ ton C}} \right) \\ + \frac{37.50\text{ tons }CO_2}{\text{yr}} \end{array} \right] \times \frac{\text{tonne}}{1.10231\text{ ton}}$$

$\underline{E_{CO_2} = 515.7\text{ tonnes }CO_2\text{/yr}}$

EXHIBIT 5.2: Sample Calculation for Gas Flare Combustion Emissions – Known Flare Emissions, continued

2. *Calculate CH_4 emissions.* Methane emissions are calculated using Equation 5-5, which is modified to reflect the fact that the mass flared is known:

$$E_{CH_4} = (\text{Mass Flared}) \times (CH_4 \text{ Weight fraction}) \times (\% \text{ residual } CH_4)$$

$$E_{CH_4} = \frac{3.69 \text{ tons hydrocarbon}}{\text{yr}} \times \frac{1}{1 - 0.98} \times \frac{100 \text{ tons gas}}{8.91 \text{ tons hydrocarbon}} \times \frac{2.73 \text{ tons } CH_4}{100 \text{ tons gas}} \times (1 - 0.98) \times \frac{\text{tonne}}{1.10231 \text{ ton}}$$

$$\underline{E_{CH_4} = 1.03 \text{ tonnes } CH_4/\text{yr}}$$

3. *Calculate N_2O emissions.* Nitrous oxide emissions are calculated using the natural gas fuel based emission factor from Table 4-6. The use of the emission factor requires the quantity of fuel combusted on a heat basis, which requires the higher heating value of the fuel. The fuel heating value is calculated using Equation 3-11. Note that to use Equation 3-11, the adjusted fuel speciation data is converted from weight % to mole % (as shown in Equation 3-7), using the molecular weight of the mixture on a hydrocarbon basis.

The molecular weight of the mixture is calculated using Equation 3-9.

$$MW_{\text{Mixture}} = 100 \div \begin{bmatrix} (30.64 \div 16.04) + (9.54 \div 30.07) + (15.15 \div 44.10) + (11.11 \div 58.12) \\ + (9.32 \div 72.15) + (24.24 \div 86.18) + (0 \div 44.01) + (0 \div 28.01) \end{bmatrix}$$

$$MW_{\text{Mixture}} = 31.52 \text{ lb/lbmole}$$

The conversion from weight % to mole % is shown below for C_2H_6.

$$\text{Mole\%}_{C_2H_6} = \frac{\frac{9.54 \text{ lb } C_2H_6}{100 \text{ lb gas}} \times \frac{31.52 \text{ lb gas}}{\text{lbmole gas}}}{\frac{30.07 \text{ lb } C_2H_6}{\text{lbmole } C_2H_6}} = \underline{10.00 \text{ lbmole } C_2H_6/100 \text{ lbmole gas}}$$

$$\text{Mole\%}_{C_2H_6} = 10.00\%$$

Repeating this calculation for the rest of the sample results in the following:

EXHIBIT 5.2: Sample Calculation for Gas Flare Combustion Emissions – Known Flare Emissions, continued

	Molecular Weight	Adjusted Mol%	Heating Value (Btu/scf)
Methane	16.04	60.21	1009.7
Ethane	30.07	10.00	1768.8
Propane	44.10	10.83	2517.5
Butanes	58.12	6.03	3262.1
Pentanes	72.15	4.07	4009.6
C6+	86.18	8.87	4756.2
Carbon Dioxide	44.01	0.00	0
Inerts (as N_2)	28.01	0.00	0
Fuel Mixture	**31.52**	**100**	**1838.9**

The heating value of the mixture is calculated below.

$$\mathrm{HHV}_{\mathrm{Mixture}} = \left[\begin{array}{l} \left(\frac{60.21}{100}\times 1009.7\right)+\left(\frac{10.00}{100}\times 1768.8\right)+\left(\frac{10.83}{100}\times 2517.5\right)+\left(\frac{6.03}{100}\times 3262.1\right) \\ +\left(\frac{4.07}{100}\times 4009.6\right)+\left(\frac{8.87}{100}\times 4756.2\right)+(0\times 0)+(0\times 0) \end{array}\right]$$

$$\mathrm{HHV}_{\mathrm{Mixture}} = 1838.9\ \mathrm{Btu/scf}$$

$$E_{N_2O} = (\text{Volume Hydrocarbon Flared})\times(\text{Heating Value})\times(N_2O\text{ emission factor})$$

$$E_{N_2O} = \frac{3.69\text{ tons hydrocarbon}}{\text{yr}}\times\frac{2{,}000\text{ lb}}{\text{ton}}\times\frac{\text{lbmole hydrocarbon}}{31.52\text{ lb hydrocarbon}}\times\frac{379.3\text{ scf}}{\text{lbmole}}$$
$$\times\frac{1}{1-0.98}\times\frac{1838.9\text{ Btu}}{\text{scf}}\times\frac{9.50\times 10^{-8}\text{ tonnes }N_2O}{10^{6}\text{ Btu}}$$

$$\underline{E_{N_2O} = 7.76\times 10^{-4}\text{ tonnes }N_2O/\text{yr}}$$

5.2 Incinerators, Oxidizers, and Vapor Combustion Units

Incinerators, thermal and catalytic oxidizers, and vapor combustion units (VCUs, which include a broad range of control devices including enclosed combustion devices) may be used as control devices or to combust waste fuels. For gaseous waste streams, the terms ‘incinerator’ and ‘oxidizer’ are often used interchangeably and generally refer to the use of themal or catalytic oxidizers. The main types of thermal oxidizers are direct fire, catalytic, recuperative, and regenerative. Since the inlet waste gas temperature is generally much lower than that required for complete combustion, auxiliary fuel is added to raise the waste gas temperature (EPA Cost Control Manual, 2019).

Carbon dioxide emissions from hydrocarbons in the combusted stream can be estimated by mass balance using an assumed conversion of carbon in the fuel gas to CO_2 or based on the control efficiency of the unit. Equations 5-2 and 5-3 for quantifying CO_2 emissions from flares can be used for incinerators, oxidizers and VCUs. However the combustion efficiency is typically higher than elevated flares, with 99% and above typical depending on unit design.

In the absence of data on gas composition, the external combustion emission factors given by fuel usage (described in Section 4.4) can be used for estimating CO_2 emissions. Carbon dioxide present in the stream is emitted directly as CO_2.

Methane emissions from these sources can be estimated from a mass balance by assuming a certain CH_4 destruction efficiency, similar to flares using Equation 5-4. Nitrous oxide emissions can be estimated by applying an emission factor from Table 4-9, assuming the control device is similar to a heater.

The following example shows the approach that can be used to estimate CO_2, CH_4, and N_2O emissions from a thermal oxidizer.

EXHIBIT 5.3: Sample Calculation for Combustion Emissions – Thermal Oxidizer

INPUT DATA:
A thermal oxidizer is used to control emissions from crude oil loading at a terminal. Previous stack test data have demonstrated that the oxidizer achieves at least 99% destruction of the oil vapors. The thermal oxidizer does not require supplemental fuel to operate properly.

The following is known about the loading operations based on process knowledge and/or engineering judgment:

Loading throughput: 4,122,487 bbl crude
Loading loss: 1.23 lb VOC/1000 gal

Compound	Molecular Weight	Mole %	Wt %	lb C/lb	Contribution to Mixture C Content
Benzene (C_6H_6)	78.11	1.28	2.12	0.92	1.96
Butane (C_4H_{10})	58.12	59.80	73.58	0.83	60.77
Cyclohexane (C_6H_{12})	84.16	1.04	1.86	0.86	1.59
Ethylbenzene (C_8H_{10})	106.16	0.07	0.15	0.79	0.12
Hexane (C_6H_{14})	86.17	3.77	6.88	0.84	5.75
Toluene (C_7H_8)	92.13	0.15	0.29	0.91	0.27
Xylene (C_8H_{10})	106.16	0.05	0.11	0.90	0.10
Methane (CH_4)	16.04	22.08	7.50	0.75	5.61
Ethane (C_2H_6)	30.07	11.78	7.50	0.80	5.99
	47.23	100	100		82.15

EXHIBIT 5.3: Sample Calculation for Combustion Emissions – Thermal Oxidizer, continued

Calculate the CO_2 and CH_4 emissions. (Note, there are no published N_2O emission factors for the combustion of crude vapors.)

CALCULATION METHODOLOGY:

1. *Calculate CO_2 emissions.* The first step in estimating the oxidizer CO_2 emissions is to calculate the TOC flow rate to the incinerator. TOC emissions are calculated from VOC loading loss by assuming that VOC comprises 85% of TOC in crude oil (AP-42, Section 5.2, September 2020).

$$E_{TOC} = \frac{4{,}122{,}487\text{ bbl}}{\text{yr}} \times \frac{42\text{ gal}}{\text{bbl}} \times \frac{1.23\text{ lb VOC}}{1000\text{ gal crude}} \times \frac{\text{lb TOC}}{0.85\text{ lb VOC}}$$

$$E_{TOC} = 250{,}550\text{ lb TOC/yr}$$

The second step is to convert TOC flow rate to CO_2 emissions, using the fuel carbon content and oxidizer combustion efficiency.

$$E_{CO_2} = \frac{250{,}550\text{ lb TOC}}{\text{yr}} \times \frac{0.8215\text{ lb C}}{\text{lb TOC}} \times \frac{44\text{ lb CO}_2}{12\text{ lb C}} \times \frac{0.99\text{ lb CO}_2\text{ formed}}{\text{lb CO}_2\text{ combusted}} \times \frac{\text{tonne}}{2204.62\text{ lb}}$$

$$\underline{E_{CO_2} = 338.9\text{ tonnes CO}_2\text{/yr}}$$

2. *Calculate CH_4 emissions.* Methane emissions are calculated by multiplying the uncombusted portion of the oxidizer crude oil feed by the CH_4 content of the crude (wt%), as shown below:

$$E_{CH_4} = \frac{250{,}550\text{ lb TOC}}{\text{yr}} \times \frac{0.075\text{ lb CH}_4}{\text{lb TOC}} \times \frac{(1\text{-}0.99)\text{ lb CH}_4\text{ emitted}}{\text{lb CH}_4\text{ combusted}} \times \frac{\text{tonne}}{2204.62\text{ lb}}$$

$$\underline{E_{CH_4} = 0.085\text{ tonnes CH}_4\text{/yr}}$$

5.3 References

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Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Natural Gas and Oil Industry

Section 6 - Process and Vented Emission Estimation Methods

November 2021

TABLE OF CONTENTS

List of Tables

List of Figures

6.0 PROCESS AND VENTED EMISSIONS ESTIMATION METHODS

6.4 Process and Vented Emission Estimated Methods

Vented emissions are releases to the atmosphere as a result of the process or equipment design or operational practices. A number of vented emission sources are associated with oil and gas industry operations. Vented emissions may come from a variety of non-fired stacks and vents (combustion emissions are covered in Section 4). These emission sources tend to be very specific to the type of operation; therefore, this section is organized by segments of the oil and gas industry. Table 6-1 illustrates the range of available options for estimating vented GHG emissions and associated considerations. To optimize cost effectiveness and reporting efficiency, facility operators may choose to use a mix of estimation approaches. It is important to document the estimation method used for each vent source.

Table 6-1. Emission Estimation Approaches – GHG and Source-Specific Considerations for Vented Sources

Types of Approaches	CH_4 Non-combustion Emissions	CO_2 Emissions	PFC and HFC Emissions
Published emission factors	• Based on "average" equipment and emission source characteristics	• Limited emission factors specific to non-combustion CO_2 emissions. • May be scaled from CH_4 emission factors	• Simplified estimation based on "average" equipment and emission source characteristics are consistent with low contribution to overall emissions
Engineering manufacturer emission factors	• Highly reliable for specific emission sources • Requires tracking number of equipment by type and utilization	• CO_2 emissions may be scaled from other non-combustion emission factors based on gas composition	
Engineering calculations	• Highly reliable for specific emission sources • May require detailed input data	• Highly reliable for many emission sources • May require detailed input data	• Material balance methods provide good reliability. • Requires data tracking
Monitoring over a range of conditions and deriving emission factors	• Highly reliable for specific emission sources • Generally not practical given the substantial number of emission sources	• Generally not practical given the low contribution to overall emissions	• Generally not practical given the low contribution to overall emissions
Periodic or continuous monitoring of emissions or parameters for calculating emissions	• Highly reliable for specific emission sources • Generally not practical given the substantial number of emission sources	• Not practical given the number of emission sources and the low contribution to overall emissions	• Not practical given the number of emission sources and the low contribution to overall emissions

6.2 Oil and Natural Gas Exploration

Vented and process emissions from the oil and natural gas exploration segment include venting of gas containing methane (CH_4), and possibly carbon dioxide (CO_2), from well drilling[1], well testing, and well completion activities.

6.2.1 Well Drilling

Vented emissions during well drilling activities occur due to gas released from the drilling fluid. Drilling fluid (otherwise known as drilling mud) is used for many important purposes, including lubricating and cooling the drill bit, carrying cuttings away from the drill bit, and maintaining desired pressure within the well. During these operations, gas from the well bore may become entrained in the mud. During the drilling process, the drilling mud is recirculated and degassed once outside the wellbore to remove the entrained gas. During mud degassing, gases entrained in the mud are separated from the mud and vented directly to the atmosphere. This venting results primarily in emissions of CH_4 contained in the gas, with some possible CO_2 emissions.

Site-specific CH_4 (and CO_2 if present) concentration data should be used to estimate these emissions (e.g. mud-logger services with gas detection system). However, in the absence of site-specific data, use of simplified emission factors presented in Table 6-2 or Table 6-3 can be used.

Table 6-2 provides mud degassing total hydrocarbon (THC) vented emission factors on a drilling day basis. The base THC factors are taken from U.S. Department of the Interior, Minerals Management Service guidance for offshore wells (Wilson et al., 2007). The CH_4 and whole gas factors are derived from the THC factors based on the actual CH_4 concentration from the study. However, the factors can be adjusted using actual site-specific concentrations if they are available and different from the defaults shown in the table. For onshore wells, the emission factors were adjusted based on API member company comments indicating that the borehole size and porosity are lower (by 44 and 40 percent, respectively) for onshore wells compared to offshore (Koblitz, 2020).

Table 6-2. Mud Degassing Vented Methane Emission Factors for Oil and Natural Gas Exploration

Mud Type	**Total Hydrocarbon Emission Factor [a], Original Units (lb THC/drilling day)**	**Methane Emission Factor [b], Converted to Tonnes Basis (tonnes CH_4/drilling day)**	**Whole Gas Emission Factor [c] (scf gas/drilling day)**
Offshore Well Mud Degassing			
Water-based Mud	881.84	0.2605	16,223
Oil-based Mud	198.41	0.0586	3,650
Synthetic Mud	198.41	0.0586	3,650

---

[1] Well drilling activities can occur during exploration (wildcat and appraisal wells) and field development (development wells). The GHG emissions characteristics are typically similar, so they are treated collectively as drilling activities.

Mud Type	Total Hydrocarbon Emission Factor [a], Original Units (lb THC/drilling day)	Methane Emission Factor [b], Converted to Tonnes Basis (tonnes CH_4/drilling day)	Whole Gas Emission Factor [c] (scf gas/drilling day)
Onshore Well Mud Degassing[d]			
Water-based Mud	155.1	0.0458	2,857
Oil-based Mud	34.9	0.0103	642
Synthetic Mud	34.9	0.0103	642

Footnotes and Sources:

[a] 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., https://digital.library.unt.edu/ark:/67531/metadc955168/m2/1/high_res_d/4276.pdf

[b] Based on gas content of 65.13 weight percent CH_4, 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_4, 5.41% C_2H_6, 6.12% C_3H_8, 3.21% C_4H_{10}, and 1.40% C_5H_{12} (Wilson et al. 2007).

[c] The THC mass emission factor is converted to scf at 60°F and 14.7 psia, with average gas molecular weight of 20.6 based on sample gas composition. The CH_4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH_4 content from the default basis (if given). Also, if the facility gas contains significant[2] quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

[d] The emission factors for onshore well mud degassing have been adjusted based on API comments to EPA: *API Comments on EPA's Updates under Consideration for the 2021 GHGI: Mud Degassing and Produced Water Emissions (EPA, 2020b),* October 16, 2020, https://www.epa.gov/sites/production/files/2020-10/documents/ghgi-webinar2020-degassing-comments.pdf. The emission factors were adjusted by the following estimates: a) typical well bore hole size onshore is around 8 in., which is 44% of the bore cross section used in the offshore emission factor derivation based on 12 in. bore hole; and b) porosity for most current onshore wells is 40% of the porosity assumed offshore in the emission factor derivation.

An example calculation is given in Exhibit 6-1 to illustrate the use of the mud degassing emission factors.

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[2] Significance threshold is based on individual site data, and is a function of the volume vented and the concentration of CO_2. Engineering judgement will be required when determining if the stream has quantities of CO_2 that would be deemed significant in the context of the overall GHG emissions inventory for the facility.

EXHIBIT 6-1: Sample Calculation for Mud Degassing Vented Emissions

INPUT DATA:

An oil and gas production facility performed well drilling activities with water-based mud 85 days during the year. The average CH_4 content of the gas is 70 mole %; there is also 9 mole % CO_2 in the gas. Calculate the CH_4 and CO_2 emissions.

CALCULATION METHODOLOGY:

Emissions are calculated by multiplying the number of days of drilling activities by the CH_4 emission factor from Table 6-2. The base mud degassing vented CH_4 emission factor is adjusted from the default basis of 83.85 mole % CH_4 to the site-specific basis of 70 mole % CH_4. Because the gas contains a significant quantity of CO_2, emissions of CO_2 are also estimated using the relative CO_2 and CH_4 contents in the gas.

$$E_{CH_4} = \frac{85\text{ day}}{\text{yr}} \times \frac{0.2605\text{ tonnes }CH_4}{\text{day}} \times \frac{70\text{ mole \% }CH_4}{83.85\text{ mole \% }CH_4}$$

$$\underline{E_{CH_4} = 18.49\text{ tonnes }CH_4/\text{yr}}$$

$$E_{CO_2} = \frac{85\text{ day}}{\text{yr}} \times \frac{0.2605\text{ tonnes }CH_4}{\text{day}} \times \frac{70\text{ mole \% }CH_4}{83.85\text{ mole \% }CH_4} \times \frac{\text{tonne mole }CH_4}{16\text{ tonne }CH_4} \times \frac{\text{tonne mole gas}}{0.70\text{ tonne mole }CH_4} \times \frac{0.09\text{ tonne mole }CO_2}{\text{tonne mole gas}} \times \frac{44\text{ tonne }CO_2}{\text{tonne mole }CO_2}$$

$$\underline{E_{CO_2} = 6.54\text{ tonnes }CO_2/\text{yr}}$$

A simplified, default CH_4 emission factor can be used for venting during natural gas well drilling activities when little information is available on the drilling mud type and/or duration of the drilling activity. This emission factor shown in Table 6-3 is used in the EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017 (EPA, 2019b), also known as GHGI, for CH_4 venting from well drilling for natural gas wells. Note that GHGI does not distinguish between onshore and offshore wells or by mud type, and currently includes a default emission factor for gas wells only.

Table 6-3. Natural Gas Well Drilling Methane Emission Factors for Oil and Gas Exploration

Vented Emissions Source	Methane Emission Factor [a], Original Units ($kg\ CH_4$/well)	Methane Emission Factor, Converted to Tonnes Basis (tonnes CH_4/well)	Whole Gas Emission Factor [b], (scf gas/well)
Gas Well Drilling	52.4	0.0524	3,353

Footnotes and Sources:

[a] Radian/API, *Global Emissions of Methane from Petroleum Sources*. American Petroleum Institute, Health and Environmental Affairs Department, Report No. DR140, February 1992.

[b] Converted to whole gas volume assuming 81.6 mole % CH_4 in production using the USEPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017 (EPA, 2019b) average production segment CH_4 content in natural gas by the National Energy Modeling System (NEMS) region. The CH_4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH_4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

6.2.2 Well Testing

Well testing is conducted on certain wells to determine reservoir characteristics, hydrocarbon properties, and/or production rate. It could be performed during exploration or immediately after the well completion or workover activity to determine well characteristics. This information can be used to make decisions regarding the completion and development strategies of a well. In some cases, well tests may be necessary to determine the physical and economic viability of a particular reservoir.

Most well testing is conducted with no vented emissions, because the gas from the well during the testing activities is routed to sales. If the gas flow from the well is vented to the atmosphere, then CH_4, and possibly CO_2, emissions would occur. During well testing, gas may be recovered for sales or routed to a flare, in which case venting would not occur or would be minimized.

Emissions of CH_4 and CO_2 can be estimated from well testing activities based on the measured gas production rate or the gas-to-oil (GOR) ratio for oil wells, if known. These methods are aligned with Equation W-17a and W-17b (EPA, 2019a) according to the Greenhouse Gas Reporting Program (GHGRP).

Equation 6-1 presents the calculation of gas vented from gas well testing using the measured gas vent rate and duration of the testing period. If the gas vented during well testing is routed to a flare, the emissions should be treated like other flared sources described in Section 5.

$$V_{WT} = V_P \times T \qquad \text{(Equation 6-1)}$$

where:

V_{WT} = Gas vented in volumetric units at standard temperature and pressure (STP) conditions per well testing event, e.g., standard cubic feet (scf)/event or standard cubic meter (Sm^3)/event;

V_P = Average gas production rate in volumetric units at STP conditions per day for the gas well being tested, e.g., scf/day or Sm^3/day; and
T = Number of days that the well is tested, days/well test.

The whole gas vent rate is converted to CH_4 and CO_2 emissions based on the composition of the gas stream, in accordance with Equation 6-2 below.

$$E_x = VR \times F_x \times \frac{MW_x}{\text{molar volume conversion}} \qquad \text{(Equation 6-2)}$$

where:

E_x = Emissions of "x" in units of mass (pounds, kg, tonnes) per unit of time;
"x" = Greenhouse gas compound of interest (CH_4 or CO_2, for CO_2 rich streams);
VR = Vent rate in volumetric units at STP conditions per unit of time (e.g., scf/m or Sm^3/min);
F_x = Molar fraction of compound "x" in the vent gas stream;
MW_x = Molecular weight of compound "x"; and
Molar volume conversion = Conversion from molar volume to mass (379.3 scf/lbmole or 23.685 Sm^3/kgmole at 60°F and 14.7 psi).

Equation 6-3 presents the calculation of total gas vented from oil well testing using the GOR, oil flow rate, and duration of the testing period. The vented emissions to the atmosphere from oil well testing would be adjusted by the volume routed to a flare or recovered to sales, if applicable.

$$V_{WT} = GOR \times P_R \times T \qquad \text{(Equation 6-3)}$$

where:

V_{WT} = Gas vented in volume units at STP conditions per well testing event, e.g., scf/event or Sm^3/event;
GOR = Gas to oil ratio in standard cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities;
P_R = Average annual production rate for the oil well being tested, barrels/day; and
T = Number of days that the well is tested, days/well test.

An example of the calculation of CH_4 and CO_2 emissions from oil well testing using the GOR approach is shown in Exhibit 6-2.

EXHIBIT 6-2: Sample Calculation for Oil Well Testing-Related Emissions

INPUT DATA:

A new oil well was tested to determine the reservoir characteristics over a period of 36 hours. During the testing period, the average crude oil production rate was 4,200 barrels per day (bbl/day). The GOR for the field is 700 scf gas/bbl oil. The associated gas produced during the well test period is generally flared; however, the flare was not operated for a period of 6 hours, during which time the gas was vented to the atmosphere. A gas sample indicates that the gas molar composition is approximately 70% CH_4, 20% volatile organic compounds (VOCs), and 10% CO_2. Calculate the CH_4 and CO_2 emissions from the associated gas that is vented to the atmosphere.

CALCULATION METHODOLOGY:

The total volume of associated gas from the well test is estimated using Equation 6-3, based on the GOR, oil production rate, and the duration of the well test event. The volume of associated gas that is vented to the atmosphere is based on actual time prior to flaring that the gas was released to the atmosphere.

$$V_{\text{WellTest}} = \frac{700 \text{ scf gas}}{\text{bbl oil}} \times \frac{4{,}200 \text{ bbl oil}}{\text{day}} \times \frac{6 \text{ hours}}{\text{event}} \times \frac{1 \text{ day}}{24 \text{ hours}}$$

$$V_{\text{WellTest}} = 735{,}000 \text{ scf gas/event}$$

Emissions of CH_4 and CO_2 from the volume of associated gas vented to the atmosphere are determined using Equation 6-2 and the concentration of these constituents in the gas sample.

$$E_{CH_4} = \frac{735{,}000 \text{ scf gas}}{\text{event}} \times \frac{1 \text{ lbmole gas}}{379.3 \text{ scf gas}} \times \frac{0.70 \text{ lbmole } CH_4}{1 \text{ lbmole gas}} \times \frac{16 \text{ lb } CH_4}{1 \text{ lbmole } CH_4} \times \frac{1 \text{ tonne } CH_4}{2204.62 \text{ lb } CH_4}$$

$$E_{CH_4} = 9.84 \text{ tonnes } CH_4\text{/event}$$

$$E_{CO_2} = \frac{735{,}000 \text{ scf gas}}{\text{event}} \times \frac{1 \text{ lbmole gas}}{379.3 \text{ scf gas}} \times \frac{0.10 \text{ lbmole } CO_2}{\text{lbmole gas}} \times \frac{44 \text{ lb } CO_2}{\text{lbmole } CO_2} \times \frac{1 \text{ tonne } CO_2}{2204.62 \text{ lb } CO_2}$$

$$E_{CO_2} = 3.87 \text{ tonnes } CO_2\text{/event}$$

A simplified default CH_4 emission factor approach can be used for well testing activities, when site-specific data is unavailable. The emission factors shown in Table 6-4 for gas and oil wells, respectively, include factors for well testing events that are vented to atmosphere. These factors, used in the GHGI (EPA, 2019b), may be updated annually based on data reported from operators under the GHGRP[3].

Table 6-4. Well Testing Methane Emission Factors for Oil and Gas Exploration

Source	Methane Emission Factor [a, b], Original Units (kg CH_4/well test)	Methane Emission Factor, Converted to Tonnes Basis (tonnes CH_4/well test)	Whole Gas Emission Factor [c] (scf gas/well)
Gas Well Testing – Vented to Atmosphere	728.8	0.728	46,625
Oil Well Testing – Vented to Atmosphere	56.5	0.057	3,613

Footnotes and Sources:
[a] Calculated using 2017 GHGRP Subpart W data for each control category (EPA, 2019a).
[b] US Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks, 2019 (EPA, 2019b), https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2017
[c] Converted to whole gas volume assuming 81.6 mole % CH_4 in production using the USEPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017 (EPA, 2019b) average production segment CH_4 content in natural gas by NEMS region. The CH_4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH_4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.
Note: These factors, used in the USEPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017 (EPA, 2019b), may be updated annually based on data reported from operators under the GHGRP. Therefore, the user should periodically review emission factor updates and make an informed decision on updating the emission factor for use in the current inventory.

6.2.3 Well Completions

Well completions are associated with the final step of the well drilling. After a well is drilled, the well bore and reservoir near the well have to be cleaned. This is accomplished by producing the well tanks[4] where sand, cuttings, and other reservoir fluids are collected for recycle or disposal. This step is also useful to evaluate the well production rate to properly size the production equipment.

Reservoir and drilling fluids are removed from the wellbore during completion, in a process called ‘flowback’. Hydrocarbons, including CH_4, can be dissolved or entrained in these liquids and released to the atmosphere during the flowback process.

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[3] GHGI emission factors may be updated annually; therefore, the user should periodically review emission factor updates and make an informed decision on updating the emission factor for use in the current inventory. Important considerations for updating the emission factor include the materiality of the updated emission factor on overall emissions, EPA’s basis for the emission factor, and industry comments to GHGI regarding the emission factor, if applicable.

[4] In most countries with strict environmental regulations, the completion fluids are collected in tanks; however, there may be instances in less regulated countries where the well reservoir fluids are collected in pits during the well completion process.

6.2.3.1 Well Completions with Hydraulic Fracturing

Wells drilled in low permeability reservoirs require fracturing of the formation to allow for oil and gas to be produced. This is accomplished using high pressure fluids injected into the wellbore to hydraulically fracture the rock formation. Well completions that involve hydraulic fracturing result in a higher rate of flowback than most well completions without hydraulic fracturing, due to the large quantities of water and proppant (mainly sand) used to fracture lower permeability reservoirs. Initially, the flowback liquids are routed to open pits or tanks until the gas volume is sufficient to route the flowback to a separator where gas flow measurement is possible. In some cases, CO_2 or nitrogen (N_2) are injected into the reservoir during the energized fracture job. During flowback, CH_4 released from the flowback liquids may be vented to the atmosphere or routed to a flare.

A method known as “green completions” or “Reduced Emissions Completions (RECs)” may be utilized where the well completion gas is captured by temporary equipment brought to the site to capture the vented gas to the point that it is clean enough and can be sent to the sales line, thus avoiding or minimizing vented emissions. If green completion methods are used to recover any of the well completion emissions, the uncontrolled (vented) CH_4 emission factor must be multiplied by the non-recovered fraction associated with the green completion method. The percent recovery via green completions should be based on site-specific data.

To quantify GHG emissions from well completions with hydraulic fracturing, the preferred method is direct metering of the gas flow during flowback. If applicable, the volume of N_2 injected during fracturing should be deducted from the total recorded gas flow volume metered during flowback. Equation 6-4 below shows the calculation approach for quantifying the gas volume released during a well completion with hydraulic fracturing event when the gas flow is metered. The whole gas vent rate per event is converted to CH_4 and CO_2 emissions based on the composition of the gas stream (accounting for any CO_2 injected), in accordance with Equation 6-4, after adjusting for any gas volume that was sent to flare or recovered to sales.

$$V_{gas} = V_t - EnF \qquad \text{(Equation 6-4)}$$

where:

V_{gas} = Gas vented in volumetric units at STP conditions during flowback after sufficient quantities of gas are present to enable separation, e.g., scf/event or Sm^3/event;

V_t = Total gas flow volume measured in volumetric units at STP conditions during flowback after sufficient quantities of gas are present to enable separation, e.g., scf/event or Sm^3/event. Note that the total gas volume can be quantified as the summation of hourly meter readings during the flowback period;

EnF = Amount of N_2 injected into the well during an energized fracture job or well flowback event in volumetric unit at STP conditions, e.g., scf/event or Sm^3/event. If no gas was injected into the well, or if the injected gas is CO_2, then EnF = 0.

Gas released during the initial flowback period (typically, on the order of an hour in duration), from the period when gas is first detected until sufficient quantities of gas are present to enable separation and metering, can also be estimated based on engineering judgement or assumptions. In the USEPA GHGRP Subpart W rule (EPA, 2019a), the calculation equations for well completions with hydraulic fracturing overstates this initial unmetered period of gas venting by conservatively assuming that the rate of initial gas venting is half the average rate over the measurement period. Equation 6-5 below estimates the gas vent rate during the initial flowback period before gas measurement is possible using the overly conservative Subpart W assumption that the initial gas rate (unmetered) is half of the average measured gas rate during flowback.

$$V_i = \left(T_i \times \left(\frac{V_{gas}}{T_m} \right)\right) \div 2 \qquad \text{(Equation 6-5)}$$

where:

V_i = Gas vented in volumetric units at STP conditions during initial period of flowback to open tanks or pits, from when gas is first detected until sufficient quantities of gas are present to enable separation, e.g., scf/event or Sm^3/event;

V_{gas} = Gas vented in volumetric units at STP conditions during flowback after sufficient quantities of gas are present to enable separation, e.g., scf/event or Sm^3/event;

T_i = Cumulative amount of time of initial flowback to open tanks or pits, from when gas is first detected until sufficient quantities of gas are present to enable separation, hours

T_m = Cumulative amount of time when gas is being metered during flowback after sufficient quantities of gas are present to enable separation, hours

Exhibit 6-3 below provides an example calculation for GHG emissions from a well completion with hydraulic fracturing event.

EXHIBIT 6-3: Sample Calculation for Well Completion with Hydraulic Fracturing

INPUT DATA:

A gas well completed with hydraulic fracturing vents gas to the atmosphere for 4 hours during the initial phase of flowback until the gas volume is sufficient to route the gas to a separator. After the gas is routed to a separator, the metered gas is sent to a flare for 20 additional hours during flowback. The volume of gas metered to flare is 1.48 million scf. During the energized fracture job, 7,390 scf of N_2 was injected into the well. A gas sample indicates the CH_4 content is 70 mole %.

Calculate the volume of gas and CH_4 emissions associated with flared gas and the gas vented to the atmosphere during the initial flowback period, conservatively assuming that the gas vent rate during initial flowback (unmetered) is half that of the natural gas rate sent to flare.

CALCULATION METHODOLOGY:

1. *Calculate the emissions released from venting the initial flowback gas.* The gas volume routed to flare during flowback when the gas flow is metered is estimated using Equation 6-4.

$$V_{gas} = \frac{1{,}480{,}000 \text{ scf gas}}{\text{event}} - \frac{7{,}390 \text{ scf } N_2}{\text{event}}$$

$$\underline{V_{gas} = 1{,}472{,}610 \text{ scf gas/event}}$$

EXHIBIT 6.2-4: Sample Calculation for Well Completion with Hydraulic Fracturing (continued)

Estimate the gas volume vented to atmosphere during the initial flowback period before sufficient volume of gas is available to route the gas to the separator. The gas volume vented to the atmosphere during initial flowback is quantified using Equation 6-5, assuming that the gas vent rate during initial flowback is half that of the metered flow rate to flare.

$$V_i = \left(4 \text{ hours} \times \left(\frac{1{,}472{,}610 \text{ scf gas}}{\text{event}} \times \frac{1}{20 \text{ hours}}\right)\right) / 2$$

$$\underline{V_i = 147{,}261 \text{ scf gas/event}}$$

The whole gas vent rate is converted to CH_4 emissions based on the composition of the gas stream, in accordance with Equation 6-2.

$$E_{CH4} = \frac{147{,}261 \text{ scf gas}}{\text{event}} \times \frac{1 \text{ lbmole gas}}{379.3 \text{ scf gas}} \times \frac{0.70 \text{ lbmole } CH_4}{1 \text{ lbmole gas}} \times \frac{16 \text{ lb } CH_4}{1 \text{ lbmole } CH_4} \times \frac{1 \text{ tonne } CH_4}{2204.62 \text{ lb } CH_4}$$

$$\underline{E_{CH4} = 1.97 \text{ tonnes } CH_4}$$

2. *Calculate the emissions released from flaring the flowback gas.* Details on flaring emissions are provided in Section 5. We will assume that the "other" components in the gas analysis are primarily ethane. Emissions are calculated assuming the default 98% combustion efficiency. Emissions are calculated as shown below.

$$E_{CO2} = \left(\frac{1{,}472{,}610 \text{ scf gas}}{\text{event}} \times 1 \text{ event} \times \frac{1 \text{ lbmole gas}}{379.3 \text{ scf gas}}\right) \times$$

$$\left(\left[\frac{0.70 \text{ lbmole C (from } CH_4)}{\text{lbmole gas}} + \frac{0.30 \times 2 \text{ lbmole C (from } C_2H_6)}{\text{lbmole gas}}\right] \times \frac{0.98 \text{ lbmole } CO_2 \text{ formed}}{\text{lbmole C combusted}}\right) \times$$

$$\frac{44 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne CO}_2}{2204.62 \text{ lb CO}_2}$$

$$\underline{E_{CO2} = 98.7 \text{ tonnes CO}_2}$$

$$E_{CH4} = \frac{1{,}472{,}610 \text{ scf gas}}{\text{event}} \times 1 \text{ event} \times \frac{1 \text{ lbmole gas}}{379.3 \text{ scf gas}} \times$$
$$\frac{0.70 \text{ lbmole CH}_4}{\text{lbmole gas}} \times \frac{(1\text{-}0.98) \text{ lbmole residual CH}_4}{\text{lbmole CH}_4} \times \frac{16 \text{ lb CH}_4}{\text{lbmole CH}_4} \times \frac{\text{tonne CH}_4}{2204.62 \text{ lb CH}_4}$$

$$\underline{E_{CH4} = 0.39 \text{ tonnes CH}_4}$$

An alternative to measuring the volume of flowback gas for each well completion, as shown in Equation 6-5, is based on USEPA GHGRP Subpart W calculation methodology using Equations W-11A and W-11B (see 40 CFR 98.233(g)(1)) for subsonic and sonic flow, respectively. Industry operators have noted that the results using these Subpart W equations compared to actual measurements significantly overstate the flowback volume. A 2015 study conducted by Trimeric Corporation with the support of API investigated alternative calculation methods for estimating emissions from flowback operations. This 2015 study was an expansion on an original 2014 study, which found that the Gilbert-type correlation was able to estimate cumulative gas volumes for ten wells within 3% of the measured volume, while EPA's Equation W-11B overestimated the gas volume by 98% (Sexton et al., 2014). The Gilbert-type correlation (Gilbert, 1954) is an equation for sonic multiphase flow through a wellhead choke. The Gilbert-type correlation is shown below in Equation 6-6 in a linear rearranged form that can be used for multi-variable linear regression (Trimeric, 2015). Note that this equation is only applicable for sonic flow conditions.

$$Q_G = Q_L \times \left(\frac{P \times S^b}{c \times Q_L}\right)^{\frac{1}{a}} \qquad \text{(Equation 6-6)}$$

where:

Q_G = Gross gas rate, in thousand cubic feet per day (Mcf/day);
Q_L = Gross liquid rate, in bbl/day;
P = Upstream pressure, in psia;
S = Bean (choke) size in 1/64th inch increments; and
a, b, c = Empirically derived coefficients.

The procedure for quantifying the coefficients and the choke size to derive the total gas rate are provided in Appendix F.

This correlation allows users to take a subset of representative flowbacks to develop individual coefficients that can be used to predict gas emissions for additional flowbacks in the same field. The correlation predicts the cumulative gas volume to within 10 to 21% compared to measured volume. It can be used effectively to estimate the volume of gas from completions with hydraulic fracturing for both oil wells and gas wells (Trimeric, 2015).

If gas flow is not measured during flowback, emission factors derived from data reported under the USEPA GHGRP can be used to quantify GHG emissions from well completions with hydraulic fracturing. The emission factors shown in Table 6-5 include factors for well completions with hydraulic fracturing with and without gas being recovered (i.e., green completion or REC) instead of vented or flared for both gas and oil wells. These factors, used in the GHGI (EPA, 2019b), may be updated annually based on data reported from operators under the GHGRP.

Table 6-5. Well Completions with Hydraulic Fracturing Methane Emission Factors for Oil and Gas Exploration

Source	Methane Emission Factor [a, b], Original Units (kg CH_4/completion)	Methane Emission Factor, Converted to Tonnes Basis (tonnes CH_4/completion)	Whole Gas Emission Factor [c] (scf gas/completion)
Gas Well Completions with Hydraulic Fracturing: Uncontrolled Venting	28,800	28.8	1,842,577
Gas Well Completions with Hydraulic Fracturing: REC with Venting [d]	13,542	13.5	866,413
Oil Well Completions with Hydraulic Fracturing: Uncontrolled Venting	14,419	14.4	922,498
Oil Well Completions with Hydraulic Fracturing: REC with Venting [d]	615	0.6	39,357

Footnotes and Sources:

[a] Calculated using 2017 year-specific GHGRP Subpart W data for each control category.

[b] US Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks, 2019 (EPA, 2019b), https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2017

[c] Converted to whole gas volume assuming 81.6 mole % CH_4 in production using the USEPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017 (EPA, 2019b) average production segment CH_4 content in natural gas by NEMS region. The CH_4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH_4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

[d] REC with venting refers to venting during the initial flowback period, followed by recovery of the gas after sufficient volume of gas is available to enable separation.

Note: These factors, used in the USEPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017 (EPA, 2019b), may be updated annually based on data reported from operators under the GHGRP. Therefore, the user should periodically review emission factor updates and make an informed decision on updating the emission factor for use in the current inventory.

6.2.3.2 Onshore Completions without Hydraulic Fracturing

In well completions without hydraulic fracturing, the flowback period (also known as well cleanup) is typically shorter than that required when hydraulic fracturing is used. Therefore, the amount of CH_4 released is also typically lower and may involve flaring or venting of produced gas to the atmosphere via an open pit or tank collecting the fluids.

The most rigorous method to quantify CH_4 emissions from well completions without hydraulic fracturing is direct measurement of the gas flow rate during flowback. If gas flow is directly measured, the method for estimation is the same as for completions with hydraulic fracturing using Equation 6-4. For completions without hydraulic fracturing where the gas flow rate is not measured, Equation 6-7 below can be used to quantify the gas volume during the completion event based on the average daily production rate of gas for the initial production period (at least the first 30 days of production). The whole gas vent rate is then adjusted for the volume routed to a flare, if applicable, and converted to CH_4 and CO_2 emissions based on the composition of the gas stream, using Equation 6-2. (Note that if well completion gas is flared, emissions should be calculated using the flare emissions methodology discussed in Section 5.)

$$V_{CC} = V_{Pi} \times T \qquad \text{(Equation 6-7)}$$

where:

V_{CC} = Gas vented in volumetric units at STP conditions during flowback for well completion without hydraulic fracturing event, e.g., scf/event or Sm^3/event;

V_{Pi} = Average daily gas production rate in volumetric units at STP conditions for initial production period (at least 30 days) of well undergoing well completion without hydraulic fracturing, e.g., scf/day or Sm^3/day; and

T = Time that gas is vented to either the atmosphere or a flare during well completion without hydraulic fracturing, days.

The emission factors from Table 6-6 may be used when producing the wells to pits or tanks after the completion, in the absence of measurement or well production data.

Table 6-6. Onshore Well Completions without Hydraulic Fracturing Methane Emission Factors for Oil and Gas Exploration

Source	Methane Emission Factor [a, b], Original Units (kg CH_4/ completion)	Methane Emission Factor, Converted to Tonnes Basis (tonnes CH_4/completion)	Whole Gas Emission Factor [c] (scf gas/completion)
Gas Well Completions without Hydraulic Fracturing: Vented	1,737.6	1.74	111,173
Oil Well Completions without Hydraulic Fracturing: Vented[d]	14.1	0.014	902

Footnotes and Sources:

[a] Calculated using 2017 year-specific GHGRP Subpart W data for each control category.
[b] US Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks, 2019 (EPA, 2019b), https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2017
[c] Converted to whole gas volume assuming 81.6 mole % CH_4 in production using the USEPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017 (EPA, 2019b) average production segment CH_4 content in natural gas by NEMS region. The CH_4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH_4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.
Note: The gas well emission factor used in the USEPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017 (EPA, 2019b), may be updated annually based on data reported from operators under the GHGRP. Therefore, the user should periodically review emission factor updates and make an informed decision on updating the emission factor for use in the current inventory.
[d] The emission factor in GHGI for oil well completions without hydraulic fracturing is based on the following study: 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.

6.2.3.3 Offshore Well Completions

Methane emissions from offshore well completions can be quantified based on measured gas flow rates (Equation 6-4) or initial production rates (Equation 6-5) if the supporting data is available.

In the absence of site-specific data, CH_4 emission factors can be used to quantify emissions from offshore well completions, as presented in Table 6-7. Gas well completion data are taken from an Energy Information Administration report (EIA, 2001). The emission factor given in Table 6-7 can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH_4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

Table 6-7. Offshore Well Completion Methane Emission Factors for Oil and Gas Exploration

Source	Emission Factor [a], Original Units	Methane Emission Factor [b], Converted to Tonnes Basis	Methane Content Basis of Factor [c]
Offshore gas well completion	~8,700×10^3 scf whole gas/ completion-day	136.2 tonne/completion-day	81.6 mole %

Footnotes and Sources:
[a] EIA, U.S. Natural Gas Markets: Mid-Term Prospects for Natural Gas Supply, December 2001. Cites data for initial rates of production for completions in 2000. Offshore factor interpolated from chart "Initial Flow Rates of New Natural Gas Well Completions, 1985-2000."
[b] CH_4 emission factors converted from scf are based on 60°F and 14.7 psia, and 81.6 mole % CH_4. The CH_4 emission factors can be adjusted based on the relative concentrations of CH_4 and CO_2 to estimate CO_2 emissions.
[c] The total gas basis was converted to a CH_4 basis assuming 81.6 mole % CH_4 in production using the USEPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017 (EPA, 2019b) average production segment CH_4 content in natural gas by NEMS region.

6.2.4 Coal Seam Exploratory Drilling and Well Testing

Methane, or natural gas, may be used for drilling coal seam wells, if available at high pressures. In this case, CH_4, rather than compressed air, is used as the motive force to drill the wells and is emitted back to the atmosphere.

Methane may also be used to clean coal fines or dust that accumulates in the well. For this use, compressed gas is pumped into the well bore where it builds up pressure over a short duration

(20 minutes to one hour). Then, the gas is released rapidly to the surface, bringing the coal fines with it, as well as unloading accumulated water. The released gas may be vented or flared.

Emissions from these sources can be calculated based on a material balance approach. The emissions would be recorded either as point sources, if vented to the atmosphere, or combustion sources if vented to a flare. (If vented to a flare, emissions would be calculated as described in Section 5.) An example calculation illustrating the material balance approach follows in Exhibit 6-4.

EXHIBIT 6-5: Sample Calculation for Coal Seam Exploratory Drilling or Well Testing

INPUT DATA:

A coal bed CH_4 site is drilling three new wells with the following duration and gas consumption rates:

	Duration to Drill, days	Gas Consumption, 10^6 ft^3/day
Well 1	5	1.5
Well 2	2	1.5
Well 3	5	1.75

An additional 6.76×10^6 scf of gas per well is flared during well testing. The gas contains 10.9 mole% CO_2, 88.7 mole% CH_4, and 0.4 mole% other. Calculate the vented and flared emissions.

CALCULATION METHODOLOGY:

1. *Calculate the vented emissions.* Assuming the drilling gas is vented to the atmosphere, the total volume of gas vented is:

$$V = \left(\frac{1.5\times10^6\ ft^3}{day}\times5\ days\right)_{Well\ 1} + \left(\frac{1.5\times10^6\ ft^3}{day}\times2\ days\right)_{Well\ 2} + \left(\frac{1.75\times10^6\ ft^3}{day}\times5\ days\right)_{Well\ 3}$$

$$V = 19.25\times10^6\ \text{scf gas}$$

The corresponding CH_4 and CO_2 emissions resulting from this vented gas are:

$$E_{CH_4} = 19.25\times10^6 \text{ scf gas} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \times \frac{0.887 \text{ lbmole CH}_4}{\text{lbmole gas}} \times \frac{16 \text{ lb CH}_4}{\text{lbmole CH}_4} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CH_4} = 327 \text{ tonnes CH}_4}$$

$$E_{CO_2} = 19.25\times10^6 \text{ scf gas} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \times \frac{0.109 \text{ lbmole CO}_2}{\text{lbmole gas}} \times \frac{44 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CO_2} = 110 \text{ tonnes CO}_2}$$

2. *Calculate the emissions released from flaring the well test gas.* Details on flaring emissions are provided in Section 5. We will assume that the "other" components in the gas analysis are primarily ethane. Emissions are calculated assuming the default 98% combustion efficiency. Emissions are calculated as shown below.

$$E_{CO_2} = \left(\frac{6.76\times10^6 \text{ scf gas}}{\text{well}} \times 3 \text{ wells} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}}\right) \times \left(\frac{0.109 \text{ lbmole CO}_2}{\text{lbmole gas}} + \left[\frac{0.887 \text{ lbmole C (from CH}_4)}{\text{lbmole gas}} + \frac{0.004\times2 \text{ lbmole C (from C}_2\text{H}_6)}{\text{lbmole gas}}\right] \times \frac{0.98 \text{ lbmole CO}_2 \text{ formed}}{\text{lbmole C combusted}}\right) \times \frac{44 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CO_2} = 1{,}050 \text{ tonnes CO}_2}$$

$$E_{CH_4} = \frac{6.76\times10^6 \text{ scf gas}}{\text{well}} \times 3 \text{ wells} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \times \frac{0.887 \text{ lbmole CH}_4}{\text{lbmole gas}} \times \frac{0.02 \text{ lbmole residual CH}_4}{\text{lbmole CH}_4} \times \frac{16 \text{ lb CH}_4}{\text{lbmole CH}_4} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CH_4} = 6.9 \text{ tonnes CH}_4}$$

6.3 Oil and Natural Gas Production

6.3.1 Associated Gas Venting

When natural gas is produced with crude oil, it is often referred to as associated gas. Likewise, natural gas from wells that produce only natural gas and condensate, with no crude oil, is referred to as non-associated gas. Venting of associated gas can occur for a variety of reasons, such as lack of nearby pipeline infrastructure or insufficient pipeline or gas processing capacity.

Emissions from associated gas venting are estimated based on source-specific measurements or estimates of the vent rate and vent gas concentrations. The equation for quantifying methane (CH_4) or carbon dioxide (CO_2) emissions from associated gas venting from a continuous or non-continuous process vent using measured or estimated vent rate data is shown in Equation 6-8:

$$E_x = VR \times F_x \times \frac{MW_x}{\text{molar volume conversion}} \times T_v \qquad \text{(Equation 6-8)}$$

where:

E_x = Emissions of "x" in units of mass (pounds, kg, tonnes);
"x" = GHG compound of interest (CH_4, or CO_2 for CO_2 rich streams);
VR = Vent rate in volumetric units at STP conditions (scfh or Sm^3/hr);
F_x = Molar fraction of compound "x" in the vent gas stream;
MW_x = Molecular weight of compound "x";
Molar volume conversion = Conversion from molar volume to mass (379.3 scf/lbmole or 23.685 $Sm^3/kgmole$); and
T_v = Time duration of the venting (hours).

For quantifying GHG emissions from associated gas venting when the vent rate is unknown, an approach based on the gas-to-oil (GOR) ratio can be used. In this case, the vent rate can be estimated using the amount of oil produced and the GOR of the hydrocarbon production as shown in Equation 6-9:

$$VR = GOR \times Oil_p \qquad \text{(Equation 6-9)}$$

where:

VR = Vent rate in volumetric units at STP conditions (scfh or Sm^3/hr);
GOR = Gas-to-oil ratio (scf/bbl or $Sm^3/barrel$); and
Oil_p = Oil production rate (barrels/hr).

The whole gas volumetric emissions quantified in Equation 6-9 can be converted to CH_4 and CO_2 emissions using Equation 6-8.

Example calculations for associated gas venting using these equations based on known non-continuous and continuous vent rates are presented in Exhibit 6-5 and Exhibit 6-6, respectively.

EXHIBIT 6-5: Sample Calculation for Non-Continuous Associated Gas Venting

INPUT DATA:
A production facility in a remote location produces 5,200 barrels per day (bbl/day) of crude oil. The gas-to-oil ratio (GOR) for the field is 700. The associated gas is generally flared; however, the flare was not operated for a period of 15 days, during which time the gas was vented to the atmosphere. Process knowledge indicates that the gas molar composition is approximately 70% CH_4, 20% VOC, and 10% CO_2. Calculate the CH_4 and CO_2 emissions from the vented associated gas, excluding the flared amount.

CALCULATION METHODOLOGY:
To calculate the vented associated gas emissions, the associated gas production rate, VR, must be calculated from the GOR and the oil production rate using Equation 6-9.

$$\text{VR} = \frac{700\ \text{scf}}{\text{barrel}} \times \frac{5{,}200\ \text{barrel}}{\text{day}} \times \frac{\text{day}}{24\ \text{hours}} \times \frac{\text{hour}}{60\ \text{min}}$$

VR =2,528 scf/min

Equation 6-8 is used to calculate emissions for the venting period of 15 days during the year.

$$E_{CH_4} = \frac{2{,}528\ \text{scf}}{\text{min}} \times \frac{0.7\ \text{scf CH}_4}{\text{scf gas}} \times \frac{\text{lbmole CH}_4}{379.3\ \text{scf CH}_4} \times \frac{16\ \text{lb CH}_4}{\text{lbmole CH}_4} \times \frac{60\ \text{minutes}}{\text{hour}} \times \frac{24\ \text{hours}}{\text{day}}$$

$$\times \frac{15\ \text{days}}{\text{event}} \times \frac{1\ \text{event}}{\text{year}} \times \frac{\text{tonnes}}{2204.62\ \text{lb}}$$

$$\underline{E_{CH_4} = 731\ \text{tonnes CH}_4/\text{year}}$$

$$E_{CO_2} = \frac{2{,}528\ \text{scf}}{\text{min}} \times \frac{0.1\ \text{scf CO}_2}{\text{scf gas}} \times \frac{\text{lbmole CO}_2}{379.3\ \text{scf CO}_2} \times \frac{44\ \text{lb CO}_2}{\text{lbmole CO}_2} \times \frac{60\ \text{minutes}}{\text{hour}} \times \frac{24\ \text{hours}}{\text{day}}$$

$$\times \frac{15\ \text{days}}{\text{event}} \times \frac{1\ \text{events}}{\text{year}} \times \frac{\text{tonnes}}{2204.62\ \text{lb}}$$

$$\underline{E_{CO_2} = 287\ \text{tonnes CO}_2/\text{year}}$$

Emissions from flaring of the associated gas would be estimated using the approaches described in Section 5.

EXHIBIT 6-6: Sample Calculation for Continuous Associated Gas Venting

INPUT DATA:
The production facility described in the Exhibit 6-5 calculation is repeated for the case where no flare is installed at the facility. Thus, annual emissions occur due to continuous venting of the produced associated gas throughout the year. Calculate the CH_4 and CO_2 emissions.

CALCULATION METHODOLOGY:

Equation 6-8 and 6-9 are combined to provide the approach for estimating emissions from a continuous vent. For this example, the time duration associated with the vent is based on 365 days of operation.

$$E_{CH_4} = \frac{700\text{ scf}}{\text{barrel}} \times \frac{5{,}200\text{ barrel}}{\text{day}} \times \frac{365\text{ days}}{\text{year}} \times \frac{0.70\text{ scf }CH_4}{\text{scf gas}} \times \frac{\text{lbmole }CH_4}{379.3\text{ scf }CH_4} \times \frac{16\text{ lb }CH_4}{\text{lbmole }CH_4} \times \frac{\text{tonne}}{2204.62\text{ lb}}$$

$$\underline{E_{CH_4} = 17{,}795\text{ tonnes }CH_4/\text{year}}$$

$$E_{CO_2} = \frac{700\text{ scf}}{\text{barrel}} \times \frac{5{,}200\text{ barrel}}{\text{day}} \times \frac{365\text{ days}}{\text{year}} \times \frac{0.1\text{ scf }CO_2}{\text{scf gas}} \times \frac{\text{lbmole }CO_2}{379.3\text{ scf }CO_2} \times \frac{44\text{ lb }CO_2}{\text{lbmole }CO_2} \times \frac{\text{tonne}}{2204.62\text{ lb}}$$

$$\underline{E_{CO_2} = 6{,}991\text{ tonnes }CO_2/\text{year}}$$

Alternatively, if information on the vent rate and/or GOR is unavailable, the simplified emission factors from EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017 (EPA, 2019b), also known as GHGI, may be applied in cases where venting of associated gas occurs. Table 6-8 below presents the GHGI emission factors, which represent average GHGRP data from operators reporting associated gas venting.

Table 6-8. Associated Gas Venting Emission Factors

Region	Original Units, Methane Emission Factor [a, b] (kg/bbl)	Uncertainty (± %)	Methane Emission Factor, Tonnes Basis (tonnes CH_4/ 1,000 bbl)	Methane Content Basis of Factor [b] (mole %)	Whole Gas Emission Factor [b] (scf gas/ bbl)
Associated Gas Venting – US Average	1.4	Not specified	1.4	81.6	89

Region	Original Units, Methane Emission Factor [a, b] (kg/bbl)	Uncertainty (± %)	Methane Emission Factor, Tonnes Basis (tonnes CH_4/ 1,000 bbl)	Methane Content Basis of Factor [b] (mole %)	Whole Gas Emission Factor [b] (scf gas/ bbl)
Gulf Coast Basin (Basin 220)	0.7		0.7	81.6	47
Anadarko Basin (Basin 360)	9.7		9.7	81.6	622
Williston Basin (Basin 395)	8.9		8.9	81.6	570
Permian Basin (Basin 430)	6.5		6.5	81.6	419
"Other" US Basins	0.4		0.4	81.6	26

Footnotes and Sources:

[a] EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 – 2017 (EPA, 2019b). These values were calculated using 2017 year-specific GHGRP Subpart W data by region.

[b] These emission factors are only for operators that report venting of associated gas.

[b] Gas content taken from GHGI Annex 3.6 Table 3.6-3 for U.S. Production segment Methane Content in Natural Gas by NEMS Region (General Sources). For the lower 48 states, in 2017, methane content at 81.6 mol%. The CH_4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH_4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

Note: These factors, used in the USEPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017 (EPA, 2019b), are updated annually based on data reported from operators under the GHGRP.

6.3.2 Workovers without Hydraulic Fracturing

Well workovers refer to activities performed to restore or increase production. Workover activities involve pulling the tubing from the well to repair tubing corrosion or other downhole equipment problems. If the well has positive pressure at the surface, the well is “killed” by replacing the gas and oil in the column with a heavier fluid, such as mud or water, to stop the flow of oil and gas. A small amount of gas is released as the tubing is removed from the open surface casing. Derivation of the GRI/EPA emission factors for well workovers was based on data from a limited number of production fields collected by Pipeline Systems Incorporated (Tilkicioglu, 1990). The EPA GHGRP Subpart W references these same emission factors, as presented in Table 6-9.

Table 6-9. Production Segment Methane Emission Factors for Workovers without Hydraulic Fracturing

Source	Original Units, Methane Emission Factor [a, b, c] (scf CH_4/ workover)	Uncertainty [d] (±%)	Methane Emission Factor, Converted to Tonnes Basis (tonnes CH_4/ workover)	Methane Content Basis of Factor (mole %)	Whole Gas Emission Factor (scf gas/ workover)
Gas well workovers	2,454	924	0.0470	78.8	3,114
Oil well workovers	96	Not available	0.0018	78.8	122

Footnotes and Sources:

[a] Factors taken from: Tilkicioglu, B.H. Annual Methane Emission Estimate of the Natural Gas Systems in the United States, Phase II, Pipeline Systems Incorporated (PSI), September 1990. An EPA Gas STAR paper on installing plunger lift systems in gas wells presents a gas well workover emission factor of 2000 scf CH_4/workover, which equates to 0.0384 tonnes CH_4/workover (EPA Gas STAR, Lessons Learned - Installing Plunger Lift Systems in Gas Wells, October 2003 (EPA, 2003a). Gas STAR also reports that the number of gas well workovers conducted in a year typically ranges from 1 to 15.

[b] The methane content for the original values are not given, as per source (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).

[c] Note that EPA's Subpart W (EPA, 2019a) uses the same gas well workover emission factor (2,454 scf CH_4/workover), converted to whole gas, with a methane content basis of 78.8 mol%.

[d] Uncertainty based on a 95% confidence interval.

An example calculation is given in Exhibit 6-7 below that illustrates the use of the workover emission factors.

EXHIBIT 6-7: Sample Calculation for Workovers without Hydraulic Fracturing

INPUT DATA:

An operator performed 10 workovers without hydraulic fracturing in a calendar year on various gas wells in a given production area. There is no flare in place so any gas not captured to sales is assumed to vent to atmosphere. Gas composition is estimated to contain 70 mole % CH_4, and 9 mole % CO_2. Calculate the CH_4 and CO_2 emissions from the vented gas from the workovers per year.

CALCULATION METHODOLOGY:

To calculate the vented CH_4 and CO_2 emissions, the emission factor from Table 6-9 can be used. The methane emission factor can be used to calculate methane emissions, while the whole gas factor can be used for CO_2.

Gas well workovers without hydraulic fracturing:

$$E_{CH_4} = \frac{10 \text{ workovers}}{\text{year}} \times \frac{3{,}114 \text{ scf gas}}{\text{workover}} \times \frac{0.70 \text{ scf } CH_4}{1 \text{ scf gas}} \times \frac{\text{lbmole } CH_4}{379.3 \text{ scf } CH_4} \times \frac{16 \text{ lb } CH_4}{\text{lbmole } CH_4} \times \frac{\text{tonne}}{2204.62 \text{ lb } CH_4}$$

$$\underline{E_{CH_4} = 0.42 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2} = \frac{10 \text{ workovers}}{\text{year}} \times \frac{3{,}114 \text{ scf gas}}{\text{workover}} \times \frac{0.09 \text{ scf } CO_2}{1 \text{ scf gas}} \times \frac{\text{lbmole } CO_2}{379.3 \text{ scf } CO_2} \times \frac{44 \text{ lb } CO_2}{\text{lbmole } CO_2} \times \frac{\text{tonne}}{2204.62 \text{ lb } CO_2}$$

$$\underline{E_{CO_2} = 0.15 \text{ tonnes } CO_2/\text{yr}}$$

6.3.3 Workovers with Hydraulic Fracturing

For workovers with hydraulic fracturing, injected gas, water, oil, and proppant are used to re-fracture and open new fractures in existing low permeability gas reservoirs. During flowback from a well workover activity with hydraulic fracturing, gas entrained in the flowback fluids and produced gas may be vented to the atmosphere, recovered or flared.

Emissions can be estimated from workovers with hydraulic fracturing similar to the estimation methods described in Section 6.2.3.1 for completions with hydraulic fracturing. Direct measurement is considered the most accurate approach (refer to methods in Section 6.2.3.1); however, when this is not practical or feasible, emission factors listed in Table 6-5 may be applied. These emission factors, cited from the GHGI and calculated using 2017 year-specific GHGRP Subpart W data, are also applicable to workovers with hydraulic fracturing.

6.3.4 Well Venting from Liquids Unloading

Well unloading (liquids unloading) are sometimes performed to remove liquids that accumulate in the wellbore. Throughout the lifecycle of a well, specific conditions may lead to liquid accumulation, such as a decrease in gas velocity in the well, a decrease in reservoir pressure, or changes in liquid to gas ratios (Allen, 2014). Conditions that lead to liquid accumulation can inhibit the flow of gas to the sales line and therein cause a decline in production.

Certain methods of well unloading can result in gas venting which includes well unloading with and without plunger lift systems.

- Non-plunger lift well unloading typically occurs manually, in which an operator diverts the gas to an atmospheric tank (blowdown tank) and away from the production separator that operates at higher pressure. The increased pressure gradient allows for higher gas flow, which lifts the liquid out of the well. Gas entrained in the liquid is vented to atmosphere once it reaches the atmospheric tank.
- Well unloading with plunger lifts can also be conducted manually or in an automated mode. With a plunger lift system, the well is shut-in and the plunger is released, allowing the plunger to drop to the bottom of the well. The well is then re-opened, and gas pushes the plunger to the top of the well with a slug of liquid on top. Certain cases can be void of GHG emissions, if the plunger reaches the top of the wellbore and gas and liquid are routed to the production separator. However, if the plunger does not reach the top of the well as anticipated, flow may be directed to an atmospheric tank (i.e., ensuing an increased pressure gradient) which will lift the plunger out of the wellbore.

The quantity of gas vented from well unloading depends on the duration of the unloading event, which can be calculated based on field conditions (formation, depth, etc.). Direct measurements are considered the most accurate method for quantifying emissions from well unloading. When this is not practical or feasible, an engineering calculation approach is recommended. EPA's GHGRP, specifically Subpart W for Petroleum and Natural Gas Systems, contains calculation methods for estimating the volumetric emissions of well unloading. EPA's Subpart W breaks out the equations by type (Equation W-8 for non-plunger systems and Equation W-9 for plunger systems); however, those equations have been integrated in Equation 6-10 below:

$$\mathrm{VR} = \left(\frac{\#\ \mathrm{events}}{\mathrm{well\text{-}year}} \times \left(0.37\times10^{-3}\frac{ft^2}{lb}\right) \times \mathrm{D}^2 \times \mathrm{Depth} \times \mathrm{P}\right) + (\mathrm{SFR} \times (\mathrm{HR} - \mathrm{X}) \times \mathrm{Z}) \quad \text{(Equation 6-10)}$$

where:

VR = Gas vent rate (scf/well-year);

D = For plunger lift systems, tubing diameter (inches), for non-plunger systems, casing diameter (inches);
Depth = For plunger lift systems, tubing depth to plunger bumper (feet); for non-plunger systems, well depth from top of well or lowest packer to the bottom of the well (feet);
P = Flow-line pressure (psig);
SFR = Average flow-line rate of gas for well at standard conditions (scf/hr);
HR = Hours that well was left open to atmosphere during unloading event;
X = Hours for average well unloading. For plunger lift systems, use 0.5, and for non-plunger systems, use 1; and
Z = If HR < 1.0, then Z is 0, if HR ≥ 1.0, then Z is 1.

Note that Equation 6-11 above from EPA's GHGRP Subpart W calculates CH_4 and CO_2 emissions from well liquid unloading on a whole gas volumetric basis. The conversion from whole gas volumetric emissions to CH_4 and CO_2 mass emissions is described in Equation 6-2.

An alternative emission estimation method for liquids unloading for wells using automated plunger lift relies on the duration of the venting activity and the gas production rate of the well, which has been determined to be a more accurate measurement approach than the GHGRP Subpart W method (Pasci, et al, 2020). Equation 6-11 below can be used to quantify the vent rate for automated plunger lift well unloading events, based on the production rate of gas in the well and amount of time that the well vents to atmosphere during the unloading cycle. Note that the equation is only applicable to liquids unloading using plunger lift.

$$\mathrm{VR} = \frac{\sqrt{(\mathrm{P_{shut}} - \mathrm{P_{atm}})}}{\sqrt{(\mathrm{P_{line}} - \mathrm{P_{sep}})}} \times \mathrm{SFR_p} \times \mathrm{T_p} \qquad \text{(Equation 6-11)}$$

where:

VR = Vent rate (scf/hr)
P_{shut} = The shut-in pressure to which the well builds while the plunger is being dropped (psia);
P_{atm} = The local atmospheric pressure (psia);
P_{line} = The normal line pressure for the well during normal production operations (psia);
P_{sep} = The separator operating pressure (psia);
SFR_p = The average gas production rate of the well (scf/hr); and
T_p = The venting time for the well during the unloading event (hr).

A more detailed method for estimating emissions from well unloading is also provided in Appendix B. Exhibit 6-8 illustrates the use of the engineering equation 6-10 to estimate well unloading emissions.

EXHIBIT 6-8: Sample Calculation for Estimating Well Unloading Emissions

INPUT DATA:

A well is unloaded once per month (or a total of 12 times per year) without the use of a plunger system. The casing diameter is 10 inches, the well depth is 12,000 feet, and the flow-line pressure is 250 psig. The average flow-line rate for gas in the well at standard conditions is 35,000 scf/hr, and the unloading event duration is 1 hour. The gas that is vented contains approximately 80 mole % CH_4 and 3 mole % CO_2. Calculate the CH_4 and CO_2 emissions.

CALCULATION METHODOLOGY:

The unloaded gas is assumed to be ideal (i.e., Z is assumed to be 1). The CH_4 emissions are estimated using Equation 6-10.

$$\mathrm{VR} = \left[\left(\frac{12\text{ events}}{\text{well-year}} \times \frac{0.37\times10^{-3}\text{ ft}^2}{\text{lb}} \times (10\text{ inches})^2 \times 12{,}000\text{ feet} \times 250\text{ psig}\right) + \left(\frac{35{,}000\text{ ft}^3}{\text{hr}} \times (1\text{ hr-1hr}) \times 1\right)\right]$$

VR = 1,332,000 scf/yr

$$E_{CH4} = \frac{1{,}332{,}000 \text{ scf}}{\text{yr}} \times \frac{0.80 \text{ lbmol } CH_4}{\text{lbmol gas}} \times \frac{\text{lbmole } CH_4}{379.3 \text{ scf } CH_4} \times \frac{16 \text{ lb } CH_4}{\text{lbmole } CH_4} \times \frac{\text{tonnes}}{2204.62 \text{ lb}}$$

$\underline{E_{CH4} = 20.39 \text{ tonnes } CH_4/\text{yr}}$

Similarly, CO_2 emissions are estimated using the same equation as used for CH_4, with the concentration and molecular weight for CO_2 substituted into the equation:

$$E_{CO2} = \frac{1{,}332{,}000 \text{ scf}}{\text{yr}} \times \frac{0.03 \text{ scf } CO_2}{\text{scf gas}} \times \frac{\text{lbmole } CO_2}{379.3 \text{ scf } CO_2} \times \frac{44 \text{ lb } CO_2}{\text{lbmole } CO_2} \times \frac{\text{tonnes}}{2204.62 \text{ lb}}$$

$\underline{E_{CO2} = 2.10 \text{ tonnes } CO_2/\text{yr}}$

When wellbore information is not available, the simplified emission factors in Table 6-10 can be used to estimate emissions from well venting during liquids unloading. These emission factors in Table 6-10 below include the volumetric emissions in scf gas per well unloading event, and should be adjusted for site specific operating parameters using gas composition and number of unloading events where gas is vented to the atmosphere. For operators outside of the US, the average emission factors from Table 6-10 can be applied.

Table 6-10. Well Unloading Vented Emission Factors for Wells

Source	Original Units, Methane Emission Factor (scf CH_4/event)	Uncertainty (± %) [a]	Methane Emission Factor, Converted to Tonnes Basis (tonnes CH_4/event)	Methane Content Basis of Factor (mole %) [b]	Whole Gas Emission Factor [c] (scf gas/event)
Well Unloading with Plunger Lifts – by U.S. Region [d]					
Appalachia – (<100 events/well-year)	5,100	47.0	0.098	98.6	5,172
Appalachia – (>100 events/well-year)	1,260	66.7	0.024	98.6	1,278
Gulf Coast – (<100 events/well-year)	9,650	28.5	0.185	98.4	9,807
Gulf Coast – (>100 events/well-year)	1,260	66.7	0.024	98.4	1,280
Midcontinent – (<100 events/well-year)	6,400	56.3	0.123	97.8	6,544
Midcontinent – (>100 events/well-year)	300	55.0	0.006	97.8	307
Rocky Mountain – (<100 events/well-year)	12,600	38.1	0.241	87.3	14,433
Rocky Mountain – (>100 events/well-year)	1,400	85.7	0.027	87.3	1,604
Well Unloading without Plunger Lifts – by U.S. Region [d]					
Appalachia	4,550	91.2	0.087	98.6	4,615
Gulf Coast	13,300	27.1	0.255	98.4	13,516
Midcontinent	47,800	50.4	0.916	97.8	48.875
Rocky Mountain	15,200	38.2	0.291	87.3	17,411
Well Unloading with Plunger Lifts – Average [e]					
Plunger lift, ≤ 100 events/year	9,650	28.5	0.185	85.3	11,308
Plunger lift, > 100 events/year	1,260	66.7	0.024	83.9	1,503
Well Unloading without Plunger Lifts – Average [e]					
Non-plunger, ≤ 10 events/year	21,500	75.8	0.412	89.2	24,109
Non-plunger, 10 < events/year ≤ 50	24,100	109	0.462	93.8	25,690
Non-plunger, > 50 events/year	35,000	51.4	0.670	95.9	36,512

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval from the data used to develop the original emission factors.

[b] Gas content is volume % based on field measurements from respective study.

[c] Whole gas emission factors converted from original units using methane content from respective study.

[d] Methane emission factor, uncertainty, and methane content from published study. Littlefield, James, Joe Marriott, Greg Schivley, and Timothy Skone. (2017). *Synthesis of Recent Ground-level Methane Emission Measurements from the U.S. Natural Gas Supply Chain*. Journal of Cleaner Production 148, 118-126. http://dx.doi.org/10.1016/j.jclepro.2017.01.101.

[e] Methane emission factor, uncertainty, and methane content from published study. Allen, David, et al. (2014). *Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquid Unloadings*. Environmental Science and Technology 49, 1, 641-648. http://dx.doi.org/10.1021/es504016r

Emission factors in Table 6-10 above are based on methane emitted per well unloading event. When the number of unloading events is not available, the simplified emission factors in Table 6-11 below are provided on a per well basis. These factors are based on data from the GHGI (EPA, 2019b). The values below are taken from 2017 data.

Table 6-11. Liquid Unloading Vented Emission Factors by Well

Type of Event	Original Units, Methane Emission Factor [a] (kg CH_4/ well-year)	Uncertainty (± %)	Methane Emission Factor, Converted to Tonnes Basis (tonnes CH_4/ well-year)	Methane Content Basis of Factor [b] (mole %)	Whole Gas Emission Factor [b] (scf gas/ well-year)
Liquid Unloading, plunger	1,774	Not specified	1.77	81.6	113,466
Liquid Unloading, non-plunger	2,792	Not specified	2.79	81.6	178,531

Footnotes and Sources:

[a] EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 – 2017. (EPA, 2019b). These values were calculated using 2017 year-specific GHGRP Subpart W data for each control category.

[b] Gas content taken from GHGI Annex 3.6 Table 3.6-3 for U.S. Production segment Methane Content in Natural Gas by NEMS Region (General Sources). For the lower 48 states, in 2017, methane content at 81.6 mol%. The CH_4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH_4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

Note: These factors, used in the USEPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017 (EPA, 2019b), are updated annually based on data reported from operators under the GHGRP.

6.3.5 Casing Gas Vents

6.3.5.1 Heavy Oil and Crude Bitumen Casing Gas Vents

Casing gas vents are a particular concern for heavy oil and crude bitumen wells. Heavy oil wells are relatively shallow (typically 300 to 900 m deep) and, thus are characterized by low reservoir pressures (typically 4000 kPa or less). To achieve reasonable flow potential, it is necessary to relieve gas pressure from the well bore. The wells are not usually equipped with a production packer (a controller that isolates the annulus from the formation), which allows the well pressure to be controlled using the casing vent. Because of the low volumes of gas associated with primary heavy oil casing gas, the gas may be vented directly to atmosphere. For thermal heavy oil projects, the gas is usually flared or conserved because of the potential for hydrogen sulfide (H_2S) in the gas.

Casing gas venting associated with heavy oil production may result in emissions of CH_4 contained in the gas, and possibly CO_2 emissions. Site-specific volumetric flow rate and CH_4 concentration data (and CO_2 if present) provide the most rigorous estimation of these emissions. However, in the absence of site-specific data, the simplified casing gas vented emission factors presented in Tables 6-12 and 6-13 can be used.

Table 6-12 provides casing gas total hydrocarbon (THC) vented emission factors on a heavy oil production throughput basis. The base THC factors are taken from the Canadian Association of Petroleum Producers (CAPP, 2003). The THC factors in CAPP are based on an assumed percentage vented for each type of oil. However, the factors can be adjusted using actual site-specific venting percentages if they are available and different from the defaults shown in the table.

Table 6-12. Heavy Oil and Crude Bitumen Casing Gas Vented CH_4 Emission Factors – Throughput Basis

Type of Oil	Original Units, Total Hydrocarbon Emission Factor [a] (m^3 THC/m^3 oil produced)	Uncertainty (± %)	Methane Emission Factor [b] (tonnes CH_4/ 1,000 barrels oil)	Methane Content Basis of Factor [b] (mole %)	Whole Gas Emission Factor [c, d] (scf gas/barrel oil produced)
Primary Heavy Oil (63.2% casing gas vented) [e]	37.4	Not specified	3.28	81.6	210
Thermal Heavy Oil (4.7% casing gas vented) [e]	2.53		0.223	81.6	14.2
Crude Bitumen (18% casing gas vented) [e]	2.3		0.207	81.6	12.9

Footnotes and Sources:

[a] Canadian Association of Petroleum Producers (CAPP), *Calculating Greenhouse Gas Emissions*, Table 1-14, Canadian Association of Petroleum Producers, Publication Number 2003-03, April 2003.

[b] For conversion to methane, the actual composition or an assumed 81.6 mol% can be assumed, from GHGI Annex 3.6 Table 3.6-3 for U.S. Production segment Methane Content in Natural Gas by NEMS Region (General Sources).

[c] Whole gas emission factor conversion assumes that the gas released comprises 100% (mol or vol) of hydrocarbon; no inerts present in the gas composition.

[d] Emission factors converted from m^3 are based on 15°C and 1 atm

[e] Percentage shown is the assumed percent of total casing gas vented. If the actual percent casing gas vented is known, the factor and percentage shown for each crude type can be used to estimate the CH_4 emission factor for the actual percent casing gas vented if it is different from the default value shown in the table.

If the oil production throughput is not known, Table 6-13 can be used. This table provides simplified casing gas vented THC emission factors for active and suspended wells based on data from Alberta, Canada (CAPP, 2002). The active and suspended well emission rate data were based on 883 and 910 wells, respectively.

Table 6-13. Heavy Oil and Crude Bitumen Casing Gas Vented Methane Emission Factors – Well Basis

Source	Original Units, Total Hydrocarbon Emission Factor [a] (m³ THC/well-day)	Uncertainty (± %)	Methane Emission Factor [b, c] (tonnes CH_4/ well-day)	Methane Content Basis of Factor [c] (mole %)	Whole Gas Emission Factor [b, d] (scf gas/well-day)
Active Wells	37.1	Not specified	0.0205	81.6	1,310
Suspended Wells	20.1	Not specified	0.0111	81.6	710

Footnotes and Sources:

[a] Canadian Association of Petroleum Producers (CAPP), *Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities*, table on page 3-24, Publication Number 2002-0009, May 2002. Factors shown are based on data collected in Alberta, and were converted from a total gas basis to a CH_4 basis using the CH_4 content shown in the table.

[b] Emission factors converted from m^3 are based on 15°C and 1 atm.

[c] For conversion to methane, 81.6 mol% can be assumed, from GHGI Annex 3.6 Table 3.6-3 for U.S. Production segment Methane Content in Natural Gas by NEMS Region (General Sources).

[d] Whole gas emission factor conversion assumes that the gas released comprises 100% (mol or vol) of hydrocarbon; no CO_2 present in the gas composition.

The THC emission factors from the two CAPP guidance documents were converted to CH_4 emission factors using a default CH_4 gas content of 81.6 mole % in the production segment from the GHGI for methane content in natural gas (EPA, 2019b). The casing gas CH_4 emission factors can be adjusted based on the CH_4 content of the site-specific gas if the natural gas has a CH_4 content significantly different from the default basis. Also, if the gas at the site contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

An example calculation is given in Exhibit 6-9 that illustrates the use of the casing gas vent emission factors. It should be emphasized that measurement data is preferred over default emission factors, as noted above.

EXHIBIT 6-9: Sample Calculation for Heavy Oil Casing Gas Vented Emissions

INPUT DATA:

An oil and gas production facility produces 100 bbl/day of primary heavy crude oil. The facility operates 365 days a year. The average CH_4 content of the gas is 70 mole %; there is also 9 mole % CO_2 in the gas. Calculate the CH_4 and CO_2 emissions.

CALCULATION METHODOLOGY:

Emissions are calculated by multiplying the oil throughput by the "primary heavy oil" whole gas emission factor from Table 6-12, and adjusted to the site specific basis of 70 mole % CH_4.

Because the gas contains a significant quantity of CO_2, emissions of CO_2 are also estimated using the relative CO_2 and CH_4 contents in the gas.

$$E_{CH_4} = \frac{100 \text{ bbl crude}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{210 \text{ scf gas}}{\text{barrel oil produced}} \times \frac{0.70 \text{ lbmol } CH_4}{1 \text{ lbmol gas}}$$

$$\times \frac{\text{lbmol } CH_4}{379.3 \text{ scf } CH_4} \times \frac{16 \text{ lb } CH_4}{\text{lbmol } CH_4} \times \frac{1 \text{ tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CH_4} = 102.7 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2} = \frac{100 \text{ bbl crude}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{210 \text{ scf gas}}{\text{barrel oil produced}} \times \frac{0.09 \text{ lbmol } CO_2}{1 \text{ lbmol gas}}$$

$$\times \frac{\text{lbmol } CO_2}{379.3 \text{ scf } CO_2} \times \frac{44 \text{ lb } CO_2}{\text{lbmol } CO_2} \times \frac{1 \text{ tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CO_2} = 36.3 \text{ tonnes } CO_2/\text{yr}}$$

6.3.5.2 Low Pressure Gas Well Casing Vents

Casing gas migration from low-pressure natural gas wells can result in CH_4 emissions and possibly CO_2 emissions, if CO_2 is present in the gas. This migration results from the flow of gas around the outside of a well casing. It is typically caused by gas migrating from one or more shallow, low-productivity gas bearing zones that were penetrated during the drilling process or as a result of natural processes within the soil (CAPP, 2002). Similar to the approach for crude oil casing gas venting, site-specific measurements provide the most rigorous estimate of low-pressure gas well casing emissions. In the absence of site-specific data, the following emission factor from page 3-25 of the CAPP document, *Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities*, can be used (CAPP, 2002):

3.85 m^3 gas/well-day (Original Units)[a,b]
0.00213 tonnes CH_4/well-day (Converted)[c]

Footnotes and Sources:

[a] Canadian Association of Petroleum Producers (CAPP), *Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities*, Publication Number 2002-0009, May 2002.

[b] Uncertainty is not specified for this value.

[c] Note that the THC factor was converted to a CH_4 emission factor assuming 81.6 mole % CH_4 in the gas, according to the GHGI methane content for natural gas (EPA, 2019b).

The casing gas migration emission factor was based on test data of the "…average vent rate for wells with gas migration problems…" (CAPP, 2002).

An example calculation is given in Exhibit 6-10 that demonstrates the use of the gas well casing emission factor.

EXHIBIT 6-10: Sample Calculation for Low-Pressure Casing Gas Migration Emissions

INPUT DATA:

An oil and gas production facility has three low pressure wells. Sampling data show that casing gas migration occurs, but the emission rate has not been measured. The average CH_4 content of the gas is 70 mole %; there is also 9 mole % CO_2 in the gas. Calculate the CH_4 and CO_2 emissions.

CALCULATION METHODOLOGY:

Emissions are calculated by multiplying the number of wells by the casing gas migration CH_4 emission factor. The base casing gas migration CH_4 emission factor is also adjusted from the default basis of 81.6 mole % CH_4 from GHGI to the site-specific basis of 70 mole % CH_4. Because the gas contains a significant quantity of CO_2, emissions of CO_2 are also estimated using the relative CO_2 and CH_4 contents in the gas.

$$E_{CH_4} = 3 \text{ wells} \times \frac{0.00213 \text{ tonnes } CH_4}{\text{well-day}} \times \frac{365 \text{ day}}{\text{year}} \times \frac{70 \text{ mole \% } CH_4}{81.6 \text{ mole \% } CH_4}$$

$$\underline{E_{CH_4} = 2.00 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2} = 3 \text{ wells} \times \frac{0.00213 \text{ tonnes } CH_4}{\text{well-day}} \times \frac{365 \text{ day}}{\text{year}} \times \frac{70 \text{ mole \% } CH_4}{81.6 \text{ mole \% } CH_4} \times \frac{\text{tonne mole } CH_4}{16 \text{ tonne } CH_4}$$
$$\times \frac{\text{tonne mole gas}}{0.70 \text{ tonne mole } CH_4} \times \frac{0.09 \text{ tonne mole } CO_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne } CO_2}{\text{tonne mole } CO_2}$$

$$\underline{E_{CO_2} = 0.71 \text{ tonnes } CO_2/\text{yr}}$$

6.3.6 Natural Gas Driven Pneumatic Controllers

Pneumatic controllers are used in oil and gas operations for maintaining a process condition, such as liquid level or pressure conditions for process control. In the production segment, natural gas is often used to operate pneumatic controllers. Natural gas-driven pneumatic controllers are a source of CH_4 emissions (and CO_2, if present in the gas). Pneumatic controllers may be designed to vent gas continuously (such as when designed with a pilot gas stream) or intermittently (i.e., only when actuated). Low vent and no vent pneumatic controllers may also be used. Pneumatic controllers may also be operated using compressed air, resulting in no venting of CH_4.

While this section is organized by controller type (i.e., continuous and intermittent vent), if the controller type is unknown, the default emission factors presented in Section 6.3.6.3 can be used.

6.3.5.3 Continuous Vent Controllers

Continuous vent pneumatic controllers are designed to release gas continuously from the valve control pilot, and also release gas with every actuation of the valve. The rate at which the continuous release occurs is often referred to as the bleed rate. The EPA Gas STAR program defines a pneumatic controller that bleeds more than 6 scfh as a “high-bleed” controller, with “low-bleed” controllers venting less than 6 scfh (EPA, 2003d)[5]. Other reporting programs, such as the EPA GHGRP, have adopted the same definitions of high and low bleed pneumatic controllers.

One approach for estimating CH_4 emissions (and CO_2 emissions, if CO_2 is present in the gas stream) from continuous vent gas-driven pneumatic controllers is to use site-specific controller measurements or manufacturers’ data. The manufacturer’s data assumes that the controller is operating properly and the site conditions, e.g., motive gas pressure and density, are aligned with the manufacturer’s specifications, which often is not the case. The manufacturer emission rates tend to be lower than emissions observed for the same controllers in the field due to actual operating conditions and maintenance practices.

Another approach to calculate the emissions from a continuous bleed pneumatic controller is to calculate the volume of gas vented as shown in Equation 6-12, from the Gas Processors Suppliers Association *Engineering Data Book*, Equation 3-14 (GPSA, 2016).

$$Q = 16{,}330 \times \left(1+\beta^4\right) \times (d)^2 \times \sqrt{H\times[29.32+(0.3\times H)]} \times \sqrt{\frac{560}{(460+T_f)}} \times \sqrt{\frac{0.6}{G_f}} \qquad \text{(Equation 6-12)}$$

where:

Q = Gas flow rate, scf/day;
β = Ratio of the orifice diameter to the internal diameter of the pipe/tubing, dimensionless;
d = orifice diameter, in;
H = pressure, inches Hg;
T_f = Flowing temperature of gas, °R; and
G_f = Relative density (specific density) at flowing temperature of gas, dimensionless.

After calculating the volume of gas loss, CH_4 and CO_2 emissions can then be calculated using the CH_4 and CO_2 content of the gas, such as described in Equation 6-2.

Alternatively, default whole gas emission factors by controller type are provided in Table 6-14 for continuous operating controllers. Table 6-14 also presents the corresponding CH_4 emission

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[5] The bleed rate refers to the flow of motive gas through a bleed port to manage pressure in the actuation space for control purposes. The bleed rate is not an inherent property of a controller itself, but is a function of both the size of the restriction orifice and the supply gas pressure.

factors, converted using 81.6 mole % CH_4 from the GHGI (EPA, 2019). The CH_4 emission factors can be adjusted based on the CH_4 content of the site-specific gas used to drive the controllers if the natural gas is significantly different from the default basis of 81.6 mole %. Also, if the pneumatic controllers are driven with gas that contains significant quantities of CO_2, the CH_4 emission factors can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

For the production segment, the continuous vent (high and low) and production average pneumatic controller emission factors shown in Table 6-14 are taken from the 2019 API methane pneumatic controller emissions study (Pacsi, 2019).

Table 6-14. Natural Gas-Driven Pneumatic Controller Emission Factors for Continuous Vent Controllers in Production

Controller Type	Original Units, Emission Factor (whole gas basis)	Uncertainty (±%)	Methane Emission Factor (Converted)[a] (scf CH_4/ controller-hr)	Methane Content Basis of Factor[a] (mole %)	Methane Emission Factor (Converted)[a,d] (tonnes CH_4/ controller-yr)
API Study Emission Factors[b]					
High bleed [b]	16.4 scf gas/hr/controller	Not specified	13.4	81.6	2.25
Low bleed [b]	2.6 scf gas/hr/controller		2.1	81.6	0.36
EPA GHGRP Subpart W Emission Factors[c]					
High bleed[c]	37.3 scf gas/hr/controller	Not specified	30.4	81.6	5.11
Low bleed[c]	1.39 scf gas/hr/controller		1.13	81.6	0.191

Footnotes and Sources:

[a] Conversion from whole gas to methane was calculated assuming 81.6 mole % CH_4 in the gas, according to the GHGI methane content for natural gas (EPA, 2019b). Emission factors converted from m^3 are based on 15°C and 1 atm.

[b] API working paper, *Pneumatic Controller Inventory and Measurement at 67 Oil and Gas Sites in the Western United States,* 2020.

[c] EPA GHGRP Subpart W Table W-1A. (EPA, 2019a).

[d] Annual emission factor based on 8,760 hr/yr operation.

An alternative example of the classification of high bleed and low bleed, using a 1996 GRI/EPA natural gas emissions study, is provided in Appendix B (Shires, et al, 1996a).

An example calculation is provided below in Exhibit 6-11 that demonstrates the use of the pneumatic controller emission factors.

EXHIBIT 6-11: Sample Calculation for Gas-Driven Pneumatic Controller Emissions

INPUT DATA:

A gas production facility has 80 natural gas-driven low bleed pneumatic controllers. The average CH_4 content of the gas is 70 mole %. There is also 9 mole % CO_2 in the gas so CO_2 emissions from the pneumatic controllers are also estimated. Calculate the CH_4 and CO_2 emissions using the API study emission factor for low bleed controllers.

CALCULATION METHODOLOGY:

Emissions are calculated by multiplying the number of pneumatic controllers by the emission factor from Table 6-14.

The base pneumatic controller CH_4 emission factor is also adjusted from the default basis provided in Table 6-14 of 81.6 mole % CH_4 to the site-specific basis of 70 mole % CH_4. Because the gas contains a significant quantity of CO_2, emissions of CO_2 are also estimated using the whole gas emission factor and relative CO_2 and CH_4 contents in the gas.

$$E_{CH_4} = 80 \text{ pneumatic controllers} \times \frac{2.1 \text{ scf } CH_4}{\text{hr-controller}} \times \frac{70 \text{ mole \% } CH_4}{81.6 \text{ mole \% } CH_4} \times \frac{\text{lbmole } CH_4}{379.3 \text{ scf } CH_4} \times \frac{16 \text{ lb } CH_4}{\text{lbmole } CH_4} \times \frac{\text{tonne } CH_4}{2204.62 \text{ lb } CH_4} \times \frac{8760 \text{ hr}}{\text{yr}}$$

$$\underline{E_{CH_4} = 24.2 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2} = 80 \text{ pneumatic controllers} \times \frac{2.1 \text{ scf gas}}{\text{hr-controller}} \times \frac{0.09 \text{ lbmol } CO_2}{1 \text{ lbmol gas}} \times \frac{\text{lbmole } CO_2}{379.3 \text{ scf } CO_2} \times \frac{44 \text{ lb } CO_2}{\text{lbmole } CO_2} \times \frac{\text{tonne } CO_2}{2204.62 \text{ lb } CO_2} \times \frac{8760 \text{ hr}}{\text{yr}}$$

$$\underline{E_{CO_2} = 7.0 \text{ tonnes } CO_2/\text{yr}}$$

6.3.5.4 Intermittent Operating Controllers

The GHGRP defines intermittent vent[6] pneumatic controllers as automated flow control devices, powered by pressurized natural gas, that discharge all or a portion of the full volume of the actuator on an intermittent basis, not continuously (EPA, 2019a). The actual volume vented from

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[6] Also commonly referred to as intermittent 'bleed' pneumatic controllers. This definition of intermittent controllers only includes snap-acting controllers; there are also a class of intermittent controllers called throttling actuator controllers, which are covered by this definition. For more information, refer to the Simpson paper (Simpson, 2014).

an intermittent vent pneumatic controller is a function of the volume released per actuation, the frequency of actuation, and the gas supply pressure.

To estimate CH_4 emissions from intermittent vent pneumatic controllers, site-specific controller measurements or manufacturers' data may be used to estimate the vent rate per actuation, combined with the estimated number of actuations per controller during a reporting year. As previously stated for continuous controllers, the manufacturer's data may understate emissions due to different operating and maintenance conditions for controllers installed in the field. An approach to calculate the volume of gas vented from an intermittent vent pneumatic controller is shown in Equation 6-13 (Simpson, 2014).

$$\mathrm{Vol} = \left(\frac{\pi}{4} \times \mathrm{ID}^2 \times \mathrm{L_{pipe}} \times \Delta \mathrm{Vol_{bonnet}}\right) \times \left(\frac{\mathrm{P_{control}} + \mathrm{P_{atm}}}{\mathrm{P_{std}}}\right) \times \mathrm{N_{act}} \qquad \text{(Equation 6-13)}$$

where:

Vol = Volume of gas vented per year from an intermittent vent pneumatic controller (scf/yr or scm/yr);
ID = Inside diameter of piping (ft or m);
L_{pipe} = Length of all piping in system (ft or m);
ΔVol_{bonnet} = The change in the physical volume of a pneumatic valve actuator when changed from at rest to fully actuated (scf or scm);
$P_{control}$ = Pressure of the supply gas system (psig or kPag);
P_{atm} = Local atmospheric pressure (psia or kPaa);
P_{std} = Standard pressure (psia or kPaa); and
N_{act} = Estimated number of actuations per controller per year (actuations/yr).

Methane emissions may be estimated for intermittent vent pneumatic controllers using average emission factors for intermittent vent pneumatic controllers as presented in Table 6-15. These emission factors are based on measurements of over 260 pneumatic controllers in the US (API, 2020), and represent intermittent vent pneumatic controllers in normal operation and those classified as malfunctioning. Higher than expected vent rate emissions from malfunctioning intermittent pneumatic controllers were observed in a minority fraction of the population tested. Actions taken to minimize the number of malfunctioning pneumatic controllers, such as a proactive monitoring and repair program, may result in a reduction in the number of malfunctioning intermittent controllers and thus reduce emissions. The average emission factor for intermittent vent pneumatic controllers represents the average emission rates of all controllers tested, including properly functioning and malfunctioning controllers.

Table 6-15. Natural Gas-Driven Pneumatic Controller Emission Factors for Intermittent Vent Controllers in Production

Controller Type	Original Units, Emission Factor [a] (scf whole gas/ controller-hr)	Uncertainty (±%)	Methane Emission Factor [b] (Converted) (scf CH_4/ controller-hr)	Methane Content Basis of Factor [b] (mole %)	Methane Emission Factor [b] (Converted to tonnes basis) (tonnes CH_4/ controller-yr)
API Study Emission Factors[a]					
Intermittent, average [c]	9.3	Not specified	7.6	81.6	1.27
Intermittent, normal operation [d]	0.28		0.23	81.6	0.038
Intermittent, malfunctioning operation [e]	24.1		19.7	81.6	3.30
EPA GHGRP Subpart W Emission Factors[f]					
Intermittent	13.5	Not specified	11.0	81.6	1.85

Footnotes and Sources:

[a] API working paper, *Pneumatic Controller Inventory and Measurement at 67 Oil and Gas Sites in the Western United States*, 2020.

[b] Conversion from whole gas to methane was calculated assuming 81.6 mole % CH_4 in the gas, according to the GHGI methane content for natural gas (EPA, 2019b). Conversion to annual basis assumes 8,760 hrs/yr operation rather than solely using the controller venting hours since emission factors are based on a time averaging of actuation and non-actuation periods.

[c] The average emission factor should be used for controllers that are not routinely monitored as part of a proactive monitoring and repair program.

[d] The normal operation emission factor should be applied to controllers that are found to be operating normally as part of a proactive monitoring and repair program.

[e] The malfunctioning operation emission factor should be applied to controllers that are found to be venting at a higher than expected rate, as discovered from a proactive monitoring and repair program.

[f] EPA GHGRP Subpart W Table W-1A. (EPA, 2019a).

Many operators are beginning to monitor intermittent controllers to confirm the controller is operating normally or malfunctioning and venting at a higher rate than expected for a properly operated controller. Based on the implementation status of a pneumatic controller monitoring and repair program, the emission factors in Table 6-15 should be applied to intermittent vent pneumatic controllers as follows:

- Operations with a proactive monitoring and repair program for pneumatic controllers:
    - Use the normal operation emission factor for controllers that are found to be operating properly as part of a routine monitoring program.
    - Use the malfunctioning operation emission factor for controllers found to be improperly operating as part of a routine monitoring program. The malfunctioning operation emission factor would be applied for the period prior to a confirmed repair, akin to leak/no-leak factors applied to fugitive components (EPA, 1995b).

- Operations without a proactive monitoring and repair program for pneumatic controllers:
  - Use the average emission factor for all intermittent vent pneumatic controllers.
  - Note that for emission reductions from pneumatic controllers to be quantified using emission factors, a routine monitoring and repair program is necessary to demonstrate that controllers are operating normally.

For controllers that are part of a monitoring and repair program, the total CH_4 emissions may be estimated based on the amount of time the controller was operating normally or malfunctioning using the repair date information collected in a monitoring program. This approach is similar to a leak detection and repair (LDAR) program for fugitives using leak/no-leak emission factors, as described in GHGRP (Equation W-30), and shown in Equation 6-14 below.

$$E_x = \left(n_{normal} \times EF_{normal} \times T_{normal}\right) + \left(n_{mf} \times EF_{mf} \times T_{mf}\right) \qquad \text{(Equation 6-14)}$$

where:

E_x = Emissions of “x” in units of mass (pounds, kg, tonnes) per year;
“x” = GHG compound of interest (CH_4, or CO_2 for CO_2 rich streams);
n_{normal} = Number of intermittent vent pneumatic controllers in normal operation;
EF_{normal} = GHG emission factor for intermittent vent pneumatic controller in normal operation (tonnes CH_4/controller-yr);
T_{normal} = Fraction of the year when intermittent vent pneumatic controller is in normal operation;
n_{mf} = Number of intermittent vent pneumatic controllers in malfunctioning operation;
EF_{mf} = GHG emission factor for intermittent vent pneumatic controller in malfunctioning operation (tonnes CH_4/controller-yr); and
T_{mf} = Fraction of the year when intermittent vent pneumatic controller is in malfunctioning operation.

An example calculation is provided below in Exhibit 6-12 that demonstrates the use of the pneumatic controller emission factors.

EXHIBIT 6-12: Sample Calculation for Gas-Driven Intermittent Vent Pneumatic Controller Emissions

INPUT DATA:
A gas production facility has 80 natural gas-driven intermittent vent pneumatic controllers. The facility has implemented a routine monitoring and repair program that includes surveys of these controllers. In the present year, a monitoring survey was conducted and repairs made that resulted in the following data:

Operating Category	Number of Controllers Screened by Operating Category	Repair Date	Fraction of Year in Normal Operating Category	Fraction of Year in Malfunctioning Operating Category
Normally Operating	76	NA	1.0	0
Malfunctioning	4	March 31	9/12 months = 0.75	3/12 months = 0.25

The average CH_4 content of the gas is 70 mole %. There is also 9 mole % CO_2 in the gas, so CO_2 emissions from the pneumatic controllers are also estimated. Calculate the CH_4 and CO_2 emissions.

CALCULATION METHODOLOGY:
Because the facility has implemented a routine monitoring and repair program that includes pneumatic controllers, the emission factors from Table 6-15 for normal and malfunctioning controllers are used. Emissions are calculated by multiplying the number of intermittent pneumatic controllers screened and reported by operating category by the appropriate emission factor from Table 6-15. Equation 6-13 is used to calculate the annual total emissions using the fraction of the year in each operating category.

The base pneumatic controller CH_4 emission factor is also adjusted from the default basis provided in Table 6-15 of 81.6 mole % CH_4 to the site-specific basis of 70 mole % CH_4. Because the gas contains a significant quantity of CO_2, emissions of CO_2 are also estimated using the whole gas emission factor and relative CO_2 and CH_4 contents in the gas.

$$E_{CH_4} = \left[\left(\frac{0.038\text{ t CH}_4}{\text{controller-yr}} \times [(76\text{ controllers} \times 1.0) + (4\text{ controllers} \times 0.75)]\right)\right] + \left(\frac{3.30\text{ t CH}_4}{\text{controller-yr}} \times (4\text{ controllers} \times 0.25)\right) \times \frac{0.70\text{ mole \% CH}_4}{0.816\text{ mole \% CH}_4}$$

$\underline{E_{CH_4} = 5.41\text{ tonnes CH}_4\text{/yr}}$

$$E_{CO_2} = \frac{5.41\text{ tonnes CH}_4}{\text{yr}} \times \frac{\text{tonne mole CH}_4}{16\text{ tonne CH}_4} \times \frac{\text{tonne mole gas}}{0.70\text{ tonne mole CH}_4} \times \frac{0.09\text{ tonne mole} CO_2}{\text{tonne mole gas}} \times \frac{44\text{ tonne CO}_2}{\text{tonne mole CO}_2}$$

$\underline{E_{CO_2} = 1.91\text{ tonnes CO}_2\text{/yr}}$

Pneumatic Controllers (When Type is Unknown)

When the type of pneumatic controllers installed is not known, average default emission factors may be used to quantify the CH_4 emissions from natural gas-operated controllers. The table below presents an overall average CH_4 emission factor for a pneumatic controller in the production segment that can be applied when the type of controller is unknown.

9.2 scf whole gas/hr/controller (Original Units) [a, b]
7.5 scf CH_4/controller-hr (Converted) [c]
1.26 tonnes CH_4/controller-yr (Converted) [c.d]

Footnotes and Sources:

[a] API working paper, *Pneumatic Controller Inventory and Measurement at 67 Oil and Gas Sites in the Western United States*, 2020.

[b] Uncertainty is not specified for this value.

[c] The original whole gas emission factor was converted to whole gas assuming 81.6 mole % CH_4 in natural gas, according to GHGI (EPA, 2019b). The CH_4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH_4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

[d] Conversion to annual basis assumes 8,760 hrs/yr operation.

6.3.7 Gas Driven Pneumatic Pumps

Natural gas-driven chemical injection pumps (CIPs) are a source of CH_4 emissions due to venting of the gas used to act on a piston or diaphragm to pump chemicals into the process equipment lines. The CIPs can also be a source of CO_2 emissions if the gas used to drive the pump contains a significant amount of CO_2.

If fuel gas is used as the pneumatic gas and is taken downstream of the total fuel gas meter, then the vented gas volume must be subtracted from the total fuel gas volume (used to determine combustion emissions).

The 1996 GRI/EPA study observed that gas-powered chemical injection pumps are most commonly found in the production segment where electricity may not be readily available (Shires, 1996). Typical chemicals injected into the process lines include biocides, demulsifiers, clarifiers, corrosion inhibitors, scale inhibitors, hydrate inhibitors, paraffin dewaxers, surfactants, oxygen scavengers, and H_2S scavengers.

The most rigorous approach for estimating GHG emissions from CIPs is to use site-specific gas usage measurements or manufacturer data. Another rigorous approach is to calculate the volume of natural gas emitted from the volume of liquid pumped. The volume of natural gas emissions from a pneumatic pump is a function of the amount of liquid pumped (displacement volume), the liquid outlet pressure from the pump, the gas pressure and temperature used as the pneumatic power gas, and the “mechanical efficiency loss” across the pump. In manufacturers information this relationship is typically described using a set of “pump curves.” However it can be described mathematically using Equation 6-15.

$$V_G = \left(\frac{P_O + P_A}{14.7}\right) \times \left(\frac{T_A}{459.7 + T_G}\right) \times V_L \times [1 + I] \qquad \text{(Equation 6-15)}$$

where:

V_G = Gas loss from natural gas driven pneumatic pump, scf/yr;
P_O = Outlet pressure from the pump, psig;

P_A = Atmospheric pressure, psig;
14.7 = Atmospheric pressure, psig;
T_A = Atmospheric temperature, °R;
459.7 = Conversion from °F to °R;
T_G = Gas temperature, °F;
V_L = Volume of liquid pumped, ft^3/yr, from measurement data or calculated using Equation 6-16; and
(1 + I) = Manufacturer-specific pump inefficiency, or assumed default of 30%.

The volume of liquid pumped in Equation 6-15 can be calculated as shown in Equation 6-16.

$$V_L = \frac{V_S}{7.48} \times N \times T \qquad \text{(Equation 6-16)}$$

where:

V_S = Volume of liquid pumped per stroke, gal/stroke;
7.48 = Conversion from gal to scf;
N = Number of strokes/min; and
T = Annual operational time, min/year.

After calculating the volume of gas loss, CH_4 and CO_2 emissions can then be calculated using the CH_4 and CO_2 content of the gas, such as described in Equation 6-2.

Alternatively, the simplified emission factors in Table 6-16 can be used to estimate CH_4 emissions from gas-driven CIPs. The factors are given for piston and diaphragm type pumps, and an average emission factor is given if the type of pump is unknown.

Table 6-16. Gas-Driven Chemical Injection Pump CH_4 Emission Factors

Type of Chemical Injection Pump	Emission Factor, Original Units	Uncertainty [a] (±%)	Methane Emission Factor (Converted) [b] (tonnes CH_4/pump-yr)	Methane Content Basis of Factor [b] (mole %)	Whole Gas Emission Factor (Converted) [b, c] (scf gas/pump-hr)
Piston pumps	48.9 scfd CH_4/pump [d]	141 [e]	0.34	78.8	2.59
	2.03 scf gas/hr/pump [f]	Not specified	0.28	81.6	2.03
	0.5917 m^3 gas/hr/pump [g]	Not specified	2.86	81.6	20.9
Diaphragm pumps	446 scfd CH_4/pump [d]	99 [e]	3.12	78.8	23.6
	18.58 scf gas/hr/pump [f]	Not specified	2.54	81.6	18.6

Type of Chemical Injection Pump	Emission Factor, Original Units	Uncertainty[a] (±%)	Methane Emission Factor (Converted)[b] (tonnes CH_4/ pump-yr)	Methane Content Basis of Factor[b] (mole %)	Whole Gas Emission Factor (Converted)[b, c] (scf gas/pump-hr)
	1.0542 m^3 gas/hr/pump[g]	Not specified	5.11	81.6	37.3
Average pump (if type not known)	248 scfd CH_4/pump[d]	108[e]	1.73	78.8	13.1
	101,000 scf CH_4/yr/pump[h]	44	1.93	81.6	14.1
	0.9726 m^3 gas/hr/pump[i]	14	4.71	81.6	34.4

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval.

[b] Whole gas emission factors converted to CH_4 emission factors assuming 81.6 mole % CH_4 in the gas, unless otherwise indicated, according to the GHGI methane content for natural gas (EPA, 2019b). Whole gas emissioon factors converted from m^3 are based on 15°C and 1 atm.

[c] CH_4 emission factors converted to whole gas are calculated using methane content basis of factor shown.

[d] 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.

[e] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[f] Climate and Clean Air Coalition (CCAC) O&G Methane Partnership, *Technical Guidance Document Number 1: Natural Gas Driven Pneumatic Controllers and Pumps,* March 2017.

[g] Prasino Group, *Determining bleed rates for pneumatic instruments in British Columbia*, Dec. 18, 2013.

[h] Allen et al, *Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers*, 2014.

[i] Clearstone Engineering and Carlton University, *Update of Equipment, Component and Fugitive Emission Factors for Alberta Upstream Oil and Gas*, prepared for Alberta Energy Regulator, 2018.

The emission factors are taken from the following sources: the 1996 GRI/EPA report (Volume 13) (Shires, 1996), the 2017 CCAC Technical Guidance Document Number 1: Natural Gas Driven Pneumatic Controllers and Pumps (CCAC, 2017), 2013 study in British Columbia (Prasino Group, 2013), and 2014 University of Texas study (Allen, 2014). These emission factors for piston and diaphragm pumps represent both US and Canadian data sources and measurement programs.

The CIP emission factors in Table 6-16 above include the volumetric emissions in whole gas per hour per controller as well as tonnes CH_4 per year per controller. Values that were originally presented in scf CH_4 per time per controller were converted to whole gas assuming 81.6 mole % CH_4 composition, from the GHGI (EPA, 2019b). The methane emission factors should be adjusted for site specific operating parameters using gas composition, if the natural gas has a significantly different CH_4 content from the default basis. Also, if the pumps are driven with gas that contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions. (An example of emission factor adjustment for different compositions of CH_4 and CO_2 are provided in Exhibit 6-12 for intermittent vent pneumatic controllers.)

6.3.8 Gas Treatment Processes

6.3.8.1 Glycol Dehydration

Glycol dehydrators are used to remove water from gas streams by contacting the gas with a liquid glycol stream in an absorber. The liquid glycol absorbs the water from the gas stream, and the water is driven from the rich[7] glycol by heating the glycol in the reboiler (or regenerator). A small amount of CH_4 is absorbed by the glycol and driven off to the atmosphere in the glycol regeneration step. A stripping gas may also be introduced into the regenerator to help strip water and other absorbed compounds out of the glycol. Methane emissions from uncontrolled glycol dehydration units occur because the CH_4 removed from the glycol stream passes directly through the regenerator and is vented to the atmosphere.

Some glycol dehydration systems also have a glycol flash tank separator prior to the rich glycol stream being routed to the regenerator. If a glycol flash separator is present in the process configuration, some of the absorbed CH_4 in the rich glycol stream is flashed off in the flash tank separator. The resulting flash gas may be combusted in the glycol regenerator reboiler, the fuel gas stream, or a flare; or the flash gas may be routed to the regenerator as stripping gas. If applicable, appropriate accounting for the CH_4 in the flash gas is needed to avoid double counting CH_4 emissions in the glycol dehydration regenerator overhead stream.

The pump used to circulate glycol in a glycol dehydration process may also have an impact on CH_4 emissions. Some glycol dehydration systems are configured with a natural gas-assisted pump to circulate glycol and must be accounted for in quantifying CH_4 emissions, if applicable.

Note that combustion emissions from the glycol reboiler are not included in this section, and should be estimated using the combustion techniques presented in Section 4. Similarly, dehydration vents routed to a flare or other combustion control device should be estimated using the techniques presented in Section 5.

Figure 6-1 illustrates the methods available for estimating CH_4 emissions from glycol dehydrators, starting with using test data. However, such test data may not be available. If detailed information about the site-specific glycol dehydrator unit is known, a process simulator or other computer software such as GRI-GLYCalc™ (GRI, 2000) can be used to estimate the emissions. Detailed information needed to run the GRI-GLYCalc™ computer simulation includes: wet gas hydrocarbon composition, wet gas flow rate, wet gas temperature and pressure, existence of a gas-driven glycol pump, wet and dry gas water contents, glycol flow rate, use of stripping gas flowrate to the regenerator, and the temperature and pressure of the flash tank, if present.

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[7] Rich glycol stream refers to the water laden glycol stream after passing through the gas contactor, prior to water removal in the regenerator.

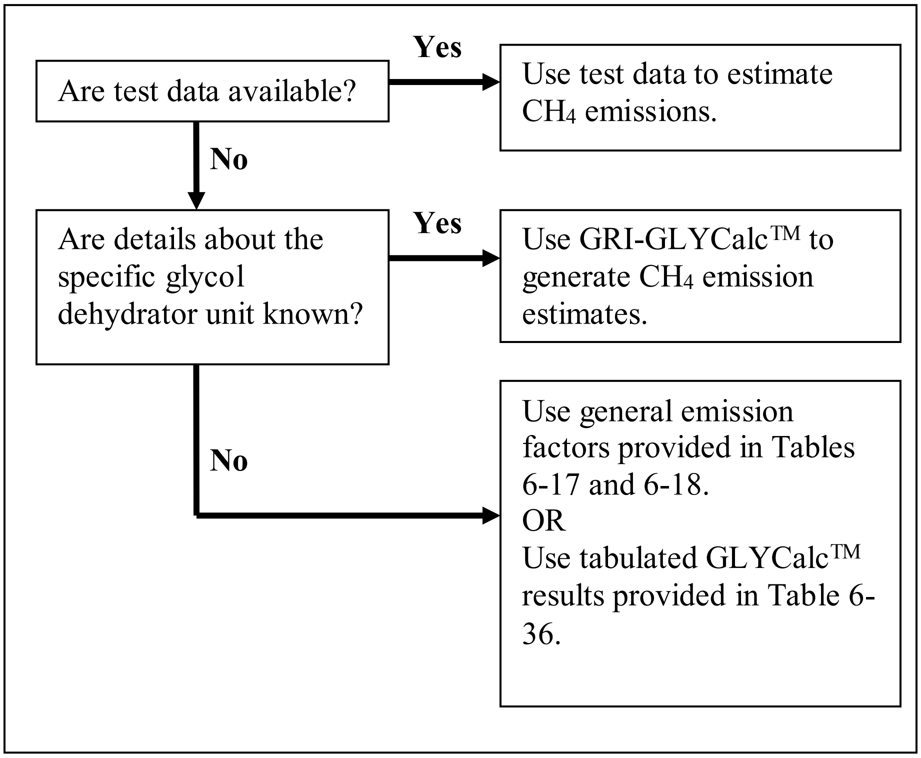

Figure 6-1. Methane Emissions from Glycol Dehydrators

As shown, test data or simulation software, such GRI-GLYCalc™, are the preferred approaches if site-specific data are available. If this process-specific information is not readily available, simplified emission factors can be used. The emission factors provided in Table 6-17 on a gas processed basis, for a glycol dehydrator without a gas-assisted glycol pump, were developed using both site data and computer simulations (Myers, et al, 1996). The emission factor on a dehydrator population count basis are from GHGRP Subpart W for glycol dehydrators at a well site.

Table 6-17. Production Segment Uncontrolled Gas Dehydration Methane Emission Factors

Excludes Glycol Gas-Assisted Pump Emissions – See Table 6-18

Emission Factor, Original Units	Uncertainty [a] (+/- %)	Methane Emission Factor [b], Converted to Tonnes Basis	Methane Content Basis of Factor [c] (mole %)	Whole Gas Emission Factor (Converted) [d]
275.57 scf $CH_4/10^6$ scf gas processed [c]	191	0.0052859 tonnes $CH_4/10^6$ scf gas processed	78.8	349.7 scf gas/10^6 scf gas processed
		0.18667 tonnes $CH_4/10^6$ sm^3 gas processed		349.7 sm^3 gas/10^6 sm^3 gas processed
73.4 Mscf CH_4/ dehydrator-yr [e]	Not specified	0.06149 tonnes CH_4/ dehydrator-yr		93.2 Mscf CH_4/ dehydrator-yr

Footnotes and Sources:

[a] Uncertainty is based on a 95% confidence interval; however, because the data used to calculate the reference emission factor were unavailable, the uncertainty at a 95% confidence interval was calculated based on the uncertainty at a 90% confidence interval presented in the source, assuming a data set size of 10.

[b] CH_4 emission factors converted from scf are based on 60°F and 14.7 psia.

[c] Myers, D.B. *Methane Emissions from the Natural Gas Industry, Volume 14: Glycol Dehydrators, Final Report*, GRI-94/0257.31 and EPA-600/R-96-080n, Gas Research Institute and U.S. Environmental Protection Agency, June 1996. Emission factor was derived assuming 78.8 mole % CH_4 in the wet processed gas stream.

[d] Converted using 78.8 mole % CH_4 assumed in the derivation of the CH_4 emission factor.

[e] US EPA, 40 CFR 98.233(e)(2), Subpart W, Equation W-5 (EPA, 2019a).

The emission factors in Table 6-17 can be scaled based on the ratio of the site-specific CH_4 content to the default emission factor concentration if the site natural gas has a significantly different CH_4 content from the default basis of 78.8 mole %. However, if process-specific data is available, it is preferable to use a process simulator to quantify emissions at a significantly different CH_4 content, since emissions are dependent on the solubility characteristics of CH_4 in glycol at the process conditions in the contactor, which may not be directly proportional to the ratio of CH_4 concentrations in the treated wet gas stream. Note that CO_2 is not appreciably soluble in glycol; therefore, CO_2 emissions are expected to be negligible, even if the gas contains significant quantities of CO_2. Exhibit 6-13 demonstrates these calculations.

EXHIBIT 6-13: Sample Calculation for Dehydration Processing Vent Emissions

INPUT DATA:

A glycol dehydrator at a gas production facility treats 25 x 10^6 scf/day of gas with a CH_4 molar content of 82 mole % and CO_2 content of 5 mole %. The dehydration unit includes an electric pump and does not include a flash separator. The glycol circulation rate is 200 gallons/hr, and the contactor pressure is 600 psig. Stripping gas is not used in the process. Calculate the CH_4 and CO_2 emissions.

CALCULATION METHODOLOGY:

1. *Calculate the CH_4 emissions.* Emissions would ideally be estimated using a process simulator; however, here they are calculated using an emission factor taken from Table 6-17. Because the CH_4 content of this facility differs from the 78.8 mole % default CH_4 content associated with the emission factor presented in Table 6-17, the calculations include an adjustment for the composition:

$$E_{CH_4}=\frac{25\times10^6\ \text{scf}}{\text{day}}\times\frac{365\ \text{day}}{\text{yr}}\times\frac{0.0052859\ \text{tonne CH}_4}{10^6\ \text{scf}}\times\frac{0.82\ \text{tonne mole CH}_4\ \text{(facility)}}{0.788\ \text{tonne mole CH}_4\ \text{(default)}}$$

$$\underline{E_{CH_4}=50.2\ \text{tonnes CH}_4/\text{yr}}$$

CO_2 emissions from the glycol dehydrator are negligible because CO_2 is not appreciably soluble in glycol.

Note that the emission factors given in Table 6-17 do not include the emissions from gas-assisted glycol pumps, which can be a significant source of CH_4 emissions. Although the CH_4 from gas-assisted pumps are emitted through the regenerator vent, the emission rates were developed as a separate emission source in the GRI/EPA CH_4 emissions study, and are discussed below (Myers et al, 1996; Harrison et al., 1996).

Some glycol dehydrators use flash tanks, also referred to as flash separators. Flash tanks are used to drop the glycol line pressure, causing most of the light hydrocarbons in the glycol to flash into the vapor phase. If left uncontrolled, vapors from the flash tank can be a significant source of CH_4 emissions. However, flash gas is most often routed to the regenerator burner as fuel, significantly reducing CH_4 emissions from the regenerator vent. The uncontrolled emission factors presented in Table 6-17 would overestimate emissions from a glycol dehydration system with a flash tank separator that routes the flash gas to a vapor recovery system. Emission factors that reflect the use of flash separators are discussed below.

Some dehydrators also introduce stripping gas in the regenerator to help strip water and other absorbed compounds out of the glycol by increasing the vapor flow rate in the reboiler still. Three types of stripping gas are typically used: dry natural gas from the absorber, flash gas from the flash separator, or nitrogen. Any CH_4 in the stripping gas will pass directly through the regenerator; therefore, the use of dry natural gas will increase CH_4 emissions from the regenerator. GLYCalc™ should be used to estimate CH_4 emissions in this situation, as the default approaches presented in this subsection do not account for the use of stripping gas. The emission factors presented in Tables 6-17 or 6-18 may be used to estimate emissions from the dehydrator if flash gas or nitrogen is used as the stripping gas, as CH_4 emissions will not be increased.

Glycol Pumps

As demonstrated by the GRI/EPA study, gas-assisted glycol pumps can be a significant source of CH_4 emissions (Myers et al, 1996). Both electric and gas-assisted pumps are used to circulate glycol in the dehydrator system. If a gas-assisted pump is used, the low-pressure glycol is pumped into the absorber by pistons driven by the high-pressure glycol leaving the absorber. This high pressure glycol contains some entrained gas from the absorber. The GRI/EPA CH_4 emissions project estimated the gas-assisted glycol pump emissions separately from the dehydrator vent emissions, although they are emitted from the same vent.

The GRI/EPA study noted that Kimray was a leading manufacturer of gas-assisted glycol pumps. Emission factors were presented in this study (Volume 15) based on technical data from Kimray and using assumptions about typical dehydrator operation (Myers et al, 1996). Production Kimray pump CH_4 emissions are given in Table 6-18. This table also includes the default CH_4 content that can be used for adjusting the emission factors to other CH_4 contents.

Table 6-18. GRI/EPA Kimray Pump Methane Emission Factors

Industry Segment	Methane Emission Factor [a], Original Units	Uncertainty [c] (+/- %)	Methane Emission Factor [b], Converted to Tonnes Basis	Methane Content Basis of Factor (mole %)	Whole Gas Emission Factor [d], Converted to Whole Gas Volume Basis
Production	992.0 scf $CH_4/10^6$ scf gas processed	82.8	0.01903 tonnes $CH_4/10^6$ scf gas processed	78.8	1258 scf gas/10^6 scf gas processed
		61.5	0.6720 tonnes $CH_4/10^6$ sm^3 gas processed		1258 sm^3 gas/10^6 sm^3 gas processed

Footnotes and Sources:

[a] Myers, D.B. and M.R. Harrison. *Methane Emissions from the Natural Gas Industry, Volume 15: Gas Assisted Glycol Pumps*, Final Report, GRI-94/0257.33 and EPA-600/R-96-080o, Gas Research Institute and U.S. Environmental Protection Agency, June 1996. Emission factor was derived assuming 78.8 mole % CH_4 in the wet processed gas stream.

[b] CH_4 emission factors converted from scfy are based on 60°F and 14.7 psia.

[c] Uncertainty is based on a 95% confidence interval; however, because the data used to calculate the reference emission factor were unavailable, the uncertainty at a 95% confidence interval was calculated based on the uncertainty at a 90% confidence interval presented in the source assuming a data set size of 10.

[d] Converted using 78.8 mole % CH_4 assumed in the derivation of the CH_4 emission factor.

An example calculation for glycol dehydrator Kimray pump CH_4 emissions is given below.

EXHIBIT 6-14: Sample Calculation for Dehydration Kimray Vent Emissions

INPUT DATA:

A glycol dehydrator in a production facility treats 25×10^6 scf/day of gas with a CH_4 molar content of 82 mole % and CO_2 content of 5 mole %. This dehydration unit includes a gas-operated pump but does not include a flash separator. Calculate the vented emissions from the pump.

CALCULATION METHODOLOGY:

Assuming the pump is a Kimray or similar type,
Table 6-18 provides an appropriate emission factor. The CH_4 emissions are calculated by multiplying this emission factor by the annual gas throughput and adjusting for the facility CH_4 concentration, as shown below.

$$E_{CH_4,\text{ pump}} = \frac{25\times10^6 \text{ scf}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{0.01903 \text{ tonne } CH_4}{10^6 \text{ scf}} \times \frac{0.82 \text{ tonne mole } CH_4 \text{ (facility)}}{0.788 \text{ tonne mole } CH_4 \text{ (default)}}$$

$$\underline{E_{CH_4,\text{ pump}} = 180.7 \text{ tonnes } CH_4/\text{yr}}$$

CO_2 emissions are calculated by correcting the CH_4 emissions by the ratio of CH_4 to CO_2 in the facility gas.

$$E_{CO_2,\text{ pump}} = 180.7 \text{ tonnes } CH_4 \times \frac{\text{tonne mole } CH_4}{16 \text{ tonne } CH_4} \times \frac{\text{tonne mole gas}}{0.82 \text{ tonne mole } CH_4} \times \frac{0.05 \text{ tonne mole } CO_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne } CO_2}{\text{tonne mole } CO_2}$$

$$\underline{E_{CO_2,\text{ pump}} = 30.3 \text{ tonnes } CO_2/\text{yr}}$$

6.3.8.2 Desiccant Dehydration

Desiccant dehydrators have lower CH_4 (and CO_2) emissions compared to glycol-based systems. Desiccant systems remove the moisture in the gas by passing the wet gas through a drying bed of desiccant tablets (e.g., salts such as calcium, potassium, or lithium chlorides). Molecular sieves can also be used as the desiccant in these systems. Molecular sieves selectively adsorb acid gas molecules of smaller diameter than methane, and can be used for both gas dehydration and acid gas treatment.

Portable desiccant dehydrators can also be used during maintenance activities when the glycol dehydrator that is normally used has to be shut down. For example, low pressure wells may be vented to the atmosphere during maintenance activities because it can be difficult to resume flow if the wells are shut in (EPA, 2004b). However, the portable desiccant system can be used in place of the glycol dehydrator system, thus avoiding having to vent the low pressure well to the atmosphere.

Since the desiccant dehydrator systems are fully enclosed, emissions only occur when the vessel is opened to change out the desiccant tablets. The emissions from these desiccant dehydrators can be estimated based on the internal volume of the dehydrator, as shown in the following:

$$\mathrm{GLD} = \frac{\mathrm{H} \times \mathrm{D}^2 \times \pi \times \mathrm{P}_2 \times \mathrm{G} \times \mathrm{N}}{4 \times \mathrm{P}_1} \qquad \text{(Equation 6-17)}$$

where:

GLD = Gas loss from desiccant dehydrator, scf/yr;
H = Dehydrator vessel height, ft;
D = Dehydrator vessel inside diameter, ft;
P_2 = Gas pressure, psia;
P_1 = Atmospheric pressure, 14.7 psia;
G = Fraction of packed vessel volume that is gas; and
N = Number of desiccant change outs per year.

An example calculation for desiccant dehydrator emissions is shown in Exhibit 6-15. The example is based on Exhibit 12 presented in the November 2003 EPA Gas STAR Lessons Learned document, *Replacing Glycol Dehydrators with Desiccant Dehydrators* (EPA, 2003c).

EXHIBIT 6-15: Sample Calculation for Desiccant Dehydration Venting

INPUT DATA:

A desiccant dehydrator at a gas processing plant has a vessel height of 6.40 feet and an inside diameter of 1.60 feet. The pressure of the gas inside the vessel is 450 psig (464.7 psia). The desiccant material is refilled 52 times annually. The vessel is assumed to be 45% packed. The CH_4 and CO_2 molar contents are 90% and 5%, respectively. Calculate the CH_4 and CO_2 emissions.

CALCULATION METHODOLOGY:

The gas vented from the desiccant dehydrator vessel is estimated using Equation 6-16.

$$\text{GLD} = \frac{(6.40\ \text{ft}) \times (1.60\ \text{ft})^2 \times (3.1416) \times (464.7\ \text{psia}) \times (0.45) \times 52}{4 \times (14.7\ \text{psia})}$$

$$\underline{\text{GLD} = 9{,}519\ \text{scf/yr (total gas)}}$$

The CH_4 and CO_2 emissions are then estimated using the gas molar contents:

$$E_{CH_4} = \frac{9{,}519\ \text{scf}}{\text{yr}} \times \frac{0.90\ \text{scf}\ CH_4}{\text{scf gas}} \times \frac{\text{lbmole}\ CH_4}{379.3\ \text{scf}\ CH_4} \times \frac{16\ \text{lb}\ CH_4}{\text{lbmole}\ CH_4} \times \frac{\text{tonnes}}{2204.62\ \text{lb}}$$

$$\underline{E_{CH_4} = 0.16\ \text{tonnes}\ CH_4/\text{year}}$$

$$E_{CO_2} = \frac{9{,}519\ \text{scf}}{\text{yr}} \times \frac{0.05\ \text{scf}\ CO_2}{\text{scf gas}} \times \frac{\text{lbmole}\ CO_2}{379.3\ \text{scf}\ CO_2} \times \frac{44\ \text{lb}\ CO_2}{\text{lbmole}\ CO_2} \times \frac{\text{tonnes}}{2204.62\ \text{lb}}$$

$$\underline{E_{CO_2} = 0.025\ \text{tonnes}\ CO_2/\text{yr}}$$

6.3.8.3 Other Gas Dehydration Alternatives

Methods of reducing CH_4 emissions range from operational alterations to technological alternatives. Operational alterations, such as optimizing glycol circulation rates or installing electric pumps, have been shown to reduce, but not eliminate, CH_4 emissions. Technological alternatives include replacing glycol dehydrators with desiccant dehydrators (discussed in Section 6.3.8.2), separators, and in-line heaters, or methanol injection units.

The use of separators and in-line heaters for water removal is a two-step process. First, the gas is expanded in a cyclone. This expansion lowers the temperature of the gas, enhancing water condensation and separation. Then the gas is reheated to restore it to a dew point below conditions in the pipeline system. Vented emissions from the separator should be calculated using an engineering approach. Combustion emissions from the line heater should be calculated using the methodology described in Section 4.

Methanol injection units are an efficient method for controlling gas hydrate formation in the lines. While methanol may absorb some of the water in the gas, its primary function is to act as a hydrate inhibitor. Methanol injection lowers the temperature at which hydrates can form, thereby reducing gas hydrate formation. Unlike glycol dehydration, methanol injection requires no regeneration, thus eliminating vented emissions.

6.3.8.4 Acid Gas Removal/Sulfur Recovery Units

Natural gas with high concentrations of acid gas species (H_2S and CO_2), referred to as sour gas, must be treated to reduce the acid gases to a concentration that meets pipeline corrosion-prevention specifications. Acid Gas Removal (AGR) units remove H_2S and CO_2 by contacting the sour gas with a liquid solution (typically amines). AGR units have similar equipment to those in the dehydrator units (an absorber, liquid circulation pump, and a reboiler to regenerate the absorber liquid).

Sulfur Recovery Units (SRUs) can also be used to recover elemental sulfur from H_2S. A byproduct of natural gas processing or crude oil refining, H_2S is converted to elemental sulfur through the use of a recovery process. The most common process is the Claus process, in which the H_2S undergoes catalytic oxidation in a two-step process. The Claus process consists of a thermal process and a catalytic process, both of which form elemental sulfur through the conversion of H_2S to sulfur and water. During the oxidation process, side reactions occur then produce other compounds including CO_2.

Methane Emissions

The amine solution associated with AGR units can absorb a small amount of CH_4 from the gas, and some CH_4 can be driven off to the atmosphere from the reboiler vent. In closed amine systems, the reboiler vent is directed to the facility flare and no methane venting occurs. Figure 6-2 shows the approaches available to estimate CH_4 emissions from AGR units, which are dictated by whether specific information is known about the sour gas, such as temperature and pressure.

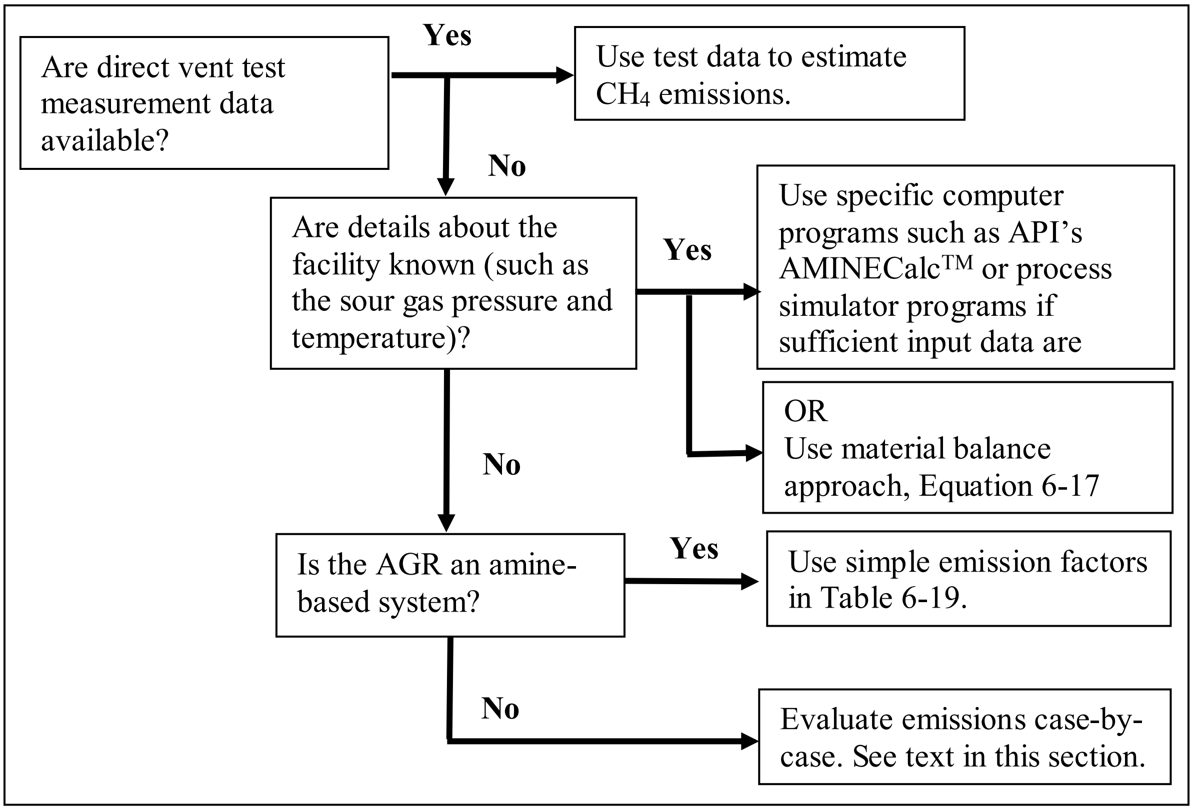

Figure 6-2. CH_4 Emissions from Acid Gas Removal (AGR) Units

As shown, measurement data of use of simulation software to estimate CH_4 emissions from AGR units is the preferred approach when site-specific data is available. API's AMINECalc™ can be used to estimate CH_4 for amine units. Details on this software are available at the following API web address by searching for API Publication Number 4679: *http://www.api.org/* (API, 1999).

Emissions from AGR unit vents routed to a flare or other control device should be estimated using the techniques presented in Section 5.

In the absence of site-specific data, default emission factors can be used for quantifying CH4 emissions. For uncontrolled AGR units, two CH_4 emission factors for AGR vents were developed as part of the 1996 GRI/EPA CH_4 emissions study (Volume 14, page A-13) based on process simulation results for typical unit operations of a diethanol amine (DEA) unit (Myers, 1996). Table 6-19 provides the AGR CH_4 emission factor on both a throughput basis and unit basis. The throughput basis should be used over the unit basis factor if the volume of treated gas is known.

Table 6-19. Uncontrolled AGR Methane Emission Factor

Source	Methane Emission Factor, Original Units	Methane Emission Factor [a], Converted to Tonnes Basis	Uncertainty [b] (+/- %)
AGR vent	965 scf $CH_4/10^6$ scf treated gas [c]	0.0185 tonnes $CH_4/10^6$ scf treated gas 0.654 tonnes $CH_4/10^6$ Sm^3 treated gas	119
	33,794 scfd CH_4/AGR unit [c]	0.6482 tonnes CH_4/day-AGR unit	125

Footnotes and Sources:

[a] CH_4 emission factors converted from scf are based on 60°F and 14.7 psia.

[b] Uncertainty is based on a 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[c] Myers, D.B. *Methane Emissions from the Natural Gas Industry, Volume 14: Glycol Dehydrators, Final Report*, GRI-94/0257.31 and EPA-600/R-96-080n, Gas Research Institute and U.S. Environmental Protection Agency, June 1996. Based on a diethanolamine (DEA) unit.

There are other acid gas removal technologies besides amine units, including the Morphysorb® process, Kvaerner Membrane technology, and the Molecular Gate® process, the latter of which involves the use of molecular sieves. These technologies are reported to reduce CH_4 emissions, although published emission factors are not available (EPA, 2007a).

An example calculation for AGR CH_4 emissions is given in Exhibit 6-16, based on the emission factors in Table 6-19.

EXHIBIT 6-16: Sample Calculation for AGR Vent Emissions

INPUT DATA:

A production facility has one amine-based AGR unit that vents to atmosphere. The treated gas throughput of the AGR unit is not known. The facility operates continuously throughout the year (8,760 hours/year). Calculate the CH_4 emissions.

CALCULATION METHODOLOGY:

The AGR unit-based CH_4 emission factor from Table 6-19 is multiplied by the number of AGR units and converted from a daily basis to an annual basis.

$$E_{CH_4} = (1\ \text{AGR}) \times \frac{0.6482\ \text{tonne CH}_4}{\text{day-AGR}} \times \frac{365\ \text{day}}{\text{yr}}$$

$$\underline{E_{CH_4} = 236.6\ \text{tonnes CH}_4/\text{yr}}$$

Note that the treated gas throughput-based CH_4 emission factor could have been used instead of the unit-based factor if the AGR throughput data had been available.

Carbon Dioxide Emissions

Sour gas processing by acid gas removal or sulfur recovery units can directly vent the CO_2 removed from the sour gas stream to the atmosphere or capture the CO_2 for other uses, such as enhanced oil recovery. For systems that vent the waste CO_2 (for example, amine unit regenerator vents), emissions can be estimated by material balance using the known throughput and CO_2 concentrations of the inlet and outlet gas streams as shown in the following equation (CAPP, 2003).

$$E_{CO_2} = \left[\left(\frac{\text{Volume}}{\text{time}} \times CO_2\ \text{mole\%}\right)_{\text{sour}} - \left(\frac{\text{Volume}}{\text{time}} \times CO_2\ \text{mole\%}\right)_{\text{sweet}}\right] \times \frac{44}{\text{molar volume conversion}}$$

(Equation 6-18)

where:

E_{CO_2} = Mass emissions of CO_2 per year (in pounds or kg);

Volume = Volume of the sour and sweet gas (in scf or Sm^3 at STP conditions);

sour = Refers to the untreated sour inlet raw gas. Acid gas is typically comprised of CO_2 and H_2S;

sweet = Refers to the treated gas after the H_2S and CO_2 have been removed (typically sales gas or pipeline quality gas);

CO_2 mole% = Molar (or volume) concentrations of the sour and sweet gas. If the sweet gas concentration is unknown, 0% can be applied as a simplifying assumption, recognizing that this will likely overestimate emissions. Note, pipeline gas specifications typically limit CO_2 concentrations to 2% or less; and

Molar volume conversion = Conversion from molar volume to mass (379.3 scf/lbmole or 23.685 Sm^3/kgmole).

The accuracy of Equation 6-17 is highly dependent on the consistency of the CO_2 concentration in the inlet raw gas and sales gas streams. To improve the accuracy of this method, a volume weighted-average CO_2 concentration should be determined (especially for the inlet gas) using a range of gas sample data.

Note that technologies such as the Molecular Gate® process that remove CO_2 and route the CO_2-rich tail gas stream to the fuel gas system must properly account for the CO_2 emissions. This would involve using the above material balance approach to account for the CO_2 emissions from the acid gas treatment that should be combined with CO_2 formed from combustion that is estimated using the approaches in Section 4 (i.e., the CO_2 removed by the acid gas treatment process gets emitted from the combustion stack with the CO_2 formed from combustion). Care should be taken not to double count these emissions. If the tail gas stream from the Molecular Gate® process is vented, the material balance approach should properly account for the vented CO_2 emissions.

Estimating vented CO_2 emissions from sour gas processing is demonstrated in Exhibit 6-17.

EXHIBIT 6-17: Sample Calculation for CO_2 Venting Emissions from Sour Gas Processing

INPUT DATA:
An amine unit has the following operating parameters:

Unit inlet stream: 150,000 $\times 10^6$ scf/yr sour gas processed with 3.0 mole % CO_2
Unit outlet stream: 148,500 $\times 10^6$ scf/yr sweet gas produced with 2.0 mole % CO_2

Calculate the vented CO_2 emissions.

CALCULATION METHODOLOGY:
The CO_2 vented emissions are estimated using the material balance from Equation 6-18.

$$E_{CO_2} = \left(\frac{150{,}000\times10^6 \text{ scf gas}}{\text{yr}} \times \frac{0.030 \text{ scf CO}_2}{\text{scf gas}}\right) - \left(\frac{148{,}500\times10^6 \text{ scf gas}}{\text{yr}} \times \frac{0.020 \text{ scf CO}_2}{\text{scf gas}}\right)$$
$$\times \frac{\text{lbmole CO}_2}{379.3 \text{ scf CO}_2} \times \frac{44 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonnes}}{2204.62 \text{ lb}}$$

$$\underline{E_{CO_2} = 80{,}506 \text{ tonnes/yr CO}_2}$$

CH_4 emissions are estimated by applying the emission factor from Table 6-19.

$$E_{CH_4} = \frac{150{,}000\times10^6 \text{ scf gas}}{\text{yr}} \times \frac{0.0185 \text{ tonnes CH}_4}{10^6 \text{ scf gas}}$$

$$\underline{E_{CH_4} = 2{,}775 \text{ tonnes/yr CH}_4}$$

CO_2 emissions from SRUs that route the sulfur plant tailgas to a thermal oxidizer can also be calculated using a mass balance approach, such as provided in Equation 6-19. CO_2 emissions from SRUs downstream of an amine unit should be calculated using Equation 6-19.

$$E_{CO_2} = FR \times \frac{MW_{CO_2}}{\text{molar volume conversion}} \times MF \times \frac{\text{tonne}}{2204.62\text{ lb}} \qquad \text{(Equation 6-19)}$$

where:

E_{CO_2} = CO_2 emissions (tonnes/yr);
FR = Volumetric flow rate of acid gas to SRU (scf/yr);
MW_{CO_2} = Molecular weight of CO_2 (44 lb/lb-mole);
Molar Volume Conversion = Conversion from molar volume to mass (379.3 scf/lbmole); and
MF = Molecular fraction of CO_2 in sour gas, based on site data.

6.3.9 Storage Tank Emissions

The volume of vented CH_4 emissions from storage tanks in oil and gas operations is dependent on the type of liquid stored and solubility of CH_4 in the liquid at the upstream (or tank feed) temperature and pressure. In production operations, storage tank CH_4 emissions can be significant from crude and condensate flowing directly into an atmospheric tank from a separator at elevated pressure, where primary flash occurs. Where liquids are in contact with a gas phase, as in many oil and gas reservoirs, high pressures will cause some of the gas to go into solution (i.e., thermodynamic equilibrium between the phases will eventually occur). When the high pressure liquid is brought to atmospheric conditions at lower pressures, the solution gas is released through a rapid process called flashing. Storage tanks where CH_4 primary flashing occurs (e.g., initial tanks fed by a high pressure wellhead separator) can be significant sources of CH_4 venting, which could lead to CH_4 emissions in cases where the tank vent is not controlled (e.g., routed to a vapor recovery unit or flare). Crude or condensate containing significant CH_4 in solution, leading to flashing losses, is referred to as ‘unstabilized’ liquid.

Once the pressurized liquid reaches atmospheric pressure and the volatile CH4 has flashed off, the crude or condensate is considered “weathered” or “stabilized”. Unless site-specific data indicate otherwise, stabilized crude or condensate is assumed to have no appreciable CH_4 from flashing.[8]

Although an unplanned and infrequent occurrence, excess CH_4 emissions may also occur from unstabilized crude tanks due to improperly functioning separator dump valves, which may pass gas directly from the separator to the storage tank when the dump valve gets stuck in open position.

While only unstabilized crude or condensate tanks have flashing losses, all crude and condensate storage tanks may also have small levels of CH_4 venting when gas in the vapor space of the tank is displaced through processes known as working and standing losses. Working losses occur during filling and emptying of the tanks as evaporative losses occur and vapor space is displaced.

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[8] Refer to Appendix E for more information on the CH_4 content of “weathered” crude or condensate and other petroleum products.

Standing (breathing) losses occur during storage of the liquid, and can result from diurnal temperature changes affecting the density of the stored liquid and vapor.

Produced water tanks may also contribute to CH_4 vented emissions, though at a lower rate than crude or condensate tanks. Methane is much less soluble in water than in hydrocarbon liquids; therefore, the CH_4 emissions are significantly lower.

6.3.9.1 Flashing Losses from Unstabilized Crude and Condensate Storage Tanks

Unstabilized crude oil and condensate production tanks (primarily fixed roof tanks) emit CH_4 (and potentially CO_2 for a CO_2 -rich stream) through flashing losses, which occur as the liquid 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 phenomenon primarily occurs in production operations; however, flashing emissions can also occur from oil or condensate pipeline pigging.

A variety of calculation methods can be used to estimate flashing losses from production storage tanks and oil and condensate pipeline pigging, as described below.

1. Direct vent measurements – Tank vent emissions can be measured directly for a relatively short duration, providing accurate emissions estimates for the measured tanks, but this approach is generally expensive and time consuming for large numbers of tanks.
2. Process simulators – Flashing losses can be estimated using various professional process simulators, based on detailed model input data such as liquid composition, separator temperature and pressure, storage tank dimensions, and storage tank operating temperature and pressure. These input parameters may not be available in all cases.
3. Laboratory measurements of the GOR from a pressurized liquid sample – Laboratory measurements can be made of the GOR of a pressurized liquid sample from the gas/oil separator. The GHG emissions can be estimated by multiplying the GOR by the crude oil or condensate throughput, and then applying the CH_4 and/or CO_2 composition to the total gas rate to estimate the CH_4 and/or CO_2 emissions.
4. Correlation equations – The Vasquez-Beggs Equation (VBE), standing correlation, and the Alberta Energy and Utilities Board (EUB) rule-of-thumb methods provide computational approaches for estimating tank flashing losses when limited input data are available.
5. Chart approach – A simple chart originally published by Griswold and Ambler in a Society of Petroleum Engineers (SPE) paper and shown in an EPA Gas STAR Lessons Learned presentation provides an estimate for flashing losses based on the separator pressure and oil API gravity. The chart was developed from empirical flash data from laboratory studies and field measurements (Griswold and Ambler, A Practical Approach To Crude Oil Stock Tank Vapor Recovery, May 1978; EPA, Lessons Learned – Installing Vapor Recovery Units on Crude Oil Storage Tanks, October 2003).
6. Emission factors – Measured emissions from a variety of production tanks have been used to develop simple emission factors based on tank throughput.

Figure 6-3 summarizes the above methods for estimating flashing loss emissions. Using measured test data is the most rigorous approach for determining the flashing loss emissions.

However, such test data may not be available. Other estimation methods include computer programs or process simulators, if sufficient input data are available. Correlation equations and the chart approach may be used with less input data than the software programs or process simulators require, but some basic process parameters are still needed (such as the separator pressure). A simple emission factor approach is provided if only limited data are available.

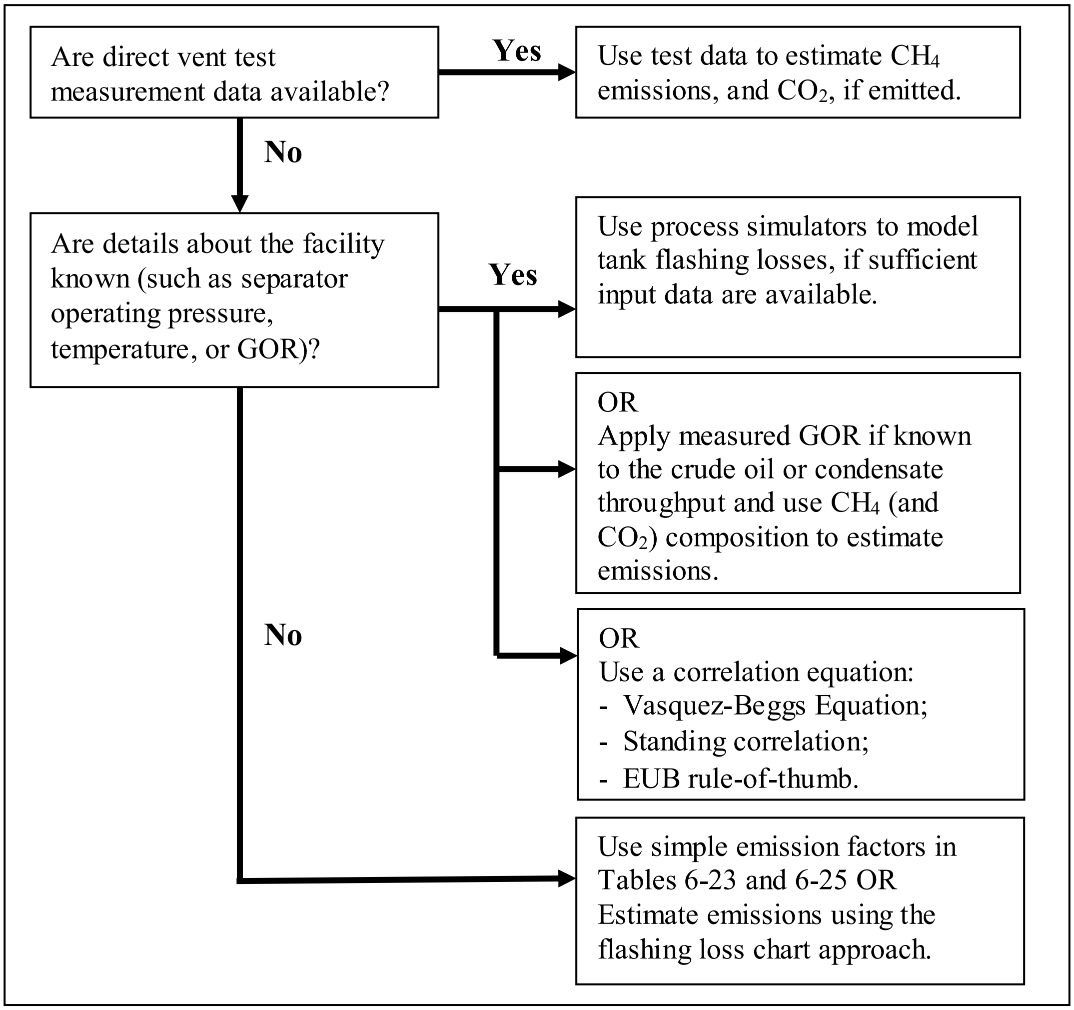

Figure 6-3. Decision Tree for Unstabilized Storage Tank Flashing Losses

Estimated flashing losses should be adjusted for any vapor recovery methods that may be employed. These vapor recovery methods include capturing the flash gas and sending it back for beneficial reuse (e.g., sales, on-site fuel use), or routing the flash gas to a control device such as a flare or vapor combustion unit. If vapor recovery is used, then the flashing losses should be estimated using the above approaches, incorporating the collection efficiency as appropriate to estimate the uncollected emissions. If a flare or vapor combustion unit is used to control the flashing losses, then the methods described in Section 5 should be used to estimate the controlled flash gas combustion emission rates.

Flashing Losses from Computer Simulation Programs

If sufficient input data is available, operators may choose to estimate flashing losses with process simulators instead of the correlation approaches described below. The results could differ between the process simulators and the correlation equations or chart approach due to different assumptions used by each approach. However, if very limited input data is available, a simple emission factor approach may be used.

The use of correlation equations and emission factors for estimating flashing losses from crude oil, condensate, and produced water storage tanks are discussed in the following subsections. Example calculations are provided for these approaches.

Vasquez-Beggs Equation (VBE) (Correlation Equation Approach)

The Oklahoma Department of Environmental Quality provides guidance on using the VBE to estimate tank flashing loss emissions from storage tanks (OK DEQ, 2016; EIIP, 1999; Vasquez, 1980). This method may be used for calculating flashing emissions from crude oil and condensate storage tanks. The first step in calculating the flashing loss emissions is to calculate the specific gravity of the gas at 100 psig, as shown in Equation 6-20:

$$SG_X = SG_i \times \left[1.0+0.00005912 \times API \times T_i \times Log\left(\frac{P_i+14.7}{114.7}\right)\right] \qquad \text{(Equation 6-20)}$$

where:

SG_X = Dissolved gas gravity at 100 psig;
SG_i = Dissolved gas gravity at initial conditions, where air = 1;
API = API gravity of liquid hydrocarbon at final condition (i.e. stock tank at 60° F);
T_i = Temperature of initial conditions (i.e. separator temperature) (°F); and
P_i = Pressure of initial conditions (i.e. separator pressure) (psig).

The flash GOR is then calculated using Equation 6-21:

$$R_S = C_1 \times SG_X \times (P_i + 14.7)^{C_2} \times \exp\left(\frac{C_3 \times API}{T_i + 460}\right) \qquad \text{(Equation 6-21)}$$

where:

R_S = 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. Calculated using Equation 6-19;
P_i = Pressure of initial conditions (i.e. separator pressure) (psig);
API = API gravity of liquid hydrocarbon at final condition (i.e. stock tank at 60° F); and
T_i = Temperature of initial conditions (i.e. separator temperature) (°F).

For API ≤ 30°API: $C_1 = 0.0362$; $C_2 = 1.0937$; and $C_3 = 25.724$

For API > 30°API: $C_1 = 0.0178$; $C_2 = 1.187$; and $C_3 = 23.931$

The VBE correlation method was developed using regression analyses of experimentally derived data. Below is the range of parameters for the correlation and is recommended to be used within the range of the experimental data used for developing these equations (CAPP, 2002). The Oklahoma Department of Environmental Quality and Texas Commission on Environmental Quality also have guidance on a suggested allowable range and/or suggested default value for each input variable (OK DEQ, 2016; TX CEQ, 2012). If a variable is below a suggested minimum allowable value, the suggested minimum allowable value may be used for that variable. If a variable is above a suggested maximum allowable value, another method is recommend for estimating flashing losses. A suggested default value for a variable may used in the absence of facility-specific data. The various suggested allowable ranges and defaults for the VBE variables are shown in Table 6-20.

Table 6-20. Suggested Allowable and Default Values for VBE

Variable	Suggested Minimum Allowable Value	Suggested Maximum Allowable Value	Suggested Default Value	Reference
SG_i	0.56	1.18	N/A	CAPP, 2002
	0.56	1.18	N/A	TX CEQ 2012
	0.9	N/A	0.9	OK DEQ 2016
API	16° API	58° API	N/A	CAPP, 2002
	16° API	40° API	N/A	TX CEQ 2012
	20° API	60° API	70° API [a]	OK DEQ 2016
T_i	70° F	295 °F	N/A	CAPP, 2002
	70° F [b]	295 °F	N/A	TX CEQ 2012
	N/A	N/A	60° F	OK DEQ 2016
P_i	35 psig	5,253 psig	N/A	CAPP, 2002
	35 psig	5,253 psig	N/A	TX CEQ 2012
	35 psig	N/A	N/A	OK DEQ 2016

Footnotes and Sources:

[a] Note that a suggested default value for API of 70° API is above a suggested maximum allowable value for API to yield a conservative estimate of flashing emissions.

[b] TX CEQ guidance states that if T_i is out of the suggested allowable range, another method is recommended for estimating flashing losses.

The flash gas emissions estimated by the VBE are in terms of total hydrocarbon. Thus, an estimate must be made of the CH_4 content in the tank flash gas vent. Two published studies measured flashing loss emissions from crude oil tanks, including the tank vent gas composition (Ogle, 1997a; Ogle, 1997b; Picard, 1992). The average crude oil tank vent CH_4 content was 27.4 volume % from these reports. A measurement program for production condensate flashing was conducted in east Texas for the Texas Environmental Research Consortium (Hendler et al., 2009). The average condensate tank vent CH_4 content was 36.3 volume % from this study. These values are recommended in the absence of site-specific data. A summary of the results of the three studies is included in Appendix B.

A sample calculation illustrating the use of the VBE applied to flashing loss emissions is provided in Exhibit 6-18(a) below.

EXHIBIT 6-18(a): Sample Calculation for Flashing Loss Emissions –VBE

INPUT DATA:

An oil and gas production facility produces 71.70 m^3/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_4 content nor the tank vent gas specific gravity is known. Flashing losses are not controlled by a vapor recovery system. Calculate flashing loss emissions using the VBE approach.

CALCULATION METHODOLOGY:

The first step is to calculate the flash gas specific gravity adjusted to 100 psig, as shown in Equation 6-8. The flash gas specific gravity at initial conditions, SG_i, is not known, so the recommended default value of 0.90 will be used.

$$SG_X = 0.90 \times \left[1.0 + 0.00005912 \times 48.8 \times 112 \times \text{Log}\left(\frac{28.6+14.7}{114.7}\right)\right]$$

$$SG_X = 0.78$$

The flash gas vent flow rate is calculated below, using the C_1, C_2, and C_3 parameters for an API gravity greater than 30. Note that the output from this equation is in units of scf/bbl oil. The flash GOR is calculated below, as shown in Equation 6-21.

$$R_S = 0.0178 \times (0.78) \times (28.6+14.7)^{1.187} \times \exp\left(\frac{23.931 \times 48.8}{112+460}\right)$$

$$R_S = 9.33 \text{ scf/bbl oil}$$

Next, the output from the Vasquez-Beggs equation is converted to SI units using conversion factors from Table 3-4:

$$R_S = \frac{9.33 \text{ scf gas}}{\text{bbl crude}} \times \frac{\text{m}^3 \text{ gas}}{35.3147 \text{ scf gas}} \times \frac{\text{bbl crude}}{0.1589873 \text{ m}^3 \text{ crude}}$$

$$R_S = \frac{1.66 \text{ m}^3 \text{ gas}}{\text{m}^3 \text{ crude}}$$

The flash gas contains gases besides CH_4 and thus the R_S must be multiplied by the tank vent CH_4 content. The tank vent CH_4 content is not known, so the recommended default concentration of 27.4 volume % CH_4 will be used. The molar volume conversion is included below, taken from Table 3-3. Thus, the CH_4 emissions are estimated as:

$$E_{CH_4} = \frac{1.66 \text{ m}^3 \text{ gas}}{\text{m}^3 \text{ crude}} \times \frac{71.70 \text{ m}^3 \text{ oil}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{\text{kgmole gas}}{23.685 \text{ m}^3} \times \frac{27.4 \text{ kgmole CH}_4}{100 \text{ kgmole gas}}$$
$$\times \frac{16 \text{ kg CH}_4}{\text{kgmole CH}_4} \times \frac{\text{tonne}}{1000 \text{ kg}}$$

$$\underline{E_{CH_4} = 8.04 \text{ tonnes CH}_4/\text{yr}}$$

Standing Correlation (Correlation Equation Approach)

The Canadian Association of Petroleum Producers, *Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities,* 2002 document (CAPP, 2002), includes a standing correlation to estimate flashing losses. This method may be used for estimating flashing losses from crude oil and condensate. This correlation is shown in Equation 6-22.

$$GOR = SG_{\text{flash gas}} \times \left(\frac{P}{519.7 \times 10^{y_g}}\right)^{1.204} \qquad \text{(Equation 6-22)}$$

where:

GOR = Ratio of flash gas production to oil produced, in m^3/m^3 oil;

$SG_{\text{flash gas}}$ = Specific gravity of the solution gas with respect to air, where air = 1, dimensionless[9]. A suggested default value for $SG_{\text{flash gas}}$ is 0.90 (OK DEQ, 2016);

P = Absolute pressure in vessel of interest, kPa;

y_g = $1.225 + 0.00164 \times T - \frac{1.769}{SG_{oil}}$;

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[9] This value can also be calculated as ratio of molecular weight of solution gas to the molecular weight of air (CAPP, 2002).

SG_{oil} = Specific gravity of oil with respect to water = $\frac{141.5}{131.5 + G_{Oil}}$;

G_{oil} = API gravity of stock tank oil at 60°F, °API; and

T = Temperature in vessel of interest, °K.

Note that the units for the standing correlation variables are different than the VBE, so caution should be exercised if both of these methods are used to estimate the flashing losses. For the situation where the flash occurs from a separator to an atmospheric tank, the term in parenthesis must be evaluated separately for the separator and the storage tank. For this scenario, Equation 6-22 would be expressed as shown:

$$GOR = SG_{\text{flash gas}} \times \left[\left(\frac{P}{519.7 \times 10^{y_g}} \right)^{1.204}_{\text{Separator}} - \left(\frac{P}{519.7 \times 10^{y_g}} \right)^{1.204}_{\text{Storage Tank}} \right] \qquad \text{(Equation 6-23)}$$

The Standing Correlation method was developed using regression analyses of experimentally derived data. Table 6-21 below presents the range of parameters for the correlation and is recommended to be used within the range of the experimental data used for developing this equation.

Table 6-21. Summary of Range of Data Used in Standing Correlation [a]

Parameter	Standing Correlation
Size of Dataset	105
Bubble Pressure (kPa)	895 to 48,250
Reservoir Temperature (°C)	38 to 126
Solution Gas-to-Oil Ratio at Bubble Point Pressure (m^3/m^3)	3.5 to 254
Oil Specific Gravity (°API)	16.5 to 63.8
Vapor Specific Gravity	0.59 to 0.95

Footnotes and Sources:

[a] Data obtained from the Canadian Association of Petroleum Products (CAPP) *Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities*, Publication Number 2002-0009, May 2002.

Similar to the VBE correlation approach, the flash gas emissions estimated using the standing correlation is provided in terms of total hydrocarbon and must be converted to a CH_4 emissions basis. As noted earlier, a default of 27.4 volume % CH_4 is assumed for crude oil and 36.3 volume % CH_4 is assumed for condensate in the absence of site-specific data (Ogle, 1997a; Ogle, 1997b; Picard, 1992; Hendler et al., 2009).

A sample calculation illustrating the use of the standing correlation approach follows in Exhibit 6-18(b):

EXHIBIT 6-18(b): Sample Calculation for Flashing Loss Emissions – Standing Correlation

INPUT DATA:

The facility is the same oil and gas production facility described in Exhibit 6.3-14(a) for the VBE correlation approach. Namely, 451 bbl/day (71.70 m^3/day) of crude (48.8° API gravity) is produced, and flashing losses occur as the oil flows from a separator at 28.6 psig (197.2 kPa gauge) and 112°F (44.4 °C) to an atmospheric tank. The atmospheric temperature (and thus the storage tank temperature) is assumed to be 80°F (299.8 K). (Note that the atmospheric temperature was not needed for the VBE approach presented earlier.) Flashing losses are not controlled by a vapor recovery system. Calculate the flashing loss emissions using the standing correlation approach.

CALCULATION METHODOLOGY:

Note that the separator absolute pressure is 43.3 psia (28.6 psig + 14.7 psia) while the tank pressure is 1 atm. Thus, the pressures in kPa are:

$$P_{sep} = (43.3 \text{ psi}) \times \frac{6.894757 \text{ kPa}}{\text{psi}} = \underline{298.5 \text{ kPa}}$$

$$P_{tank} = (1 \text{ atm}) \times \frac{101.325 \text{ kPa}}{\text{atm}} = \underline{101.3 \text{ kPa}}$$

Next, the oil API gravity (G_{oil}) is converted to a specific gravity, using the definition in Equation 6-21:

$$SG_{oil} = \frac{141.5}{131.5 + G_{oil}} = \frac{141.5}{131.5 + 48.8} = \underline{0.785}$$

Next, the parameter, y_g, can be calculated 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), using the definition in Equation 6-21:

$$y_{g,\ sep} = 1.225 + (0.00164) \times (317.6) - \frac{1.769}{0.785} = -0.5076$$

$$y_{g,\ tank} = 1.225 + (0.00164) \times (299.8) - \frac{1.769}{0.785} = -0.5368$$

Thus, the input parameters for the standing correlation approach have been defined, and are summarized below:

$SG_{flash\ gas} = 0.90$ (assume the default value in the absence of data)
$P_{sep} = 298.5$ kPa
$P_{tank} = 101.3$ kPa
$y_{g,\ sep} = -0.5076$
$y_{g,\ tank} = -0.5368$

The flash gas vent flow rate is calculated below, using Equation 6-23 and the above parameters.

$$\text{GOR} = (0.90)\times\left[\left(\frac{298.5}{519.7\times10^{-0.5076}}\right)^{1.204}_{\text{Separator}} - \left(\frac{101.3}{519.7\times10^{-0.5368}}\right)^{1.204}_{\text{Storage Tank}}\right] = 1.329\ \text{m}^3\ \text{gas/m}^3\ \text{oil}$$

The flash gas contains gases besides CH_4 and must be multiplied by the tank vent CH_4 content. The tank vent CH_4 content is not known, so the recommended default concentration of 27.4 volume % CH_4 will be used. Thus, the CH_4 emissions are estimated as:

$$E_{CH_4} = \frac{1.329\ \text{m}^3\ \text{gas}}{\text{m}^3\ \text{oil}} \times \frac{71.7\ \text{m}^3\ \text{oil}}{\text{day}} \times \frac{35.3147\ \text{ft}^3(\text{scf})\ \text{gas}}{\text{m}^3} \times \frac{\text{lb mole gas}}{379.3\ \text{scf gas}} \times$$

$$\frac{27.4\ \text{lbmole CH}_4}{100\ \text{lbmole gas}} \times \frac{365\ \text{day}}{\text{yr}} \times \frac{16\ \text{lb CH}_4}{\text{lbmole CH}_4} \times \frac{\text{tonne}}{2204.62\ \text{lb}}$$

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

Alberta Energy and Utilities Board (EUB) Rule-of-Thumb (Correlation Equation Approach)

The CAPP document, *Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities*, includes the EUB rule-of-thumb approach to estimate flashing losses (CAPP, 2002). CAPP reports that this approach tends to yield flashing loss estimates biased high and is recommended for facilities with low oil volumes, established pools, mature pools with declining GORs, and some heavy oil production facilities (CAPP, 2002). The EUB rule-of-thumb correlation should not be used for condensate since this approach is specific to crude oil and does not take into account the condensate physical properties.

The EUB rule-of-thumb equation is:

$$V_s = 0.0257\times V_o\times\Delta P \qquad \text{(Equation 6-24)}$$

where:

V_s = Volume of gas released, m^3;
V_o = Oil production volume, m^3; and
ΔP = Pressure drop to atmospheric tank, kPa.

Similar to the VBE and standing correlation approaches, the flash gas emissions estimated using the EUB rule-of-thumb approach are in terms of total hydrocarbon and must be converted to a CH_4 emissions basis. As noted earlier, a default of 27.4 volume % CH_4 is assumed for crude oil in the absence of site-specific data (Ogle, 1997a; Ogle, 1997b; Picard, 1992).

A sample calculation illustrating the use of the EUB rule-of-thumb approach follows in Exhibit 6-18(c).

EXHIBIT 6-18(c): Sample Calculation for Flashing Loss Emissions – EUB Rule-of-Thumb

INPUT DATA:

The facility is the same oil and gas production facility described in Exhibits 6.3-14(a) and 6.3-14(b) for the other two correlation approaches. For illustrative purposes, this exhibit shows how CO_2 emissions would be estimated as well. For this facility, the CO_2 tank vent concentration is assumed to be approximately 4.5 volume %. Calculate the flashing loss emissions using the EUB rule-of-thumb approach.

CALCULATION METHODOLOGY:

Note that the separator gauge pressure, 197.2 kPa gauge psig, is equal to the pressure drop from the separator to the atmospheric storage tank (i.e., 298.5 kPaa – 101.3 kPa = 197.2 kPa). Thus, the pressure drop in kPa is:

$\Delta P = 197.2$ kPa

The flash gas vent flow rate is calculated below, using the parameters in the proper units:

$V_s = 0.0257 \text{ x } 71.7 \text{ m}^3 \text{ oil/day x } 197.2 \text{ kPa} = 363.4 \text{ m}^3\text{/day}$

The flash gas contains gases besides CH_4 and must be multiplied by the tank vent CH_4 content. The tank vent CH_4 content is not known so the recommended default concentration of 27.4 volume % CH_4 will be used. Thus, the CH_4 emissions are estimated as:

$$E_{CH_4} = \frac{363.4 \text{ m}^3 \text{ gas}}{\text{day}} \times \frac{35.3147 \text{ ft}^3 \text{ (scf) gas}}{\text{m}^3} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \times \frac{27.4 \text{ lbmole CH}_4}{100 \text{ lbmole gas}} \times \frac{365 \text{ day}}{\text{yr}}$$

$$\times \frac{16 \text{ lb CH}_4}{\text{lbmole CH}_4} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CH_4} = 24.56 \text{ tonnes CH}_4\text{/yr}}$$

$$E_{CO_2} = \frac{363.4 \text{ m}^3 \text{ gas}}{\text{day}} \times \frac{35.3147 \text{ ft}^3 \text{ (scf)gas}}{\text{m}^3} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \times \frac{4.5 \text{ lbmole CO}_2}{100 \text{ lbmole gas}} \times \frac{365 \text{ day}}{\text{yr}}$$

$$\times \frac{44 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CO_2} = 11.09 \text{ tonnes CO}_2\text{/yr}}$$

Flashing Loss Chart Based on API Gravity and Pressure

The EPA Gas STAR program provides a chart that was originally published by Griswold and Ambler (Griswold et al, 1978) and can be used to estimate crude oil flashing losses. The chart provides the flash gas volume-to-oil ratio from the tank as a function of the crude oil API gravity and pressure of the separator immediately upstream of the tank. Gas STAR reports that the graph was constructed using empirical flash data from laboratory studies and field measurements (EPA, 2003b; Lessons Learned – Installing Vapor Recovery Units on Crude Oil Storage Tanks, October 2003). The flashing loss chart is presented in Figure 6-4 and is taken from a Gas STAR Lessons Learned presentation (EPA, 2007a).

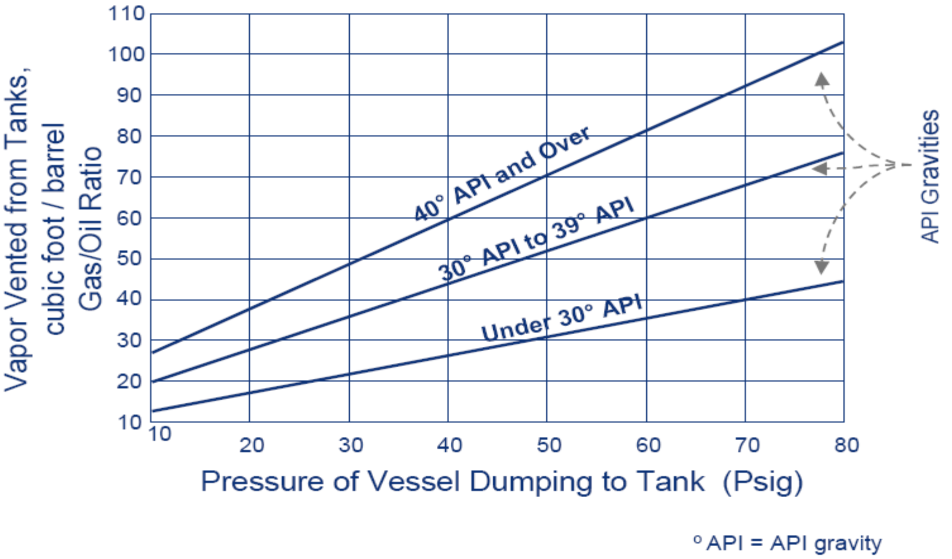

Figure 6-4. Flashing Losses Chart

Source for chart: 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 (EPA, 2007a).

A sample calculation illustrating the use of the chart taken from EPA Gas STAR to estimate flashing losses is given below in Exhibit 6-19.

EXHIBIT 6-19: Sample Calculation for Tank Flashing Losses – Chart Approach

INPUT DATA:

The facility is the same oil and gas production facility described in Exhibit 6.3-14(a) for the VBE correlation approach. Namely, 451 bbl/day of crude (48.8° API gravity) is produced, 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). Note that the separator and the tank temperatures are not needed for the chart approach. Calculate the CH_4 emissions using the chart approach.

CALCULATION METHODOLOGY:

The chart provided in Figure 6-4 will be used to estimate the tank flashing loss emissions. Given a separator pressure of 28.6 psig, and an API gravity of 48.8°, Figure 6-4 shows that the flash vapor-to-oil ratio is approximately 47 scf/bbl (reading on the line indicated in the chart as "40° API and Over"). Thus, the GOR is:

GOR = 47 scf/bbl

The flash gas contains gases besides CH_4 and must be multiplied by the tank vent CH_4 content. The tank vent CH_4 content is not known so the recommended default concentration of 27.4 volume % CH_4 will be used. Thus, the CH_4 emissions are estimated by multiplying the GOR by the oil production rate (assuming 365 days/yr of operation) and the assumed CH_4 concentration in the tank flash gas, as shown below:

$$E_{CH_4} = \frac{47\text{ scf gas}}{\text{bbl crude}} \times \frac{451\text{ bbl oil}}{\text{day}} \times \frac{365\text{ day}}{\text{yr}} \times \frac{\text{lbmole gas}}{379.3\text{ scf}} \times \frac{27.4\text{ lbmole CH}_4}{100\text{ lbmole gas}} \times \frac{16\text{ lb CH}_4}{\text{lbmole CH}_4}$$

$$\times \frac{\text{tonne}}{2204.62\text{ lb}}$$

$$\underline{E_{CH_4} = 40.6\text{ tonnes CH}_4\text{/yr}}$$

Emission Factor Approach For Crude Oil Tank Flashing

In the absence of site-specific data to quantify flashing losses from crude oil storage tanks, a default emission factor approach can be used. Table 6-22 below presents default emission factors for flashing losses from production segment crude oil storage tanks, taken from EPA's GHGI (EPA, 2019b). The default emission factors are broken down by tank throughput: large tanks with an annual average daily throughput of greater than or equal to 10 barrels; and small tanks with an annual average daily throughput of less than 10 barrels. Note that the GHGI emission factors are based on data reported to EPA in the US through the GHGRP, which requires measurement or simulation for large tanks and allows a default emission factor approach for small tanks (with annual average throughput of less than 10 barrels per day).

The average value also presented in Table 6-22 below is derived from two published studies, one by API/GRI (Ogle, 1997a; Ogle, 1997b) and the other by the Canadian Petroleum Association (Picard, Vol. III, 1992). A summary of the results of these studies, including development of an average tank CH_4 flashing loss emission factor, is included in Appendix B.

Table 6-22. Methane Flashing Loss Emission Factors for Crude Oil Storage Tanks

Emission Source	Original Units, Crude Oil Methane Flashing Loss Emission Factor (kg CH_4/bbl crude)	Uncertainty (±%)	Crude Oil Methane Flashing Loss Emission Factor, Converted to Tonnes Basis (tonnes CH_4/m^3 crude)	Separator Methane Content Basis of Factor [a] (mole %)
Large Tanks (≥ 10 bbl crude/day) [b]				
Without control [c, d]	0.193	Not specified	1.21E-03	81.6
With VRU [c, d]	0.0283		1.78E-04	
With flares [c, d]	5.25E-3		3.30E-05	
Small Tanks (< 10 bbl crude/day) [b]				
Without control [c, d]	0.0184	Not specified	1.15E-04	81.6
With flares [c, d]	2.06E-3		1.29E-05	
Average Value				
Without control [e, f, g, h]	0.886	110 [i]	5.57E-03	78.8

Footnotes and Sources:

[a] Gas content taken from GHGI Annex 3.6 Table 3.6-3 for U.S. Production segment Methane Content in Natural Gas by NEMS Region (General Sources). For the lower 48 states, in 2017, CH_4 content at 81.6 mol%. The CH_4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH_4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions. Average value factors based on separator CH_4 content of 78.8% (vol.); can ratio to other separator concentrations.

[b] Differentiation in throughput cited from U.S. Environmental Protection Agency (USEPA), 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. (EPA, 2019a). Data reported as of August 2, 2019. https://ecfr.io/Title-40/sp40.23.98.w.

[c] EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017. (EPA, 2019b). These values were calculated using year-specific GHGRP Subpart W data for each control category (2017b). Note: These factors, used in the USEPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017 (EPA 2019), are updated annually based on data reported from operators under the GHGRP.

[d] Factors presented as kg CH_4/bbl were originally represented in the GHGI as kg CH_4/MMbbl.

[e] 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.

[f] 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.

[g] Picard, D. J., B. D. Ross, and D. W. H. Koon. *Inventory of CH_4 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.

[h] Factors presented as kg CH_4/bbl were originally represented in the data summary as lb CH_4/bbl.

[i] Uncertainty based on a 95% confidence interval.

The factors above in Table 6-22 can be used when the amount of produced crude is known. For small tanks with throughput less than 10 bbl/day, when the amount of produced crude is not known or cannot be estimated, the following factors from EPA's GHGRP can be used (EPA, 2019):

4.2 Mscf CH_4/separator/year (Original Units) [a, b]
0.081 tonne CH_4/separator/year (Converted)
2.8 Mscf CO_2/separator/year (Original Units) [a, b]
0.15 tonne CO_2/separator/year (Converted)

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (USEPA), 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Data reported as of August 2, 2019. https://ecfr.io/Title-40/sp40.23.98.w. (EPA, 2019a).

[b] Uncertainty for these values is not specified.

A sample calculation illustrating the use of the simple emission factor approach is given below in Exhibit 6-20.

EXHIBIT 6-20: Sample Calculation for Tank Flashing Losses - Simple Emission Factor Approach

INPUT DATA:

An oil and gas production facility produces 451 bbl/day of crude oil (same as the previous exhibit). The separator gas (to sales pipeline) CH_4 content is 58 volume %. Calculate the CH_4 emissions from tank flashing losses using the large tank, uncontrolled emission factor.

CALCULATION METHODOLOGY:

The CH_4 flashing losses are calculated using the large tank uncontrolled emission factor provided in Table 6-22. Please note that even though this emission factor is based on 81.6 mole % CH_4 in the separator gas, the emission factor is not adjusted for CH_4 content in the separated associated gas. Tank flashing losses are not a simple linear function of the CH_4 content in the separator gas stream, but rather the solubility of CH_4 in crude at the pressure and temperature conditions of the separator, properties of the crude, etc.

$$E_{CH_4} = \frac{451 \text{ bbl crude}}{\text{day}} \times \frac{365 \text{ day}}{\text{year}} \times \frac{0.193 \text{ kg } CH_4}{\text{bbl}} \times \frac{\text{tonne } CH_4}{1000 \text{ kg } CH_4}$$

$$\underline{E_{CH_4} = 31.8 \text{ tonne } CH_4/\text{yr}}$$

Exhibits 6.3-14(a), (b), and (c) demonstrate the use of the VBE, standing, and EUB rule-of-thumb correlation approaches, respectively. Additionally, Exhibits 6.3-15 and 6.3-16 demonstrate the use of the chart and simple emission factor approaches, respectively. These exhibits were based on operating parameters presented in a testing program prepared for API, GRI, and CAPP to evaluate API's E&P TANK software (Ogle, 1997b). Site number 5 from this study was used for the exhibit calculations. This study presented both measured flashing loss data as well as the results obtained for the test site using E&P TANK software, version 3.0.

Table 6-23 summarizes tank flashing loss emission estimates for the various approaches presented. As shown, the EUB rule-of-thumb approach results in the highest flashing loss emission estimate for the three correlation approaches. This is consistent with information from CAPP, 2002, which states that this approach provides estimates biased high. The VBE correlation results in an emission estimate that is higher than the standing correlation for the exhibit calculation. The measured emission estimate is less than all of the correlation approaches except the standing correlation. The chart approach yields an estimate that is the higher than the correlation approaches, and higher than the simple emission factor approach. The simple emission factor approach provides an estimate that is higher than all but the chart approach; however, it did not rely on many of the input parameters (except for the flow rate, which was taken from the Ogle report for site number 5).

Table 6-23. Summary of Crude Oil Production Tank Flashing Losses Using Different Correlation Equation Approaches

Correlation	Methane Flashing Losses (tonnes/yr)
Vasquez-Beggs Equation (VBE)	8.04 [a]
Standing Correlation	6.44 [b]
EUB Rule-of-Thumb	24.56 [c]
Chart Approach	40.6 [d]
Simple Emission Factor Approach	31.8 [e]
E&P Tanks, Version 3.0	12.75 [f, g]
Measured	9.54 [f, g]

Footnotes and Sources:

[a] Calculation shown in Exhibit 6.3-14(a).

[b] Calculation shown in Exhibit 6.3-14(b).

[c] Calculation shown in Exhibit 6.3-14(c).

[d] Calculation shown in Exhibit 6.3-15.

[e] Calculation shown in Exhibit 6.3-16.

[f] 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. Based on data for Site number 5.

[g] E&P TANK also uses the pressurized oil composition as an input. Annual emissions for the measured data are estimated from the hourly rate assuming continuous annual operation.

Note that the comparison in Table 6-23 is not comprehensive because it is for only one set of conditions presented at one site. Thus, no conclusion can be drawn with regard to the relative estimates provided by the different approaches for this single example. However, Gas STAR notes that the chart approach will provide estimates that have an uncertainty of ± 50% (EPA, 2007c). Gas STAR also notes that the E&P TANK software and VBE approach provide emission estimates that are ± 20%, while measured data using recording manometer and well tester or ultrasonic meter over several cycles will provide estimates that are ± 5%. Derivation of the simple average value emission factor (provided in Appendix B) results in an uncertainty of ± 110%.

The choice of using the EUB rule-of-thumb versus the VBE or standing correlation depends on the available data; the EUB rule-of-thumb requires less input data than the other two approaches. If sufficient data are available for the VBE or standing correlation approaches, the choice of one approach over the other is left to the discretion of the user. The simple emission factor should only be used when very limited input data are available (and, thus the other approaches cannot be used).

Emissions from Methane Entrained in Condensate

Condensate collected in the production segment may contain entrained CH_4, which can result in flashing losses as the condensate is brought to atmospheric conditions. Emission factors for production condensate flashing are presented below in Table 6-24, taken from EPA's GHGI (EPA, 2019b). Similar to crude flashing losses, the condensate tank default emission factors are broken down by tank throughput: large tanks with an annual average daily throughput of greater than or equal to 10 barrels; and small tanks with an annual average daily throughput of less than 10 barrels. Note that the GHGI emission factors are based on data reported to EPA in the US through the GHGRP, which requires measurement or simulation for large tanks and allows a default emission factor approach for small tanks (with annual average throughput of less than 10 barrels per day).

The average emission factor for production condensate flashing was derived from a measurement program conducted in east Texas for the Houston Advanced Research Center (Hendler et al., 2009), and is presented below. The development of this CH_4 emission factor is presented in Appendix B.

Table 6-24. Production Condensate Flashing Emission Factors

Emission Source	Original Units, Condensate Methane Flashing Loss Emission Factor (kg CH_4/bbl condensate)	Uncertainty (± %)	Condensate Methane Flashing Loss Emission Factor, Converted to Tonnes Basis (tonnes CH_4/ m^3 condensate)	Separator Methane Content Basis of Factor [a] (mole %)
Large Tanks (≥ 10 bbl/day) [b]				
Without control [c]	0.146	Not specified	9.17E-4	81.6%
With VRU [c]	6.65E-3		4.19E-5	

Emission Source	**Original Units, Condensate Methane Flashing Loss Emission Factor (kg CH_4/bbl condensate)**	**Uncertainty (± %)**	**Condensate Methane Flashing Loss Emission Factor, Converted to Tonnes Basis (tonnes CH_4/ m^3 condensate)**	**Separator Methane Content Basis of Factor [a] (mole %)**
With flare [c]	5.79E-3		3.64E-5	
Small Tanks (< 10 bbl/day) [b]				
Without flare [c]	0.119	Not specified	7.49E-4	81.6%
With flare [c]	9.10E-4		5.73E-6	
Average Value				
Without control [d, e]	2.30	101 [f]	1.45E-2	Not specified

Footnotes and Sources:

[a] Gas content taken from GHGI Annex 3.6 Table 3.6-3 for U.S. Production segment Methane Content in Natural Gas by NEMS Region (General Sources). For the lower 48 states, in 2017, CH_4 content at 81.6 mol%. The CH4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH_4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

[b] Differentiation in throughput cited from U.S. Environmental Protection Agency (USEPA), 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Data reported as of August 2, 2019. https://ecfr.io/Title-40/sp40.23.98.w. (EPA, 2019a). Note: These factors, used in the USEPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017 (EPA 2019), are updated annually based on data reported from operators under the GHGRP.

[c] EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017. 2019. These values were calculated using year-specific GHGRP Subpart W data for each control category (EPA, 2017b).

[d] Hendler, Albert, Jim Nunn, Joe Lundeen, Ray McKaskle. *VOC Emissions from Oil and Condensate Storage Tanks*, Final Report, prepared for Houston Advanced Research Center (HARC), October 31, 2006 (Cited Tables 3-3 and 3-5).

[e] Factors presented as kg CH_4/bbl were originally represented in the data summary as lb CH_4/bbl.

[f] Uncertainty based on a 95% confidence interval.

The factors above in Table 6-24 can be used when the amount of produced condensate is known. For small tanks with throughput less than 10 bbl/day, when the amount of produced condensate is not known or cannot be estimated, the following factors from EPA's GHGRP can be used (EPA, 2019a):

17.6 Mscf CH_4/separator/year (Original Units) [a, b]
0.338 tonne CH_4/separator/year (Converted)
2.8 Mscf CO_2/separator/year (Original Units) [a, b]
0.15 tonne CO_2/separator/year (Converted)

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (USEPA), 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Data reported as of August 2, 2019. https://ecfr.io/Title-40/sp40.23.98.w. (EPA, 2019a).

[b] Uncertainty for these values is not specified.

6.3.9.2 Improperly Functioning Separator Dump Valve Emissions from Unstabilized Crude and Condensate Tanks

Separator or scrubber dump valves open periodically to reduce the accumulation of liquids in the separator. Scrubber dump valves can get stuck open due to debris preventing them from closing properly. When the dump valve is stuck open, natural gas from the separator may be vented to the atmosphere through the storage tank.

EPA's GHGRP requires producers to record the number of hours the dump valve was malfunctioning and provides the following equation for estimating vented emissions during valve malfunctioning (EPA, 2019a).

$$E_{\text{Dump Valve}} = CF \times E \times \frac{\text{yr}}{8{,}760 \text{ hours}} \times T \qquad \text{(Equation 6-25)}$$

where:

$E_{\text{Dump Valve}}$ = Annual volumetric GHG emissions resulted from dump valve malfunction (scf/year); and
CF = Correction factor for tank emission for a period of time, (dimensionless). For separators in crude oil service, use 2.87, and for separators in condensate service, use 4.37; and
E = Storage tank emissions (scf/year); and
T = Number of hours of dump malfunction (hours/year).

See Equation 6-2 for an example of the conversion of volumetric emissions to mass emissions.

Table 6-25 presents emission factors for improperly functioning separator dump valves, from EPA's GHGI (EPA, 2019b).

Table 6-25. Improperly Functioning Separator Dump Valve Emission Factors

Emission Source	Original Units, Emission Factor [a] (kg CH_4/bbl)	Uncertainty (± %)	Converted, Emission Factor (tonne CH_4/m^3)	Methane Content Basis of Factor [b] (mole %)
Malfunctioning separator dump valves, in crude service [a]	2.70E-3	Not specified	1.70E-5	81.6%
Malfunctioning separator dump valves, in condensate service [a]	2.64E-3	Not specified	1.66E-5	81.6%

Footnotes and Sources:

[a] EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017. 2019. These values were calculated using year-specific GHGRP Subpart W data for each control category (2017b). Note: These factors, used in the USEPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017 (EPA, 2019b), are updated annually based on data reported from operators under the GHGRP.

[b] Gas content taken from GHGI Annex 3.6 Table 3.6-3 for U.S. Production segment Methane Content in Natural Gas by NEMS Region (General Sources). For the lower 48 states, in 2017, CH_4 content at 81.6 mol%. The CH_4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH_4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

6.3.9.3 Stabilized Tanks Working/Standing Losses

Liquid petroleum storage tanks can produce hydrocarbon emissions through working and standing (breathing) losses. These storage tanks include crude oil and condensate tanks in production and intermediate tanks at a refinery. Tank types include fixed roof tanks as well as floating roof tanks. Working loss emissions occur during the filling and emptying of the tanks as evaporative losses occur and vapor space is displaced. Standing losses occur during storage of the liquid, and can result from diurnal temperature changes.

Because most of the CH_4 and CO_2 emissions from crude storage tanks occur as a result of flashing (refer to Section 6.3.9.1), working and breathing loss emissions of these gases are very small in production and virtually non-existent in the downstream segments. Unless site-specific data indicate otherwise, "weathered" crude or condensate and other refined petroleum products can be assumed to contain negligible CH_4 or CO_2. Therefore, it can also assumed that there are negligible CH_4 or CO_2 emissions from the working and breathing losses of tanks containing "weathered" crude, condensate, or other refined petroleum products. This assumption is described in more detail in Appendix D.

EPA provides a methodology for estimating tank hydrocarbon emissions (as total hydrocarbon [THC] or VOC) due to tank working and standing losses, where sites choose to estimate CH_4 and CO_2 emissions from this source. EPA's methodology can be found in Chapter 7 of AP-42[10] (EPA, 2020a).

EPA's methodology is primarily directed at estimating THC or VOC. The user would have to estimate the total emissions from the tank and then multiply the total emissions by the concentration of CH_4 and/or CO_2 in the tank vent stream. The CH_4 and/or CO_2 concentrations should be based on site data if they are available.

Alternatively, tank working and standing losses can be modeled using simulation software, similar to that described above for flashing losses. To simulate the working and standing losses, however, the CH_4 and/or CO_2 content of the crude oil or condensate at the pressurized conditions feeding the tank or the atmospheric conditions in the tank would be needed depending on whether or not the simulation software could estimate the composition of the atmospheric conditions.

6.3.9.4 Produced Water Tank Emissions

Produced water tank emissions occur in a manner similar to crude oil or condensate storage tank flashing losses, though at a smaller relative rate. Methane emissions from produced water tanks are lower than crude oil or condensate tank flashing losses because CH_4 has a stronger affinity for hydrocarbon oil than it does for water. Thus, more CH_4 is dissolved in the oil phase than the water phase.

Direct measurement, process simulation, and general industry emission factors can be used to quantify flashing losses from produced water tanks. However, API's E&P Tanks v3.0 program

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[10] 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).

(API, 1997b; API, 2014) and the VBE are based on properties specific to crude oil and, therefore are not applicable to water tanks.

Table 6-26 presents default emission factors from produced (salt) water tanks. These emission factors were developed from data presented in Volume 6 of the 1996 GRI/EPA study (Shires et al, 1996c). The GRI/EPA study estimated produced water emissions based on process simulator modeling for salt contents of 2, 10, and 20%, and pressures of 50, 250, and 1000 psi. The original emission factors are converted from a total CH_4 mass rate to tonnes CH_4 per volume of produced water based on the national produced water volume used in the original process simulations (Energy Environmental Research Center, 1995).

Table 6-26. Produced Salt Water Tank Methane Flashing Emission Factors

Separator Pressure (psi)	Produced Water Salt Content	GRI/EPA Emission Rate [a], Original Units (10^6 lb CH_4/yr)	Water Tank Emission Factor	
			tonne CH_4 /1000 bbl produced water [b]	tonne CH_4 /1000 m^3 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
250	**Average of 10.7% [c]**	**--**	**0.0142**	**0.08917**
1000	20%	38.8	0.0354	0.22273
1000	10%	58.7	0.0536	0.33697
1000	2%	69.5	0.0634	0.39896
1000	**Average of 10.7% [c]**	**--**	**0.0508**	**0.31955**

Footnotes and Sources:

[a] 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. Uncertainty and CH_4 content were not specified.

[b] Process simulation modeling based on 1990 annual salt water production of 497 million barrels from Energy Environmental Research Center, 1995.

[c] Average of emission factors at 20, 10, and 2% salt.

The Regional Association of Oil, Gas and Biofuels Sector Companies in Latin America and the Caribbean (ARPEL) provides another source of general emission factors for produced water flashing losses (ARPEL, 1998). Table 6-27 presents CH_4 emission factors for produced water from shallow gas wells (76 psi or less). These factors are based on produced water at a temperature of 50°C (122°F). The base emission factor, developed from Chapter 9 of the *API Technical Data Book* (API, 1984), is reported to be extremely approximate (ARPEL, 1998).

Table 6-27. Methane Emission Factors from Produced Water from Shallow Gas Wells

Source Information	Methane Water Tank Emission Factor [a], Original Units (kg/m^3 produced water)	Methane Water Tank Emission Factor, Converted to Tonnes Basis
Shallow gas well (76 psi or less, 50°C)	0.036	0.0057 tonnes/1000 bbl produced water 0.036 tonnes/1000 m^3 produced water

Footnotes and Sources:

[a] Table 3.6 of ARPEL, *Atmospheric Emissions Inventories Methodologies in the Petroleum Industry.* ARPEL Guideline # ARPELCIDA02AEGUI2298, Prepared by Jaques Whitford Environment Limited, December 1998. Uncertainty and CH_4 content were not specified.

A sample calculation illustrating the use of the simple emission factor for produced water emissions is presented below in Exhibit 6-21.

EXHIBIT 6-21: Sample Calculation for Water Tank Emissions – Simple Emission Factor Approach

INPUT DATA:

An oil and gas production facility produces 50 bbl/day of water. The salt content of the water is not known. The separator pressure (immediately upstream of the water tank) is 200 psig. Calculate the CH_4 emissions.

CALCULATION METHODOLOGY:

The CH_4 flashing losses are calculated using the emission factor provided in Table 6-26 for 250 psi. It is recognized that this emission factor biases the estimate high since the actual separator pressure is less than 250 psi. Because the salt content of the produced water is unknown, the emission factor provided for the average salt content is used. The CH_4 emissions are estimated as shown below.

$$E_{CH_4} = \frac{50 \text{ bbl water}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{0.0142 \text{ tonnes } CH_4}{1000 \text{ bbl water}}$$

$$\underline{E_{CH_4} = 0.26 \text{ tonne } CH_4/\text{yr}}$$

Produced water tanks may also use natural gas for tank blanketing for safety purposes. If the blanket gas is vented to the atmosphere, this is a source of CH_4 vented emissions. Refer to Section 6.5.3.1 for a discussion of the approach to quantify emissions from tank blanketing.

6.3.10 CO_2 Enhanced Oil Recovery (EOR) Production-Related Venting Operations

To improve the recovery of oil over the life of a field, different techniques may be used to enhance oil recovery, including the injection of CO_2. In CO_2 enhanced oil recovery (EOR), CO_2 is injected into the field via high pressure injection wells. The CO_2 lowers the viscosity of oil remaining in the formation and effectively pushes it toward producing wells. In this process, the CO_2 becomes miscible with the oil, and as oil continues to be produced over time, the injected CO_2 gradually begins to break through to the producing wells. The majority of CO_2 produced with oil is 'recycled', or separated and reinjected back into the field.

6.3.10.1 CO_2 EOR Unstabilized Crude Storage Tanks

Onshore petroleum production operations that use CO_2 EOR may result in the production of petroleum that has significant amounts of dissolved CO_2. While CO_2 is typically separated from the produced oil and reinjected in a closed loop system, there may be residual dissolved CO_2 in the oil since separation usually takes place at higher than atmospheric pressure. Most of this CO_2 is vented from an atmospheric storage tank immediately downstream of the production separator where the CO_2 flashes out of the liquid hydrocarbons, along with CH_4. These CO_2 emissions from tank flashing would be estimated using methodologies described in Section 6.3.9.

6.3.10.2 EOR Hydrocarbon Liquids Dissolved CO_2

Any CO_2 that remains entrained in the liquid hydrocarbons after storage tank flashing is lost to the atmosphere during the crude transportation and processing phases.

Hydrocarbon liquids produced through EOR operations may contain small quantities of CO_2 dissolved in the produced oil, which may cause emissions downstream of the storage tank during the transportation and processing of the oil. The amount of CO_2 retained in hydrocarbon liquids after tank flashing at atmospheric pressure can be determined by taking compositional samples that measure the CO_2 retention that is occurring in the oil immediately downstream of the storage tank as shown in Equation 6-26 (EPA, 2019a).

$$E_{CO_2} = S_{h1} \times V_{h1} \qquad \text{(Equation 6-26)}$$

where:

E_{CO_2} = Annual CO_2 emissions from CO_2 retained in hydrocarbon liquids produced through EOR operations beyond tankage (tonnes CO_2/year);

S_{h1} = Amount of CO_2 retained in hydrocarbon liquids downstream of the storage tank, under standard conditions (tonnes CO_2/bbl); and

V_{h1} = Total volume of hydrocarbon liquids produced at the EOR operations (bbl/year).

6.3.10.3 EOR CO_2 Injection Pump Blowdown

EOR operations use compressors or pumps to inject supercritical phase CO_2 into reservoirs. For upsets or maintenance events, these high pressure injection pumps may be blown down to atmospheric pressure, resulting in the release of the supercritical phase CO_2 in the pressurized system between isolation valves. The volume of CO_2 released during such blowdown events can be calculated using the estimated total physical volume between isolation valves (including, but not limited to, pipelines, compressors and vessels) and density of the supercritical phase CO_2 released. The emissions can be calculated using the following equation taken from EPA GHGRP Subpart W, equation W-37 (EPA, 2019a).

$$E_{CO_2} = N \times V_v \times R_c \times GHG_{CO_2} \times 0.001 \qquad \text{(Equation 6-27)}$$

where:

E_{CO_2} = Annual EOR injection pump system emissions from EOR Injection pump blowdowns (tonnes CO_2/yr);
N = Number of blowdowns for the EOR injection pump system (events/year);
V_V = Total physical volume of EOR injection pump system chambers (including pipelines, manifolds, and vessels) between isolation valves (cubic feet or cubic meters);
R_C = Density of EOR injection gas at the supercritical operating temperature and pressure of the injection pump (kg/ft^3 or kg/m^3); and
GHG_{CO_2} = Mass fraction of CO_2 in critical phase injection gas.

An example calculation is shown in Exhibit 6.3-18 for a CO_2 injection pump blowdown event.

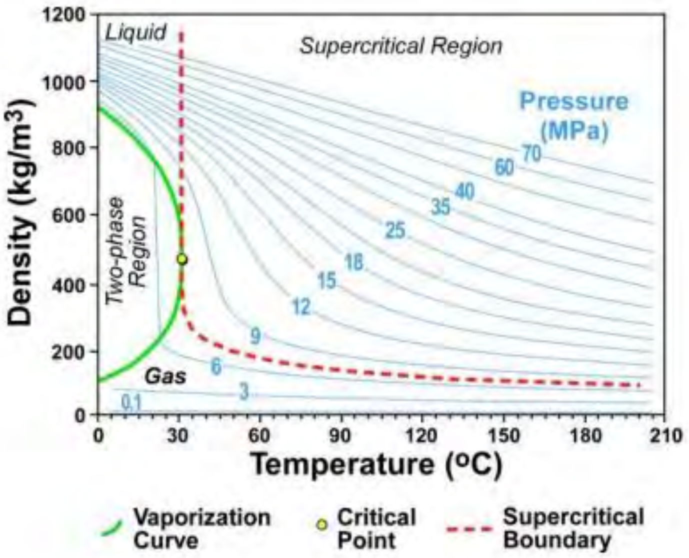
EXHIBIT 6-22: Sample Calculation for CO_2 Venting Emissions from CO_2 EOR Injection Pump Blowdown

INPUT DATA:
In a CO_2 EOR operation, one of the CO_2 injection pumps was blown down for maintenance, releasing CO_2 into the atmosphere to depressurize the system. The following parameters were estimated for the operational conditions of the injection pump:

- Estimated physical volume between isolation valves: 36.4 m^3
- Injected gas composition: 98.5 weight % CO_2
- Pressure of EOR gas at pump discharge prior to release: 2,000 psig (13.79 MPag)
- Temperature of EOR gas at pump discharge prior to release: 60°C

Calculate the vented CO_2 emissions.

CALCULATION METHODOLOGY:
The CO_2 vented emissions are estimated using Equation 6-20. The density of CO_2 is estimated using data showing the relation of the density of CO_2 to temperature and pressure.



Reference: Whittaker, S. et al. 2013. Technical aspects of CO_2 enhanced oil recovery and associated carbon storage.

Based on the CO_2 density diagram above, the approximate density of CO_2 at 14 MPa and 60°C is 650 kg/m^3.

$$E_{CO_2}=\frac{1\text{ blowdown event}}{\text{yr}}\times\frac{36.4\text{ m}^3\text{ gas vented}}{\text{blowdown event}}\times\frac{650\text{ kg gas}}{\text{m}^3\text{gas}}\times\frac{0.985\text{ kg }CO_2}{\text{kg gas}}\times 0.001$$

$$\underline{E_{CO_2}=23\text{ tonne }CO_2/\text{yr}}$$

6.3.11 Other Production Related Venting

Other sources of venting in the production segment may include:

- Well completions and well testing may be conducted in the production segment. Calculation approaches for well completions and well testing are covered in Section 6.2 for the exploration segment;
- Compressor venting, although typically considered part of gathering and boosting, can occur at the wellhead or other production facilities. Calculation approaches for compressor venting are covered in Section 6.4 for the gathering and boosting segment;
- Blowdowns from pipelines and equipment for maintenance activities or emergency conditions. Refer to Section 6.4 for the gathering and boosting segment;
- Well blowouts, while very rare, are unplanned events that may occur in production. Well blowouts result in uncontrolled releases, the emissions from which can be calculated using well test data or production data and duration. Refer to Section 6.2 for the exploration segment;
- Pressure relief valve (PRV) venting (see below); and

- Offshore production venting.

Offshore considerations for venting emissions often coincide with that of onshore. One portion of operational offshore emissions is emissions from non-routine activities; which are the result of unplanned events (such as during emergency or upset conditions) that result in releases of gas (including CH_4, and possibly CO_2) to the atmosphere.

The equation for estimating the emissions of CH_4 or CO_2 from intermittent, non-continuous venting is shown in Equation 6-28:

$$E_x = VR \times F_x \times \frac{MW_x}{\text{molar volume conversion}} \times T_v \times n \qquad \text{(Equation 6-28)}$$

where:

E_x = Emissions of "x" in units of mass (pounds, kg, tonnes) per year;
"x" = GHG compound of interest (CH_4, or CO_2 for CO_2 rich streams);
VR = Vent rate in volume units at STP conditions (scfm or Sm^3/min) per event;
F_x = Molar fraction of compound "x" in the vent gas stream;
MW_x = Molecular weight of compound "x";
Molar volume conversion = Conversion from molar volume to mass (379.3 scf/lbmole or 23.685 Sm^3/kgmole);
T_v = Time duration of the venting event (minutes); and
n = Number of events of this type and magnitude annually.

This equation calculates the total amount of CH_4 or CO_2 released during the event. To estimate an annual emission rate, determine the frequency and duration of such venting episodes on a yearly basis using either documentation from actual venting events or averages from past events.

The GRI/EPA study developed emission factors for facility emergency shut down (ESD) systems at offshore facilities and for PRVs associated with either onshore or offshore production activities. ESDs are manual or automatic safety systems that shut down and vent all rotating equipment when an emergency is detected. The emission factor is based on an average number of ESD blowdowns vented to the atmosphere on an annual basis.

Similarly, the GRI/EPA study developed a PRV emission factor based on the average size and duration of release events at production facilities. The amount of gas released through a PRV is highly dependent on upstream gas pressure and valve size. A more detailed estimation method for PRV releases is provided in Appendix B (CAPP, 2002, Section 3.2.3). Table 6-28 provides default emission factors for other non-routine venting sources from the production segment operations.

Table 6-28. Production Segment CH_4 Emission Factors for Other Non-Routine Releases

Source	Methane Emission Factor [a], Original Units	Methane Emission Factor [b], Converted to Tonnes Basis	Methane Content Basis of Factor (mole %)	Uncertainty [c] (±%)	Whole Gas Emission Factor [d], Converted to Whole Gas Volume Basis
Pressure relief valve releases	34 scfy CH_4/ PRV	0.00065 tonnes/PRV-yr	78.8	310	43 scfy gas/ PRV
Offshore emergency shutdown (ESD)	256,888 scfy CH_4/platform	4.9276 tonnes/ platform-yr	78.8	276	326,000 scfy gas/platform

Footnotes and Sources:

[a] Shires, T.M. *Methane Emissions from the Natural Gas Industry, Volume 7: Blow and Purge Activities*, *Final Report*, GRI-94/0257.24 and EPA-600/R-96-080g, Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[b] CH_4 emission factors converted from scf or m^3 are based on 60°F and 14.7 psia. The CH_4 emission factors can be adjusted based on the relative concentrations of CH_4 and CO_2 to estimate CO_2 emissions.

[c] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[d] Converted using 78.8 mole % CH_4 assumed in the derivation of the CH_4 emission factor.

6.4 Oil and Gas Gathering and Boosting

6.4.1 Gas-Driven Pneumatic Controllers

As in the production segment, natural gas-operated pneumatic controllers are commonly used in gas gathering and boosting systems. Emissions of CH_4 (and CO_2, if present in the gas) from pneumatic controllers located in gathering and boosting systems can be estimated using the same estimation methodologies as those described in Section 6.3.6 for production. If site-specific controller measurements or manufacturer's data is available, the calculation methods presented in Section 6.3.6 can be applied for continuous and intermittent vent controllers, respectively. See Equation 6-12 for estimating the volume of gas vented using controller-specific data from continuous vent pneumatic controllers, and Equations 6-13 or 6-14 for intermittent vent pneumatic controllers.

Alternatively, default emission factors presented by controller type are provided in Table 6-29 below for continuous vent and intermittent vent pneumatic controllers in the gathering and boosting segment. The emission factors from the API working paper presented in Section 6.3.6 represent an integrated assessment of production and gathering and boosting station measurement data. The pneumatic controller emission factors from the API working paper are presented in Tables 6-14 and 6-15 for continuous and intermittent vent controllers, respectively.

The emission factors in Table 6-29 are taken from a study conducted by Colorado State University (Zimmerle, 2019) based on measurements of 72 pneumatic controllers in 16 gathering

Table 6-29. Natural Gas-Driven Pneumatic Controller Emission Factors in Gathering and Boosting

Controller Type	Original Units, Emission Factor (scf gas/ hr/controller) [a]	Uncertainty (± %) [b]	Methane Content Basis of Factor (mole %) [c]	Methane Emission Factor (Converted) (scf CH_4/ controller-hr)	Methane Emission Factor (Converted) (tonnes CH_4/ controller-yr) [d]
Continuous Vent Pneumatic Controllers					
High Bleed	19.25	70	81.6	15.71	2.64
Low bleed, normal operation [e]	0.68	74	81.6	0.55	0.093
Low bleed, malfunctioning [f]	34	61	81.6	27.74	4.66
Low bleed, average (if operating condition is unknown) [g, h]	6.42	74	81.6	5.24	0.88
Intermittent Vent Pneumatic Controllers					
Intermittent, normal operation [e]	2.82	115	81.6	2.30	0.39
Intermittent, malfunctioning [f]	16.11	49	81.6	13.15	2.21
Intermittent, average (if operating condition is unknown) [g, h]	11.13	115	81.6	9.08	1.52
Average Pneumatic Controller, if Controller Type is Unknown					
Gathering and Boosting Average, normal operation [e]	4.98	70	81.6	4.06	0.68
Gathering and Boosting Average, malfunctioning [f]	19.09	40	81.6	15.58	2.61
Gathering and Boosting Average (if operating condition is unknown) [g, h]	9.13	70	81.6	7.45	1.25

Footnotes and sources:

[a] Zimmerle, D, et al. 2019. Multiday Measurements of Pneumatic Controller Emissions Reveal the Frequency of Abnormal Emissions Behavior at Natural Gas Gathering Sites. *Environ. Sci. Technol. Lett. 2019, 6, 348-352.* 10.1021/acs.estlett.9b00158.

[b] Uncertainty based on 95% confidence interval.

[c] Gas content of CH_4 taken from the GHGI Annex 3.6 Table 3.6-3 for U.S. Production sector CH_4 Content in Natural Gas by NEMS Region (General Sources), for the lower 48 states in 2017 (EPA GHGI, 2019). The CH_4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH_4 content from the default basis if given). Also, if the facility gas contains

significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

[d] Annual emission factor based on 8,760 hrs/yr operation.

[e] The normal operation emission factor should be applied to controllers that are found to be operating normally as part of a proactive monitoring and repair program.

[f] The malfunctioning operation emission factor should be applied to controllers that are found to be venting at a higher than expected rate, as discovered from a proactive monitoring and repair program.

[g] Values were calculated using data from the Zimmerle, D., et al. study, weighted by sample size. Sample size for intermittent is 15 normal operation, 25 malfunctioning. Sample size for low bleed is 24 normal operation, 5 malfunctioning. Sample size for average gathering and boosting is 72 normal operation, 30 malfunctioning.

[h] The average emission factor should be used for controllers that are not routinely monitored as part of a proactive monitoring and repair program.

compressor stations in the US. The emission factors are based on whole gas volume; therefore, the corresponding CH_4 emission factors were converted using the production segment average CH_4 content of 81.6 mole % from the GHGI (EPA, 2019b). The CH_4 emission factors can be adjusted based on the CH_4 content of the site-specific gas used as motive gas in the pneumatic controllers if the natural gas is different than the default basis of 81.6 mole %. Also, if the pneumatic controllers are driven with gas that contains significant quantities of CO_2, the CH_4 emission factors can be adjusted based on the relative concentrations of the CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

As shown, the emission factors in Table 6-29 are categorized by controller type and, for the case where controller type is unknown, an average controller type. The emission factors within these controller type categories are further broken down into normal operation, malfunctioning operation, or average operation for cases where no monitoring program is place. (Note that continuous high vent controllers were not categorized into normal and malfunctioning operation.) Further guidance on application of the emission factors is provided below:

- Operations with a proactive monitoring and repair program for pneumatic controllers:
    - Use the normal operation emission factor for controllers that are found to be operating properly as part of a routine monitoring program.
    - Use the malfunctioning operation emission factor for controllers found to be improperly operating as part of a routine monitoring program. The malfunctioning operation emission factor would be applied for the period prior to a confirmed repair, akin to leak/no-leak factors applied to fugitive components (US EPA, 1995).
- Operations without a proactive monitoring and repair program for pneumatic controllers:
    - Use the average operation emission factor
    - Note that for emission reductions from pneumatic controllers to be quantified using emission factors, a routine monitoring and repair program is necessary to demonstrate that controllers are operating normally.

For controllers that are part of a monitoring and repair program, the total CH_4 emissions may be estimated based on the amount of time the controller was operating normally or malfunctioning using the repair date information collected in a monitoring program. This approach for estimation is provided in Equation 6-14, and an example calculation for production is provided in Exhibit 6-12.

To illustrate the use of the emission factors provided for gathering and boosting in Table 6-29, an example calculation is provided below in Exhibit 6-23 that demonstrates the use of the pneumatic controller emission factors.

EXHIBIT 6-23: Sample Calculation for Gas-Driven Pneumatic Controller Emissions

INPUT DATA:
A gathering booster station facility has 80 natural gas-driven pneumatic controllers. The average CH_4 content of the gas is 70 mole %. There is also 9 mole % CO_2 in the gas, so CO_2 emissions from the pneumatic controllers are also relevant. At the gathering and boosting station, the monitoring and repair program does not currently include screening of natural gas-operated pneumatic controllers. Calculate the CH_4 and CO_2 emissions.

CALCULATION METHODOLOGY:
Emissions are calculated by multiplying the number of pneumatic controllers by the emission factor from Table 6-29. The average pneumatic controller emission factors for gathering and boosting are appropriate for use since the type of controllers is not known. Further, since there is no pneumatic controller monitoring and reporting program at the booster station, the average operation emission factor is selected.

The average pneumatic controller CH_4 emission factor is also adjusted from the default basis of 81.6 mole % CH_4 to the site-specific basis of 70 mole % CH_4. Because the gas contains a significant quantity of CO_2, emissions of CO_2 are also estimated using the whole gas factor and the concentration of CO_2 in the gas.

$$E_{CH_4} = 80 \text{ pneumatic controller} \times \frac{7.45 \text{ scf } CH_4}{\text{hr-controller}} \times \frac{70 \text{ mole \% } CH_4}{81.6 \text{ mole \% } CH_4} \times \frac{\text{lbmole } CH_4}{379.3 \text{ scf } CH_4} \times \frac{16 \text{ lb } CH_4}{\text{lbmole } CH_4} \times \frac{\text{tonne } CH_4}{2204.62 \text{ lb } CH_4} \times \frac{8760 \text{ hr}}{\text{yr}}$$

$$\underline{E_{CH_4} = 85.7 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2} = 80 \text{ pneumatic controller} \times \frac{9.13 \text{ scf gas}}{\text{hr-controller}} \times \frac{0.09 \text{ scf } CO_2}{1 \text{ scf gas}} \times \frac{\text{lbmole } CO_2}{379.3 \text{ scf } CO_2} \times \frac{44 \text{ lb } CO_2}{\text{lbmole } CO_2} \times \frac{\text{tonne } CO_2}{2204.62 \text{ lb } CO_2} \times \frac{8760 \text{ hr}}{\text{yr}}$$

$$\underline{E_{CO_2} = 30.3 \text{ tonnes } CH_4/\text{yr}}$$

6.4.2 Gas-Driven Pneumatic Pumps

Emissions from gas driven pneumatic pumps located in gathering and boosting systems can be estimated using the same estimation methodologies and emission factors as those described in

Section 6.3.7 for production. See Equation 6-15 and Equation 6-16, as well as emission factors listed in Table 6-16.

6.4.3 Compressor Venting

In natural gas upstream and midstream segments, compressors are commonly used to increase natural gas pressure in pipelines and production operations. Vented emissions from compressors occur from wet seals and dry seals in centrifugal compressors or rod packing surrounding the mechanical compression components in reciprocating compressors. Compressors are a source of vented emissions of CH_4 during normal operation and during standby mode when the compressor is pressurized and gas escapes through the seals.

In the gathering and boosting sector, reciprocating compressors are the primary compressors used in onshore operations. Therefore, reciprocating compressor venting is discussed in this section whereas centrifugal compressor venting is discussed in Section 6.5 for gas processing.

Compressors are also a source of fugitive emissions from leakage across the compressor blowdown valve when the compressor is pressurized (i.e., leakage across the closed blowdown valve) or isolation valves when the compressor is depressurized and the blowdown valve is open (i.e., leakage from the closed suction and discharge isolation valves). These fugitive emission sources are covered in Section 7 under fugitive emissions from compressors.

6.4.3.1 Reciprocating Compressor Venting

Vented emissions from reciprocating compressors results from gas escaping through the rod packing, a series of flexible rings that surround the piston rod and act as a seal to limit the release of compressed natural gas. Although the rod packing is designed to prevent leakage, small amounts of natural gas slip out from around the rod packing when the compressor is pressurized in either operating mode when the piston is moving or in pressurized, standby mode. The amount of gas passing through the rod packing is a function of the cylinder pressure, alignment and wear on the packing based on hours of operation.

Direct measurement is the most accurate way to determine venting losses from reciprocating compressor venting as set out in the CCAC Technical Guidance Document Number 4: Reciprocating Compressors (CCAC, 2017c). In the absence of measurement data, default CH_4 emission factors can be used to quantify the vented emissions from reciprocating compressor rod packing seals.

Default emission factors are provided in Table 6-30 are based on a recent measurement study of CH_4 emissions from gathering and boosting stations in the US (Zimmerle, 2019), which includes compressor venting emission factors for not only compressor rod packing, but also blowdown vent, pocket vent on each cylinder, and a common single-unit vent.

In addition, default emission factors for rod packing venting are provided from production operations in Canada based on a measurement program in Alberta are provided (Clearstone Engineering, 2018). For comparison, default emission factors are also provided from EPA's GHGRP which provides default emission factors for CH_4 emitted from the rod packing on reciprocating compressors during normal operation in the production and gathering and boosting segments. These EPA GHGRP factors are derived from the GRI/EPA study (Hummel et al, 1996). See below for emission factors from the GHGRP (EPA, 2019a).

Table 6-30. Emission Factors for Compressor Rod Packing in the Gathering and Boosting and Production Segments

Source	Original Units, Emission Factor	Uncertainty [a] (± %)	Methane Content Basis of Factor (mole %)	Methane Emission Factor (Converted) [b] (tonnes CH_4/ compressor-hr)	Whole Gas Emission Factor (Converted) [b] (scf gas/ compressor-hr)
Compressor Rod Packing					
Compressor Rod Packing – US [c]	28.4 scf whole gas/hr/ compressor	21	81.6 [d]	$4.43x10^{-4}$	28.4
Compressor Rod Packing – US GHGRP [e,f]	9.48×10^3 scf CH_4/year-compressor	85	78.8 [g]	$2.07x10^{-5}$	1.37
Compressor Rod Packing - Alberta, Canada [h,i]	0.28745 m^3 THC/hr/ compressor	88	81.6 [d]	$1.39x10^{-4}$	10.2

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval.

[b] Assumes 8.760 hours/yr operation in pressurized mode.

[c] Zimmerle, et al. *Characterization of Methane Emissions from Gathering Compressor Stations: Final Report*, DE-PE0029068, 2019.

[d] Note that the original CH_4 emission factor was converted to whole gas assuming 81.6 mole % CH_4 in natural gas, according to GHGI (EPA, 2019b).

[e] US Environmental Protection Agency (USEPA), 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Data reported as of August 4, 2019. https://ecfr.io/Title-40/sp40.23.98.w. These emission factors are based on EPA/GRI. *Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks*. Table 4-8, "Compressor Seal." Pg 39. 1996. https://www.epa.gov/sites/production/files/2016-08/documents/8_equipmentleaks.pdf.

[f] Confidence interval converted from 90% in original data set to 95%.

[g] The original CH_4 emission factor from the EPA/GRI study was based on 78.8 mole % CH_4 in natural gas from the original study. Therefore, 78.8 mole % CH_4 composition should be used to adjust the emission factor to a different CH_4 content.

[h] Clearstone Engineering, *Technical Report: Update of Equipment, Component and Fugitive Emission Factors for Alberta Upstream Oil and Gas*, prepared for Alberta Energy Regulator, June 10, 2018.

[i] Default emission factors are based on m^3 THC at conditions of 15°C and 1 atm. Total hydrocarbon (THC) content of gas is assumed to be 100% (i.e., no appreciable inerts).

Gathering and boosting or production facilities can calculate GHG emissions from reciprocating compressor rod packing venting using Equation 6-29 below. This is based on the GHGRP Equation W-29D, with the inclusion of the average time that reciprocating compressors are in pressurized mode (EPA, 2019a).

$$E_x = \left(n \times EF_x \times T_{pressurized}\right) \qquad \text{(Equation 6-29)}$$

where:

E_x = Emissions of "x" in units of mass (pounds, kg, tonnes) per year;

"x" = GHG compound of interest (CH_4, or CO_2 for CO_2 rich streams);
n = Number of reciprocating compressors;
EF_x = GHG emission factor for reciprocating compressor rod packing in normal operation (tonnes GHG/compressor-hr); and
$T_{pressurized}$ = Average time during the year that reciprocating compressors are in normal operation or standby, pressurized mode (hrs/yr).

An example calculation is given in Exhibit 6-24 that illustrates the use of reciprocating compressor rod packing emission factors.

EXHIBIT 6-24: Sample Calculation for Reciprocating Compressor Emissions

INPUT DATA:

A gas gathering and boosting facility in the United States has 4 reciprocating compressors. On average, the reciprocating compressors are in normal operation or standby, pressurized mode for 8,470 hours in the reporting year. The average CH_4 content of the gas is 70 mole %. There is also 9 mole % CO_2 in the gas. Calculate the CH_4 and CO_2 emissions from the compressors during normal operation using the EPA GHGRP emission factor.

CALCULATION METHODOLOGY:

Emissions are calculated by multiplying the number of reciprocating compressors by the EPA GHGRP rod packing emission factor for CH_4. Using Equation 6-29, CH_4 and CO_2 emissions from the compressors can be calculated. The GHGRP CH_4 emission factor is also adjusted from the default basis (78.8 mole % CH_4) to the site-specific basis of 70 mole % CH_4. Because the gas contains a significant quantity of CO_2, emissions of CO_2 are also estimated using the relative CO_2 and CH_4 contents in the gas. Emissions are calculated as shown below:

$$E_{CH_4} = (4 \text{ reciprocating compressors}) \times \frac{2.07\times10^{-5} \text{ tonnes } CH_4}{\text{compressor-hr}} \times \frac{8{,}470 \text{ hrs}}{\text{yr}} \times \frac{70 \text{ mole \% } CH_4}{78.8 \text{ mole \% } CH_4}$$

$$\underline{E_{CH_4} = 0.62 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2} = (4 \text{ reciprocating compressors}) \times \frac{1.37 \text{ scf gas}}{\text{compressor-hr}} \times \frac{\text{lbmol}}{379.3 \text{ scf}} \times \frac{0.09 \text{ lb mole } CO_2}{\text{lb mole gas}} \times \frac{44 \text{ lb } CO_2}{\text{lbmol } CO_2}$$

$$\times \frac{\text{tonne}}{2204 \text{ lb}} \times \frac{8{,}470 \text{ hrs}}{\text{yr}}$$

$$\underline{E_{CO_2} = 0.22 \text{ tonnes } CO_2/\text{yr}}$$

6.4.4 Gas Treatment Processes

6.4.4.1 Glycol Dehydration

Emissions from glycol dehydrators located in gathering and boosting can be estimated using the same estimation methodologies and emission factors as those described in Section 6.3.8.1 for production and Section 6.5.2.1 for processing. See emission factors listed in Table 6-17, Table 6-18, and Table 6-35.

6.4.4.2 Desiccant Dehydration

Desiccant dehydrator systems are fully enclosed and therefore, emissions only occur when the vessel is opened to change out the desiccant tablets. The emissions from these desiccant dehydrators can be estimated using the same estimation methodologies listed in Section 6.3.8.2 for desiccant dehydrators used in production. See Equation 6-17 for calculation of emissions.

6.4.4.3 Acid Gas Removal/Sulfur Recovery Units

Emissions from AGRs/SRUs located in gathering and boosting can be estimated using the same estimation methodologies and emission factors as those described in Section 6.3.8.4 for production. See Equation 6-18 and Equation 6-19, as well as emission factors listed in Table 6-19.

6.4.5 Storage Tank Emissions

Emissions from storage tanks in the gathering and boosting segment can be estimated using the same methodologies as those described in Section 6.3.9. Many storage tanks at central tank batteries or booster compressor stations may be receiving unstabilized crude or condensate, with flashing losses contributing to tank emissions. Other tanks may be receiving stabilized crude or condensate, meaning that flashing may have already occurred upstream at the production pad and emissions will be attributed to working and standing losses. Gathering and boosting storage tank flashing, working and standing losses can be estimated using the same approaches presented in Section 6.3.9 for the production segment.

In the absence of site-specific data to quantify CH_4 emissions from storage tanks in gathering and boosting, default emission factors may be used. Table 6-31 presents whole gas and CH_4 emission factors based on a measurement program conducted at boosting compressor stations in the US (Zimmerle, 2019). ‘For uncontrolled tanks, tank vents are primarily used to vent flash gas from liquids in the tank. However, leaks in upstream equipment, such as dump valves on separators, may malfunction and leak gas that is eventually routed to, and emitted from, tank vents’ (Zimmerle, 2019). The average storage tank emission factor in Table 6-31 should be used for CH_4 emissions from storage tanks in gathering and boosting stations when data to support other methods is unavailable. The average emission factor for common single unit vent can be applied when the number of vents per tank is known; however, the emission factor for venting through the tank thief hatch would also need to be applied to estimate total vented emissions from a tank.

Table 6-31. Emission Factors for Storage Tanks in the Gathering and Boosting Segment

Source	Original Units, Whole Gas Emission Factor [a]	Whole Gas Emission Factor Uncertainty [b] (± %)	Methane Emission Factor [c]	Methane Emission Factor Uncertainty [b] (± %)
Average Storage Tank in Gathering and Boosting	39.3 scf gas/hr/tank[e]	130	33.6 scf CH_4 /hr/tank[f]	134
Common Single Unit Vent [d]	9.21 scf gas/hr/vent	47	8.52 scf CH_4/hr/vent	44
Thief Hatch	9.85 scf gas/hr/tank	28	8.77 scf CH_4/hr/vent	30

Footnotes and Sources:

[a] Zimmerle, et al. *Characterization of Methane Emissions from Gathering Compressor Stations: Final Report*, Table 4, DE-PE0029068, 2019.

[b] Uncertainty based on 95% confidence interval.

[c] Zimmerle, et al. *Characterization of Methane Emissions from Gathering Compressor Stations: Final Report*, Table 5, DE-PE0029068, 2019.

[d] As reported, most tanks have several vents or outlets that vent directly to the atmosphere (Zimmerle, 2019). Use of this factor is only applicable when the total vents per tank is known. Note that the thief hatch emission factor would also need to be applied to quantify total emissions from a storage tank.

[e] Zimmerle, et al. *Methane Emissions from Gathering and Boosting Compressor Stations in the U.S.: Supporting Volume 3: Emission Factors, Station Estimates, and National Emissions*. October 2019 Revision. Table S3-41.

[f] Zimmerle, et al. *Methane Emissions from Gathering and Boosting Compressor Stations in the U.S.: Supporting Volume 3: Emission Factors, Station Estimates, and National Emissions*. October 2019 Revision. Table S3-42.

6.4.6 Other Gathering and Boosting-Related Venting Emissions

6.4.6.1 Equipment and Process Blowdowns

Equipment blowdowns often take place prior to maintenance activities or as a result of emergency conditions. This typically results in the depressurization of equipment to evacuate the accumulated gas so maintenance or other activities can be performed. Equipment that is frequently blown down in the gathering and boosting segment includes (but is not limited to) compressors, process vessels (including separators, dehydrators, and in-line heaters), pipelines, and pig launchers or receivers.

Emissions from blowdowns can generally be estimated by the following equation:

$$E_{CH_4 \text{ or } CO_2} = \frac{\text{Gas Volume Released}}{\text{Event}} \times \text{Mole \%}_{CH_4 \text{ or } CO_2} \times \frac{\#\text{Events}}{\text{Year}} \times \frac{MW_{CH_4 \text{ or } CO_2}}{\text{molar volume conversion}}$$

(Equation 6-30)

where:

$E_{CH_4 \text{ or } CO_2}$ = Emissions of CH_4 or CO_2 emissions in units of mass (e.g, lb or kg);

Gas Volume Released = Volume of gas released during the blowdown event, in standard conditions (e.g., scf @ 60°F and 14.7 psia or sm^3 @ 15°C and 1 atm)
$MW_{CH4\ or\ CO2}$ = Molecular weight of CH_4 or CO_2; and
Molar volume conversion = Conversion from molar volume to mass (379.3 scf/lbmole or 23.685 Sm^3/kgmole).

Engineering assumptions based on equipment design specifications for the vessel/pipeline/equipment of interest may be required to estimate the volume of gas released, which is listed in Equation 6-31 below. For example, the volume released may be based on the internal volume of a piece of equipment or the volume contained between isolation valves within a pipe section (assuming the entire contents are released).

In the absence of such design data, the CAPP document, *Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities*, provides guidance on estimating the volumes for several vessel types (CAPP, 2002, Section 3.2.4). These vessel types include horizontal and vertical cylinders, and hemispherical and ellipsoidal end caps. Standard engineering equations for estimating internal volumes may be applied and are described in the CAPP document referenced above. The CAPP document also provides volumes per meter of pipeline length for several pipe sizes and schedules (CAPP, 2002, Table 3-8). These volumes are provided in Appendix B.

The volume estimated using physical equipment dimensions represents the volume of gas at actual temperature and pressure conditions at the process conditions before the blowdown event. The actual volume of gas must be converted to standard conditions to use in Equation 6-30 (i.e., the gas must be converted from actual cubic feet of gas (at actual temperature and pressure) to standard cubic feet (at standard temperature and pressure) using the ideal gas law (see Section 3.5, Equation 3-4). Note that at high pressure conditions, the gas may not behave as an ideal gas and the compressibility factor term in the gas law should be used to estimate the moles of gas, as shown in Equation 6-31 below.

$$PV = znRT \qquad \text{(Equation 6-31)}$$

where:

P = Pressure (psia or atm);
V = Volume;
z = Compressibility factor, tables for CH_4 and CO_2 are provided in *Perry's Chemical Engineer's Handbook*, Tables 3-172 and 3-166, respectively (Perry, 1984);
n = Number of moles;
R = Gas constant; and
T = Absolute temperature (°R or K).

Rearranging the ideal gas law, the equation to estimate moles of gas in the actual volume vented becomes:

$$n = \frac{PV}{zRT} \qquad \text{(Equation 6-32)}$$

Using this equation, the moles of gas emitted can be converted to a mass basis by applying the molecular weight of CH_4 or CO_2 as shown in Equation 6-33.

$$E_{CH_4 \text{ or } CO_2} = \frac{\text{Moles Gas Released}}{\text{Event}} \times \text{Mole\%}_{CH_4 \text{ or } CO_2} \times MW_{CH_4 \text{ or } CO_2} \times \frac{\#\text{Events}}{\text{Year}} \qquad \text{(Equation 6-33)}$$

For gas pipeline pigging operations, the volume released would be based on the segment of pipeline depressurized plus the volume of the pig catcher or launcher. Note that emissions associated with unstabilized oil pipeline pigging operations should be calculated in a manner similar to emissions from crude tank flashing, which is described in Section 6.3.9.1 for Flashing Losses from Unstabilized Crude and Condensate Storage Tanks.

An example of this approach is demonstrated in Exhibit 6-25.

EXHIBIT 6-25: Sample Calculation for Estimating Equipment Blowdown Emissions

INPUT DATA:

The volume of gas vented from a vessel (e.g., a separator) must take into account whether or not the fluids contained within the vessel will need to be removed to perform the desired maintenance activity. For example, a low pressure separator, operating at 100 psig and ambient temperature (~80 °F), that is blown down to replace a gauge or a relief valve will likely leave the fluid levels intact and remove only the gas. The vessel dimensions are 4 ft in diameter and 10 ft long. The gas composition in the separator is 90% CH_4 with no CO_2. Calculate the CH_4 emissions assuming that the liquid volume occupies 1/3 of the vessel.

CALCULATION METHODOLOGY:

The first step in calculating emissions is to calculate the total volume (V_T) of the vessel in the separator. The actual volume is estimated based upon the internal dimensions:

$$V = \pi r^2 L = \pi \times \left(\frac{4\text{ft}}{2}\right)^2 \times 10 \text{ ft (actual)} = 125.7 \text{ ft}^3 \text{(actual)}$$

The volume of gas (VG) released is a fraction of this total volume as defined by:

$$V_G = V_T - \left(\frac{1}{3} \times V_T\right) = 125.7 \text{ ft}^3 - \left(\frac{1}{3} \times 125.7 \text{ ft}^3\right) = 83.8 \text{ ft}^3 \text{ (estimated)}$$

The moles of gas released is then calculated using Equation 6-32. The compressibility factor for CH_4 is determined to be 0.9864 (Perry, 1984).

$$n = \frac{(100 \text{ psig} + 14.7) \times \left(83.8 \text{ ft}^3\right)}{0.9864 \times 10.73 \dfrac{\text{psi ft}^3}{\text{lbmole } ^\circ\text{R}} \times 539.7 \ ^\circ\text{R}} = 1.68 \text{ lbmoles gas/blowdown event}$$

Finally, the CH_4 emissions are calculated using Equation 6-33:

$$E_{CH_4} = \frac{1.68 \text{ lbmoles gas}}{\text{blowdown event}} \times \frac{0.9 \text{ lbmoles } CH_4}{\text{lbmoles gas}} \times \frac{16 \text{ lb } CH_4}{\text{lbmole } CH_4} \times \frac{1 \text{ blowdown}}{\text{yr}} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CH_4} = 0.011 \text{ tonne } CH_4/\text{yr}}$$

Use of the gas law is most appropriate for situations where the entire volume of the vessel is blown down and the volume of gas released is finite. More rigorous engineering approaches are needed for a blowdown situation where only a portion of the vessel contents is released.

When no specific equipment information is available, simplified CH_4 emission factors from certain types of equipment blowdown activities from Table 6-32 may be applied to estimate emissions. The majority of these emission factors are taken from the GRI/EPA study (Shires, 1996b).

Table 6-32. Gathering Segment CH_4 Emission Factors for Certain Blowdown Activities

Source	Original Units, Methane Emission Factor [a]	Uncertainty [b] (± %)	Methane Emission Factor, Converted to Tonnes Basis	Methane Content Basis of Factor (mole %)	Whole Gas Emission Factor (Converted) [c]
Vessel blowdowns	78 scf CH_4/yr-vessel	326	0.0015 tonnes/vessel-yr	78.8	99 scf gas/yr-vessel
Compressor blowdowns	3,774 scf CH_4/yr-compressor	179	0.07239 tonnes/compressor-yr	78.8	4,789 scf gas/yr-compressor
Gathering gas pipeline blowdowns	309 scf CH_4/yr-mile	39.5	0.00593 tonnes/mile-yr 0.00368 tonne/km-yr	78.8	392 scf gas/yr-mile

Footnotes and Sources:

[a] Shires, T.M. *Methane Emissions from the Natural Gas Industry, Volume 7: Blow and Purge Activities*, *Final Report*, GRI-94/0257.24 and EPA-600/R-96-080g, Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[b] Uncertainty based on a 95% confidence interval.
[c] Converted assuming 78.8 mole % CH_4 in the gas used in the EPA/GRI study.

An example calculation is given in Exhibit 6-26 below that illustrates the use of the production segment maintenance/turnaround-related emission factors.

EXHIBIT 6-26: Sample Calculation for Equipment Blowdown Emissions

INPUT DATA:
A gas production field has 10 low-pressure gas wells that send produced gas through 5 miles of gathering pipeline. The field also has five process vessels and a compressor. The gas contains 70 mole % CH_4 and 8 mole % CO_2. Calculate the blowdown vented emissions, by activity.

CALCULATION METHODOLOGY:
The equipment count for each maintenance related activity (vessel blowdowns, compressor blowdowns, and gathering pipeline blowdowns) is multiplied by the appropriate emission factor from Table 6-32. The emission factors are corrected by the ratio of the site CH_4 content to the emission factor default CH_4 content. CO_2 emissions are also estimated to account for the CO_2 content of the gas. CO_2 emissions are determined by using the whole gas emission factor and adjusting for the concentration of CO_2 in the gas.

Emissions are calculated below, by maintenance activity.

Vessel blowdowns:

$$E_{CH_4} = 5 \text{ vessels} \times \frac{78 \text{ scf } CH_4}{\text{year-vessel}} \times \frac{70 \text{ mole \% } CH_4}{78.8 \text{ mole \% } CH_4} \times \frac{\text{lbmole } CH_4}{379.3 \text{ scf } CH_4} \times \frac{16 \text{ lb } CH_4}{\text{lbmole } CH_4} \times \frac{\text{tonne}}{2204.62 \text{ lb } CH_4}$$

$$\underline{E_{CH_4} = 0.007 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2} = 5 \text{ vessels} \times \frac{99 \text{ scf gas}}{\text{year-vessel}} \times \frac{0.08 \text{ scf } CO_2}{1 \text{ scf gas}} \times \frac{\text{lbmole } CO_2}{379.3 \text{ scf } CO_2} \times \frac{44 \text{ lb } CO_2}{\text{lbmole } CO_2} \times \frac{\text{tonne}}{2204.62 \text{ lb } CO_2}$$

$$\underline{E_{CO_2} = 0.002 \text{ tonnes } CO_2/\text{yr}}$$

Compressor blowdowns:

$$E_{CH_4} = 1 \text{ compressor} \times \frac{3{,}774 \text{ scf } CH_4}{\text{year-compressor}} \times \frac{70 \text{ mole \% } CH_4}{78.8 \text{ mole \% } CH_4} \times \frac{\text{lbmole } CH_4}{379.3 \text{ scf } CH_4} \times \frac{16 \text{ lb } CH_4}{\text{lbmole } CH_4} \times \frac{\text{tonne}}{2204.62 \text{ lb } CH_4}$$

$$\underline{E_{CH_4} = 0.064 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2} = 1 \text{ compressor} \times \frac{4{,}789 \text{ scf gas}}{\text{year-compressor}} \times \frac{0.08 \text{ scf } CO_2}{1 \text{ scf gas}} \times \frac{\text{lbmole } CO_2}{379.3 \text{ scf } CO_2} \times \frac{44 \text{ lb } CO_2}{\text{lbmole } CO_2} \times \frac{\text{tonne}}{2204.62 \text{ lb } CO_2}$$

$$\underline{E_{CO_2} = 0.020 \text{ tonnes } CO_2/\text{yr}}$$

Gathering pipeline blowdowns:

$$E_{CH_4} = 5 \text{ miles} \times \frac{309 \text{ scf } CH_4}{\text{year-mile}} \times \frac{70 \text{ mole \% } CH_4}{78.8 \text{ mole \% } CH_4} \times \frac{\text{lbmole } CH_4}{379.3 \text{ scf } CH_4} \times \frac{16 \text{ lb } CH_4}{\text{lbmole } CH_4} \times \frac{\text{tonne}}{2204.62 \text{ lb } CH_4}$$

$$\underline{E_{CH_4} = 0.026 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2} = 5 \text{ miles} \times \frac{392 \text{ scf gas}}{\text{year-mile}} \times \frac{0.08 \text{ scf } CO_2}{1 \text{ scf gas}} \times \frac{\text{lbmole } CO_2}{379.3 \text{ scf } CO_2} \times \frac{44 \text{ lb } CO_2}{\text{lbmole } CO_2} \times \frac{\text{tonne}}{2204.62 \text{ lb } CO_2}$$

$$\underline{E_{CO_2} = 0.008 \text{ tonnes } CO_2/\text{yr}}$$

6.4.6.2 *Other Gathering and Boosting-Related Venting Emissions*

A summary of the CH_4 emission factors from other gathering and boosting segment venting releases is given in Table 6-33.

The GRI/EPA study developed a PRV emission factor based on the average size and duration of release events at production facilities. The amount of gas released through a PRV is highly dependent on upstream gas pressure and valve size. A more detailed estimation method for PRV releases is provided in Appendix B (CAPP, 2002, Section 3.2.3).

Dig-ins of gathering gas lines in production are unintentional mishaps that result in gas being released to the atmosphere. Gathering crude pipelines may emit CH_4, entrained in the crude at pipeline pressure, but dig-in or leak emission factors for these pipelines are not readily available.

Compressor starts are vented emissions of the natural gas used to start the engine. If the compressor is started with air, there would be no CH_4 emissions from this activity. Compressor blowdowns occur when the compressor is depressurized to the atmosphere when it is shutdown.

The oil pump station emission factor is based on an estimate of annual maintenance activities and an assumed CH_4 content of 100 ppm in the crude (Tilkicioglu et al, 1989).

These non-routine activities are the result of unplanned events (such as during emergency or upset conditions) that result in releases of gas (including CH_4, and possibly CO_2) to the atmosphere. All of the emission factors given in Table 6-33 are provided on an equipment (or facility) count basis.

Table 6-33. Gathering Segment Emission Factors for Other Non-Routine Releases

Source	Original Units, Methane Emission Factor	Uncertainty [a] (±%)	Methane Emission Factor, Converted to Tonnes Basis	Methane Content Basis of Factor (mole %)	Whole Gas Emission Factor (Converted)
Pressure relief valves releases [b]	34 scf CH_4/year-PRV	310	0.00065 tonnes CH_4/PRV-yr	78.8	43 scf/yr-PRV
Gathering gas pipeline mishaps (dig-ins) [b]	669 scf/year-mile	2,350	0.0128 tonnes CH_4/mile-yr	78.8	849 scf/yr-mile
			0.00797 tonnes CH_4/km-yr		527 scf/yr-km
Compressor starts [c]	8,443 scf/year-compressor	190	0.16 tonnes CH_4/year-compressor	78.8	10,714 scf/yr-compressor
Oil pump stations (maintenance) [d]	1.56 lb/yr-station	Not available	0.00071 tonnes CH_4/year-station	78.8	46.9 scf/yr-station

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Shires, T.M. *Methane Emissions from the Natural Gas Industry, Volume 7: Blow and Purge Activities*, *Final Report*, GRI-94/0257.24 and EPA-600/R-96-080g, Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[c] An EPA Gas STAR paper on engine starts reports that typical production compressor engine start-ups vent 1,000 to 5,000 scf of gas with each start-up attempt (EPA Gas STAR, PRO Fact Sheet No. 101, September 2004). This equates to 0.015 to 0.076 tonnes CH_4/start-up attempt assuming 78.8 mole % CH_4 in the gas.

[d] Tilkicioglu, B.H and D.R. Winters. *Annual Methane Emission Estimate of the Natural Gas and Petroleum Systems in the United States*. Pipeline Systems Incorporated (PSI), December 1989.

An example calculation is given below in Exhibit 6-27 that illustrates the use of emission factors from other production segment non-routine emission sources.

EXHIBIT 6-27: Sample Calculation for Other Gathering and Boosting Segment Non-routine Emission Sources

INPUT DATA:

An oil and gas company has the following non-routine events occur during the calendar year associated with a gathering and boosting operation:

- 6 PRV releases;
- 1 compressor start (using natural gas to start the compressor);
- 6 miles of affected by pipeline dig-in events; and
- 1 maintenance event at an oil pump station.

The site gas has 79 mole % CH_4 content and no CO_2. Calculate the non-routine emissions by activity.

CALCULATION METHODOLOGY:

The PRV release events and miles of gathering pipeline affected by dig-in events are each multiplied by the appropriate emission factor from Table 6-33. The CH_4 emission factors are not corrected by the site CH_4 content because it is similar to the default concentration associated with the emission factors. Emissions are calculated below, by activity.

PRV releases:

$$E_{CH_4} = 6 \text{ PRV events} \times \frac{34 \text{ scf CH}_4}{\text{year-PRV}} \times \frac{\text{lbmole CH}_4}{379.3 \text{ scf CH}_4} \times \frac{16 \text{ lb CH}_4}{\text{lbmole CH}_4} \times \frac{\text{tonne}}{2204.62 \text{ lb CH}_4}$$

$$\underline{E_{CH_4} = 0.0039 \text{ tonnes CH}_4/\text{yr}}$$

Gathering gas pipeline mishaps (Dig-ins):

$$E_{CH_4} = 6 \text{ miles} \times \frac{669 \text{ scf CH}_4}{\text{year-mile}} \times \frac{\text{lbmole CH}_4}{379.3 \text{ scf CH}_4} \times \frac{16 \text{ lb CH}_4}{\text{lbmole CH}_4} \times \frac{\text{tonne}}{2204.62 \text{ lb CH}_4}$$

$$\underline{E_{CH_4} = 0.077 \text{ tonnes CH}_4/\text{yr}}$$

Compressor starts:

$$E_{CH_4} = 1 \text{ compressor start} \times \frac{8{,}443 \text{ scf CH}_4}{\text{year-compressor start}} \times \frac{\text{lbmole CH}_4}{379.3 \text{ scf CH}_4} \times \frac{16 \text{ lb CH}_4}{\text{lbmole CH}_4} \times \frac{\text{tonne}}{2204.62 \text{ lb CH}_4}$$

$$\underline{E_{CH_4} = 0.16 \text{ tonnes CH}_4/\text{yr}}$$

Oil Pump Stations (maintenance):

$$E_{CH_4} = 1 \text{ oil pump station maintenance event} \times \frac{0.00071 \text{ tonnes CH}_4}{\text{year-station}}$$

$$\underline{E_{CH_4} = 0.00071 \text{ tonnes CH}_4/\text{yr}}$$

6.5 Natural Gas Processing

6.5.1 Natural Gas-driven Pneumatic Controllers and Pumps

While many gas processing plants rely on compressed air to power pneumatic controllers, natural gas may be used in limited situations such as isolation valves for emergency shut down or maintenance. Emissions of CH_4 (and CO_2, if present in the gas) from pneumatic controllers located in gas processing plants can be estimated using the same estimation methodologies as those described in Section 6.3.6 for production. If site-specific pneumatic controller measurements or manufacturer's data is available, the calculation methods presented in Section 6.3.6 can be applied for continuous and intermittent vent pneumatic controllers, respectively. See Equation 6-12 for estimating the volume of gas vented using controller-specific data from continuous vent pneumatic controllers, and Equations 6-13 or 6-14 for intermittent vent pneumatic controllers.

Alternatively, default emission factors presented by type of pneumatic controller are provided in Table 6-34. The processing segment pneumatic controller emission factors in Table 6-34 are primarily taken from the 1996 GRI/EPA report (Volumes 2 and 12) (Harrison, 1996; Shires, 1996). The average processing pneumatic controller emission factor on a throughput basis is derived from estimated processing pneumatic controllers' vented CH_4 emissions (Harrison, et al., Vol 2, 1996) and estimated annual gas processed (DOE, 1993).

The emission factors are presented in both original units and converted to CH_4 and whole gas basis, respectively, using the processing segment average CH_4 content of 86.8 mole % from the 1996 GRI/EPA study. The CH_4 emission factors can be adjusted based on the CH_4 content of the site-specific gas used as motive gas in the pneumatic controllers if the natural gas is different than the default basis of 86.8 mole %. Also, if the pneumatic controllers are driven with gas that contains significant quantities of CO_2, the CH_4 emission factors can be adjusted based on the relative concentrations of the CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

Table 6-34. Gas-Driven Pneumatic Controller CH_4 Emission Factors in Gas Processing Segment

Pneumatic Controller Type	Emission Factor [a], Original Units	Uncertainty [b] (±%)	Methane Emission Factor [c], Converted to Tonnes Basis	Methane Content Basis (mole %)	Whole Gas Emission Factor, Converted [d]
Continuous bleed	497,584 scf gas/controller-yr	35.5	8.304 tonnes CH_4/controller-yr	86.8	56.8 scf gas/ controller-hr
Piston valve operator	48 scf gas/controller-yr	60.9	8.010×10^{-4} tonnes CH_4/controller-yr		5.48×10^{-3} scf gas/ controller-hr
Pneumatic/hydraulic valve operator	5,627 scf gas/controller-yr	134	0.0939 tonnes CH_4/controller-yr		6.42×10^{-1} scf gas/ controller-hr
Turbine valve operator	67,599 scf gas/controller-yr	407	1.128 tonnes CH_4/controller-yr		7.72 scf gas/ controller-hr
Processing average (if controller type is unknown)	*164,949 scf CH_4/plant-yr*	*170*	*3.164 tonnes CH_4/plant-yr*		*190,033 scf gas/ plant-yr*
	7.431 scf CH_4/MMscf processed [e]	*Not specified*	*1.425×10^{-4} tonnes $CH_4/10^6$ scf processed*		*8.56 scf gas/10^6 scf processed*
			5.034×10^{-3} tonnes $CH_4/10^6$ Sm^3 processed		*8.56 Sm^3 gas/10^6 Sm^3 processed*

Footnotes and Sources:

[a] Shires, T.M. and M.R. Harrison. *Methane Emissions from the Natural Gas Industry, Volume 12: Pneumatic Controllers*, *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_4 concentration associated with these emission factors is provided in Table E-4.

[b] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[c] CH_4 emission factors converted from scf or m^3 are based on 60°F and 14.7 psia.

[d] Converted assuming 8,760 hours/yr operation.

[e] Shires, T.M. and C.J. Loughran. *Updated Canadian National Greenhouse Gas Inventory for 1995, Emission Factor Documentation*, *Technical Memorandum*, August 23, 2001.

Most pumps used in gas processing plants are electric motor-driven pumps. However, some natural gas driven pneumatic pumps may be present. Emissions from gas driven pneumatic pumps located in processing plants can be estimated using the same estimation methodologies and emission factors as those described in Section 6.3.7 for production. While there are no segment-specific emission factors for natural gas driven pneumatic pumps in processing, emission factors from Table 6-16 may be applied.

6.5.2 Gas Treatment Processes

The gas treatment processes common in gas plants that may lead to CH_4 and CO_2 venting include gas dehydration and acid gas removal. While glycol dehydration is used in gas processing, the other common type of gas dehydration process in gas plants is molecular sieve dehydration, which can achieve higher levels of water removal. However, molecular sieve dehydration processes, including the molecular sieve regeneration cycle, are closed loop and do not lead to direct venting of CH_4. Likewise, other gas treatment operations in gas plants, such as fractionation processes, do not have associated CH_4 or CO_2 venting.

6.5.2.1 Glycol Dehydration

Emissions from glycol dehydrators located in the gas processing segment can be estimated using the same estimation methodologies described in Section 6.3.8.1 for production. Segment specific default emission factors for glycol dehydrators in the gas processing segment are provided below in Table 6-35. The default emission factors based on volume of gas throughput are based on the original GRI/EPA study, using both site data and computer simulations (Myers, 1996). These factors do not include emissions from a natural gas-assisted pump used for glycol circulation (sometimes referred to as Kimray pumps), which can be found in Table 6-36. Table 6-36 also includes default emission factors taken from EPA's GHGI (EPA, 2019b), which are based on industry reported data under EPA's GHGRP using primarily simulation models for quantifying CH_4 emissions.

Table 6-35. Processing Segment Specific Uncontrolled Gas Dehydration CH_4 Emission Factors

Source	Methane Emission Factor, Original Units	Uncertainty [a] (± %)	Methane Emission Factor [b], Converted to Tonnes Basis	Methane Content Basis (mole %)	Whole Gas Emission Factor, Converted
Glycol Dehydrators	121.55 scf $CH_4/10^6$ scf gas processed [c, d]	249	0.0023315 tonnes $CH_4/10^6$ scf gas processed	86.8	140.03 scf gas/10^6 scf gas processed
			0.082338 tonnes $CH_4/10^6$ Sm^3 gas processed		140.03 Sm^3 gas/10^6 Sm^3 gas processed
	18,276.96 kg CH_4/plant-yr [e]	Not specified	18.28 tonnes CH_4/plant-yr		1.098×10^6 scf gas/plant-yr

Footnotes and Sources:

[a] Uncertainty is based on a 95% confidence interval; however, because the data used to calculate the reference emission factor were unavailable, the uncertainty at a 95% confidence interval was calculated based on the uncertainty at a 90% confidence interval presented in the source, assuming a data set size of 10.

[b] CH_4 emission factors converted from scfy are based on 60°F and 14.7 psia.

[c] Myers, D.B. *Methane Emissions from the Natural Gas Industry, Volume 14: Glycol Dehydrators, Final Report*, GRI-94/0257.31 and EPA-600/R-96-080n, Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[d] Excludes emissions from natural gas-assisted glycol circulation pump.
[e] U.S. Environmental Protection Agency (EPA), Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017 (GHGI), 2019.

The emission factors in Table 6-35 can be scaled based on the ratio of the site-specific CH_4 content to the default emission factor concentration if the site natural gas has a significantly different CH_4 content from the default basis of 86.8 mole %. However, if process-specific data is available, it is preferable to use a process simulator to quantify emissions at a significantly different CH_4 content, since emissions are dependent on the solubility characteristics of CH_4 in glycol at the process conditions in the contactor, which may not be directly proportional to the ratio of CH_4 concentrations in the treated wet gas stream. Note that CO_2 is not appreciably soluble in glycol; therefore, CO_2 emissions are expected to be negligible, even if the gas contains significant quantities of CO_2.

Note that the emission factors given in Table 6-35 do not include the emissions from gas-assisted glycol pumps, which can be a significant source of CH4 emissions. Default emission factors were developed using GRI-GLYCalcTM (Texaco, 1999) that include gas-assisted glycol pump emissions. These emission factors presented in Table 6-35 are not segment-specific, and can be applied to the processing segment for estimation of CH_4 emissions from glycol dehydrators.

Alternatively, default emission factors can be used to quantify the CH_4 emissions from the glycol circulation pump separately and added to the emissions derived using Table 6-36. The default emission factors for the glycol circulation pump applicable to the gas processing segment is derived from the GRI/EPA study (Volume 15) based on technical data from Kimray and using assumptions about typical dehydrator operation (Myers and Harrison, 1996). Kimray pump CH_4 emissions for the gas processing segment are given in Table 6-36. This table also includes the default CH_4 content that can be used for adjusting the emission factors to other CH_4 contents. The default CH_4 content and associated uncertainties for each industry segment are provided in Table D-4.

Table 6-36. GRI/EPA Kimray Pump CH_4 Emission Factors

Source	**Methane Emission Factor [a], Original Units**	**Uncertainty [b] (± %)**	**Methane Emission Factor [c], Converted to Tonnes Basis**	**Methane Content Basis (mole %)**	**Whole Gas Emission Factor, Converted**
Kimray Pump	177.75 scf $CH_4/10^6$ scf gas processed	61.5	0.0034096 tonnes $CH_4/10^6$ scf gas processed	86.8	205 scf gas/10^6 scf gas processed
			0.12041 tonnes $CH_4/10^6$ Sm^3 gas processed		205 Sm^3 gas/10^6 Sm^3 gas processed

Footnotes and Sources:

[a] Myers, D.B. and M.R. Harrison. *Methane Emissions from the Natural Gas Industry, Volume 15: Gas Assisted Glycol Pumps*, Final Report, GRI-94/0257.33 and EPA-600/R-96-080o, Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[b] Uncertainty is based on a 95% confidence interval; however, because the data used to calculate the reference emission factor were unavailable, the uncertainty at a 95% confidence interval was calculated based on the uncertainty at a 90% confidence interval presented in the source assuming a data set size of 10.

[c] CH_4 emission factors converted from scfy are based on 60°F and 14.7 psia.

As in the production segment, some glycol dehydrators also introduce stripping gas in the regenerator to help strip water and other absorbed compounds out of the glycol by increasing the vapor flow rate in the reboiler still. Any CH_4 in the stripping gas will pass directly through the regenerator; therefore, the use of dry natural gas will increase CH_4 emissions from the regenerator. GLYCalc should be used to estimate CH_4 emissions in this situation, as the default approaches presented in this subsection do not account for the use of stripping gas. The emission factors presented in Tables 6-35 or 6-36 may be used to estimate emissions from the dehydrator if flash gas or nitrogen is used as the stripping gas, as CH_4 emissions will not be increased.

An example calculation for dehydrator CH_4 emissions in the gas processing segment is given in Exhibit 6-28 below.

EXHIBIT 6-28: Sample Calculation for Glycol Dehydrator Vent Emissions in Processing Segment

INPUT DATA:
A glycol dehydrator at a gas processing plant treats 25 × 10^6 scf/day of gas with a CH_4 molar content of 90% and CO_2 content of 5%. The dehydration unit includes a natural gas operated Kimray pump but does not include a flash separator. The glycol circulation rate is 200 gallons/hr, and the contactor pressure is 600 psig. Stripping gas is not used in the process. Calculate the CH_4 and CO_2 emissions.

CALCULATION METHODOLOGY:
1. *Calculate the CH_4 emissions.* Emissions are calculated from the glycol dehydration unit without the Kimray pump using an emission factor specific to gas processing facilities, taken from Table 6-35. Because the CH_4 content of this facility differs from the 86.8% default CH_4 content associated with the emission factor presented in Table E-4, the calculations include an adjustment for the composition:

$$E_{CH_4} = \frac{25\times10^6\ \text{scf}}{\text{day}} \times \frac{365\ \text{day}}{\text{yr}} \times \frac{0.0023315\ \text{tonne CH}_4}{10^6\ \text{scf}} \times \frac{\text{tonne mole CH}_4}{16\ \text{tonne CH}_4}$$
$$\times \frac{0.90\ \text{tonne mole CH}_4\ \text{(facility)}}{0.868\ \text{tonne mole CH}_4\text{(default)}} \times \frac{16\ \text{tonne CH}_4}{\text{tonne mole CH}_4}$$

$$\underline{E_{CH_4} = 22.06\ \text{tonnes CH}_4/\text{yr}}$$

For the gas assisted glycol circulation pump, Table 6-36 provides a CH_4 emission factor of 0.0034096 tonnes $CH_4/10^6$ scf of gas processed. The CH_4 emissions from the Kimray pump is calculated using this approach as shown below.

$$E_{CH_4,pump} = \frac{25\times10^6\ \text{scf}}{\text{day}} \times \frac{365\ \text{day}}{\text{yr}} \times \frac{0.0034096\ \text{tonne CH}_4}{10^6\ \text{scf}} \times \frac{0.90\ \text{tonne mole CH}_4\ \text{(facility)}}{0.868\ \text{tonne mole CH}_4\ \text{(default)}}$$

$$\underline{E_{CH_4,pump} = 32.26\ \text{tonnes CH}_4/\text{yr}}$$

The total CH_4 emissions from the glycol dehydration unit are estimated as:

$$\underline{E_{Total} = E_{CH_4} + E_{CH_4,\ pump} = 54.3\ \text{tonnes CH}_4/\text{yr}}$$

CO_2 emissions for the glycol pump are calculated by correcting the CH_4 emissions by the ratio of CH_4 to CO_2 in the facility gas. The CO_2 emissions from the glycol dehydration unit itself are assumed negligible due to the low solubility of CO_2 in glycol.

$$E_{CO_{2pump}} = 32.26 \text{ tonnes} \frac{CH_4}{yr} \times \frac{\text{tonne mole } CH_4}{16 \text{ tonne } CH_4} \times \frac{\text{tonne mole gas}}{0.90 \text{ tonne mole } CH_4}$$

$$\times \frac{0.05 \text{ tonne mole } CO_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne } CO_2}{\text{tonne mole } CO_2}$$

$$\underline{E_{CO_2,\ pump} = 4.93 \text{ tonnes } CO_2/yr}$$

6.5.2.2 Acid Gas Removal/Sulfur Recovery Units

Emissions of both CH_4 and CO_2 from AGRs/SRUs located in the gas processing segment can be estimated using the same estimation methodologies and emission factors as those described in Section 6.3.8.4 for production. See Equation 6-17 and Equation 6-18, as well as emission factors listed in Table 6-19.

The table below provides the default emission factor for acid gas removal at a gas processing plant taken from EPA's GHGI, which references the 1996 EPA/GRI study (Shires, 1996).

42,762.9 kg CH_4/plant-year (Original Units) [a,b]
42.8 tonnes CH_4/plant-year
2.57 x 10^6 scf whole gas/plant-year [c]

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (EPA), Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017 (GHGI), 2019.

[b] Uncertainty is not specified for this value.

[c] Converted to whole gas assuming 86.8 mole % CH_4 composition in gas.

6.5.3 Storage Tank Emissions

In the gas processing segment, any vented emissions of CH_4 from storage tanks are generally associated with tanks that use natural gas as a blanket gas for safety reasons, or working and standing losses from uncontrolled fixed roof condensate tanks, which are less common in gas processing plants than in production. For condensate tanks in gas processing that may have either gas flashing losses (i.e., unstabilized condensate tanks) or working and standing losses (i.e., stabilized atmospheric condensate tanks), refer to Section 6.3.9 for quantification methods.

6.5.3.1 Natural Gas Blanketed Tank Emissions

Some tanks are blanketed with natural gas to prevent air from collecting in the headspace creating an explosive gas mixture. Blanket gas may be used for tank storage of: crude, condensate, produced water, glycol, amine and other bulk chemicals. While natural gas is used for tank blanketing in some applications, nitrogen or produced CO_2 may also be used. If natural gas is used and the blanket gas supply is taken downstream of the total fuel gas meter, then the vented blanket gas volume must be subtracted from the total fuel gas volume (used to determine combustion emissions).

If the tanks are uncontrolled (i.e., the vapor space vents to atmosphere), CH_4 emissions (and possibly CO_2 emissions, if present in the natural gas or used as blanket gas) occur as the natural gas is displaced by the liquid pumped into the tanks. The recommended approach for estimating emissions from this source is the equation for cold process vents presented in Section 6.3, as shown below in Equation 6-2, converted to an annual basis.

$$E_x = VR \times F_x \times \frac{MW_x}{\text{molar volume conversion}} \times T_v \qquad \text{(Equation 6-8)}$$

where

E_x = Emissions of "x" in units of mass (pounds, kg, tonnes);
"x" = GHG compound of interest (CH_4 or CO_2, for CO_2 rich streams);
VR = Vent rate in volume units at STP conditions per unit of time (e.g., scfh or Sm^3/hr);
F_x = Molar fraction of compound "x" in the vent gas stream;
MW_x = Molecular weight of compound "x";
Molar volume conversion = Conversion from molar volume to mass (379.3 scf/lbmole or 23.685 Sm^3/kgmole at STP conditions); and
T_v = Time duration of the venting (hours).

The blanket natural gas is generally charged to the tank intermittently rather than continuously. Thus, the emissions are based on vapor displacement when liquid fills the tank rather than based on a continuous flow of the natural gas to the tank. The vent rate (VR) term in Equation 6-2 is assumed to be the vapor displacement due to filling the tank with liquid. It is the total increase in liquid height, without taking reductions for decreases in the liquid height. Note that filling and emptying a tank simultaneously at the same flow rate would result in no net change in the liquid height and consequently no displacement of natural gas to the atmosphere. Thus, the volumetric increase in liquid level should be used in the calculation. However, a site may not monitor liquid level changes. In this case, the site may only know liquid throughput rates. This liquid throughput rate can be used for the VR term in the absence of liquid level data, recognizing that this will likely overestimate emissions since it does not take into account the liquid level effects caused by emptying the tank at the same time as filling.

A sample calculation for natural gas blanketed tank emissions is shown below in Exhibit 6-29.

EXHIBIT 6-29: Sample Calculation for Natural Gas Blanketed Tank Emissions

INPUT DATA:

A natural gas blanketed tank has an annual liquid throughput of 36,500 bbl/year. However, the facility records the tank liquid level, and the total increase in liquid height during the year is 32,000 bbl. The total volumetric increase in liquid height is less than the total throughput since emptying of the tank occurs while simultaneously filling during some periods of the year. The blanket natural gas contains approximately 82 mole % CH_4 and 1 mole % CO_2. The estimated annual temperature in the tank vapor space is 75°F. Calculate the CH_4 and CO_2 emissions.

CALCULATION METHODOLOGY:
Equation 6-2 is used to estimate the annual emissions. However, the VR term in the equation is on a standard ft^3 basis (scf), and the annual volumetric rate is on an actual ft^3 basis at 75°F (acf), so the actual vent rate must be converted to standard conditions of 1 atm and 60°F.

The actual volumetric displacement rate of 32,000 bbl/yr is used instead of the annual liquid throughput of 36,500 bbl/yr since it represents the actual natural gas displaced. First, the volumetric displacement is converted from barrels to actual cubic feet.

$$V = \frac{32{,}000 \text{ bbl}}{\text{yr}} \times \frac{42 \text{ gal}}{\text{bbl}} \times \frac{\text{ft}^3}{7.4805 \text{ gal}} = 179{,}667 \text{ ft}^3 \text{ (at 75°F)}$$

Next, Equation 3-5 is applied to convert from acf to scf (note that the actual and standard conditions are both at 1 atm). Also note that the equation requires absolute temperatures (°R).

$$V_{\text{scf}} = (179{,}667 \text{ ft}^3) \times \left[\frac{(1 \text{ atm})\ (60 + 459.7)}{(1 \text{ atm})\ (75 + 459.7)} \right] = 174{,}627 \text{ scf (at 60°F and 1 atm)}$$

Lastly, Equation 6-2 is used to calculate the emissions.

CH_4 Emissions:

$$E_{CH_4} = \frac{174{,}627 \text{ scf}}{\text{yr}} \times \frac{0.82 \text{ scf } CH_4}{\text{scf gas}} \times \frac{16 \text{ lb } CH_4/\text{lbmole } CH_4}{379.3 \text{ scf } CH_4/\text{lbmole } CH_4} \times \frac{\text{tonnes}}{2204.62 \text{ lb}}$$

$$\underline{E_{CH_4} = 2.74 \text{ tonnes } CH_4 / \text{yr}}$$

CO_2 Emissions:

$$E_{CO_2} = \frac{174{,}627 \text{ scf}}{\text{yr}} \times \frac{0.01 \text{ scf } CO_2}{\text{scf gas}} \times \frac{44 \text{ lb } CO_2/\text{lbmole } CO_2}{379.3 \text{ scf } CO_2/\text{lbmole } CO_2} \times \frac{\text{tonnes}}{2204.62 \text{ lb}}$$

$$\underline{E_{CO_2} = 0.09 \text{ tonnes } CO_2 / \text{yr}}$$

6.5.4 Compressor Venting

Similar to the gathering and boosting segment, venting from compressors in the gas processing segment occurs from wet seals in centrifugal compressors or rod packing surrounding the mechanical compression components in reciprocating compressors. Compressors are a source of vented emissions of CH_4 from the compressor seals during normal operation and during standby mode when the compressor is pressurized and gas escapes through the seals. Venting also occurs when pressurized gas in compressor is released when the blowdown valve is opened and the compressor is depressurized. This compressor blowdown venting is discussed in Section 6.5.5 below.

As previously discussed in Section 6.4.3, compressors are also a source of fugitive emissions from leakage across the compressor blowdown valve when the compressor is pressurized or from the isolation valves when the compressor is depressurized and the blowdown valve is open. These fugitive emission sources are covered in Section 7 under fugitive emissions from compressors.

6.5.4.1 Reciprocating Compressor Venting

To quantify the CH_4 vented volume from reciprocating compressor rod packing, the most accurate approach is direct measurement. As discussed in Section 6.4.3.1, the CCAC sets out guidance for direct measurement in the CCAC Technical Guidance Document Number 4: Reciprocating Compressors (CCAC, 2017c). In the absence of measurement data, default CH_4 emission factors can be used to quantify the vented emissions from reciprocating compressor rod packing seals.

Default emission factors are provided in Table 6-37 are based on the 2017 CCAC Technical Guidance Document Number 4: Reciprocating Compressors Rod Seal/Packing Vents (CCAC, 2017c), and EPA's GHGI (EPA, 2019b).

Table 6-37. Emission Factors for Reciprocating Compressors in Natural Gas Processing

Controller Type	Emission Factor, Original Units	Uncertainty (±%)	Emission Factor [a], Converted to Tonnes Basis	Methane Content Basis (mole %)	Whole Gas Emission Factor, Converted
Reciprocating Compressor	16,315 kg CH_4/compressor-yr [b, c]	Not specified	16.3 tonnes CH_4/compressor-yr [d]	86.8 [e]	9.81×10^5 scf gas/ compressor-yr [d]
Rod Packing	142.5 scf CH_4/compressor-hr [f, g]	Not specified	0.0027 tonnes CH_4/compressor-hr	87 [h]	163.8 scf gas/compressor-hr

Footnotes and Sources:

[a] CH_4 emission factors converted from scf are based on 60°F and 14.7 psia.

[b] Data from 2017. Calculated using year-specific GHRP Subpart W data for emission source, taken from U.S. Environmental Protection Agency (EPA), Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017 (GHGI), 2019.

[c] Note that emission factor is based on reported data which includes venting from rod packing and fugitive emissions from the blowdown valve in operating and standby pressurized modes, as well as fugitive emissions from the isolation valve in not operating, depressurized mode. Reported data is derived from measurements required under Subpart W of the US EPA GHGRP.
[d] The emission factor was not converted to an hourly rate since it reflects the annual US data reported under Subpart W for all modes (i.e., operating mode, standy pressurized mode, and not operating depressurized mode) on average during the year, and thereby should be applied as an average for the entire year.
[e] U.S. Environmental Protection Agency (EPA), Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017 (GHGI), 2019.
[f] Climate and Clean Air Coalition (CCAC) O&G Methane Partnership, Technical Guidance Document Number 4: Reciprocating Compressors Rod Seal/Packing Vents, April 2017.
[g] Emission factor represents normal operation. A factor of 150% should be applied to the default operating emission factor standby under-pressure factors.
[h] EPA. Natural Gas STAR Lessons Learned. https://www.epa.gov/sites/production/files/2016-06/documents/ll_rodpack.pdf.

Gas processing facilities can calculate GHG emissions from reciprocating compressor rod packing venting using Equation 6-29, based on the average time that the reciprocating compressor is in pressurized mode.

6.5.4.2 Centrifugal Compressor Venting

Centrifugal compressors have seals on the rotating shafts that mitigate the escape of compressed natural gas. These seals can be wet or dry, which is descriptive of the type of seal: either high-pressure oil (wet) or mechanical (dry).

Venting from Wet Seals

Typically, gas emissions from wet seal compressors are higher than that of dry seal compressors, due to the degassing process required for wet seal compressors. In a wet seal compressor, high pressure oil circulates through the casing and acts as a barrier against the compressed natural gas. As the oil circulates through the shaft, some compressed natural gas is absorbed into the oil which reduces the liquid's viscosity and lubrication properties. The degassing process of the oil in the wet seal can involve routing the seal oil to an atmospheric tank, and allowing the gas to be released uncontrolled, flared, or routed back to a process (EPA, 2014). Newer designs have sour seal oil trap pots in which the gas from the sour oil is first flashed before being sent to the atmospheric tank (Smith, 2011). The flash gas from the sour oil pot can be recovered, e.g., fuel gas. or routed to flare. With a sour oil pot for gas flashing prior to the seal oil entering the atmospheric tank, the vent gas from the atmospheric tank is considerably lower. If the vent from the atmospheric tank is uncontrolled, CH_4 released from the oil in the degassing process is vented to the atmosphere.

Alternatively, dry seals on centrifugal compressors have simpler designs and are found to have lower gas vent rates than that of wet seals. Springs, hydrodynamic grooves, and non-contact rings in the compressor shaft use opposing force to create a thin gap of high pressure gas which keeps the compressed natural gas sealed inside the casing. As mentioned above, typically wet seals result in higher vented emissions in comparison to that of dry seals.

Direct measurement is the most accurate way to determine venting losses from centrifugal compressor wet seal degassing as set out in the CCAC Technical Guidance Document Number 3: Centrifugal Compressors with "Wet" (Oil) Seals (CCAC, 2017b). Manufacturer data may also be used if available. In the absence of measurement or manufacturer data, default CH_4 emission factors can be used to quantify the vented emissions from centrifugal compressor wet seal degassing or from dry seals.

EPA's GHGRP provides an emission factor for CH_4 emitted from the wet seal degassing of a centrifugal compressor at standard conditions in production and gathering and boosting segments. See below for emission factors from the GHGRP (EPA, 2019a) for venting from centrifugal compressors with wet seals.

1.2×10^7 scf CH_4/compressor-year (Original Units) [a,b]
1,738 scf whole gas/compressor-hour (Converted) [c]
230 tonnes CH_4/compressor-year (Converted)
0.026 tonnes CH_4/compressor-hour (Converted)

Footnotes and Sources:

[a] US Environmental Protection Agency (USEPA), 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Data reported as of August 4, 2019. https://ecfr.io/Title-40/sp40.23.98.w.

[b] Uncertainty is not specified for this value.

[c] Note that the original CH_4 emission factor from the EPA/GRI study was based on 78.8 mole % CH_4 in natural gas from the original study, and 8,760 hours/yr operation in pressurized mode. Therefore, 78.8 mole % CH_4 composition should be used to adjust the emission factor to a different CH_4 content.

Production and gathering and boosting facilities can calculate emissions from wet seal degassing vents using Equation 6-29 from Section 6.4.3.1 for Reciprocating Compressors using the default emission factors for centrifugal compressor wet seals provided in the table above. The emissions for wet seal degassing from centrifugal compressors can be estimated in a similar manner to the example provided in Exhibit 6.4-2 above, by substituting the appropriate emission factor and adjusting for the amount of time the centrifugal compressor is pressurized (i.e., in either normal operation or standby, pressured mode).

Venting from Dry Seals

Dry seals operate mechanically under the opposing force created between the ring(s) affixed to the compressor shaft and static pressure from high-pressure gas. Dry seals have a lower venting profile than wet seals, due to the opposing forces limiting the leakage pathway in dry seal systems. Similar to wet seal systems, the preferred approach to quantifying the CH_4 emissions from centrifugal compressor dry seals is based on site measurements. In the absence of measurement data, default CH_4 emission factors in Table 6-38 below can be used to quantify the vented emissions from centrifugal compressor dry seals, along with wet seal degassing, in the processing segment. These emission factors are from the EPA GHG national inventory (GHGI), which publishes updated annual CH_4 emission factors based on the data reported under the EPA GHGRP.

Table 6-38. Emission Factors for Centrifugal Compressors in Natural Gas Processing

Controller Type	Emission Factor, Original Units [a] (kg CH_4/ compressor-yr)	Uncertainty (±%)	Emission Factor, Converted to Tonnes Basis (tonnes CH_4/ Compressor-yr)	Methane Content Basis (mole %)	Whole Gas Emission Factor, Converted [b, c] (scf gas/ Compressor-hr)
Wet Seal	86,426	Not specified	86.43	86.8	593

Dry Seal	28,192	Not specified	28.19		194

Footnotes and Sources:

[a] Data from 2017. Calculated using year-specific GHGRP Subpart W data for emission source, taken from U.S. Environmental Protection Agency (EPA), Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017 (GHGI), 2019.

[b] CH_4 emission factors converted to scf are based on 60°F and 14.7 psia.

[c] Converted assuming 8,760 hours/yr opertion.

6.5.5 Gas Processing Related Non-Routine Emissions

The GRI/EPA study developed emission factors associated with station blowdown practices at gas processing facilities based on similarities between gas processing and transmission station maintenance practices (Shires, 1996). Maintenance blowdowns at gas plants include compressor blowdowns, compressor starts, and other miscellaneous sources. In addition, EPA's GHGI uses an emission factor on a per plant basis derived from data reported under Subpart W of the US EPA GHGRP. Subpart W requires reporting of each blowdown event with equipment / piping physical volume of 50 cubic feet or greater (i.e., ≥ 50 actual cubic feet of gas volume as determined by the physical volume of equipment and piping between isolation valves).

The processing plant blowdown emission factors are presented in Table 6-39 on both a volumetric gas processing throughput rate and on a per plant basis. These emission factor can be adjusted based on the CH_4 content of the site-specific gas if the natural gas has a significantly different CH_4 content from the default basis. Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

Table 6-39. Gas Processing Segment CH_4 Emission Factor for Non-Routine Activities

Source	Methane Emission Factor, Original Units	Uncertainty (± %)	Methane Emission Factor [b], Converted to Tonnes Basis	Methane Content Basis of Factor (mole %)	Whole Gas Emission Factor, Converted
Gas processing non-routine emissions [a]	184 scf $CH_4/10^6$ scf processed	Not specified	$3.524x10^{-3}$ tonnes $CH_4/10^6$ scf processed	86.8	212 scf gas/10^6 scf processed
			0.1244 tonnes $CH_4/10^6$ Sm^3 processed		212 Sm^3 gas/10^6 Sm^3 processed
Gas processing blowdown venting [c]	54,371.5 kg CH_4/plant-yr	Not specified	54.4 tonnes CH_4/plant-yr		$3.27x10^6$ scf gas/plant-yr

Footnotes and Sources:

[a] Derived from estimated processing blowdown vented methane emissions (2.9475 Bscf/yr, [Harrison et al., Vol. 2, 1996]) and estimated annual gas processed (16,045.855 Bscf/yr [DOE, 1993]).

[b] CH_4 emission factors converted from scf or m^3 are based on 60°F and 14.7 psia. The average CH_4 concentration associated with these emission factors is provided in Table E-4. The CH_4 emission factors can be adjusted based on the relative concentrations of CH_4 and CO_2 to estimate CO_2 emissions.

[c] Data from 2017. Calculated using year-specific GHRP Subpart W data for emission source, taken from U.S. Environmental Protection Agency (EPA), Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017 (GHGI), 2019.

An example is provided in Exhibit 6-30.

EXHIBIT 6-30: Sample Calculation for Processing Non-Routine Related Emissions

INPUT DATA:
A natural gas processing facility treats 20×10^6 m^3 of gas per day. The facility gas has a typical CH_4 content and no CO_2. Estimate the blowdown emissions for this facility.

CALCULATION METHODOLOGY:
The processing plant throughput is multiplied by the emission factor presented in Table 6-39. The CH_4 emission factor is not corrected by the site CH_4 content because the composition is assumed to be consistent with the default emission factor CH_4 content.

Gas processing plant blowdowns:

$$CH_4: \frac{20 \times 10^6 \text{ m}^3}{\text{day}} \times \frac{365 \text{ days}}{\text{yr}} \times \frac{0.1244 \text{ tonnes } CH_4}{10^6 \text{ m}^3} = \underline{908 \text{ tonnes } CH_4/\text{yr}}$$

6.6 Natural Gas Transmission and Storage

The natural gas transmission and storage (T&S) segment comprises the natural gas system infrastructure between the custody transfer at the gathering or processing system extending to the custody transfer at the distribution system (commonly called a “city gate”) or an industrial user. The transmissions and storage segment includes pressurized gas pipeline infrastructure, compressor stations, metering and regulation stations, and supporting equipment. Venting of CH_4, and CO_2 from gas streams with appreciable concentration of CO_2, may occur from compressor venting, storage tanks, natural gas-operated pneumatic controllers, and non-routine releases.

6.6.1 Compressor Venting

Similar to the gathering and boosting segment, venting from compressors in the gas transmission and storage segment occurs from wet seals in centrifugal compressors or rod packing surrounding the mechanical compression components in reciprocating compressors. Compressors are a source of vented emissions of CH_4 from the compressor seals during normal operation and during standby mode when the compressor is pressurized and gas escapes through the seals.

Venting also occurs from the release of pressurized gas in the compressor when the blowdown valve is opened to depressurize the compressor. This non-routine compressor blowdown venting is discussed in Section 6.6.4 below.

As previously discussed in Section 6.4.3, compressors are also a source of fugitive emissions from leakage across the compressor blowdown valve when the compressor is pressurized (i.e., during normal operation or pressurized standby mode) or from leakage across the isolation valves when the compressor is depressurized and the blowdown valve is open. These fugitive emission sources are covered in Section 7 under fugitive emissions from compressors.

6.6.1.1 Reciprocating Compressor Venting

Venting from reciprocating compressor rod packing is most accurately quantified using a direct measurement approach, as set out in the CCAC Technical Guidance Document Number 4: Reciprocating Compressors (CCAC, 2017c). In the absence of measurement data, default CH_4 emission factors can be used to quantify the vented emissions from reciprocating compressor rod packing seals.

Default emission factors are provided in Table 6-40 below for compressor rod packing venting. One set of emission factors is based on a CH_4 measurement study of 45 compressor stations in the transmission and storage segment in the US (Subramanian, 2015). The other emission factors shown in Table 6-40 are derived from site-specific reported data under EPA GHGRP in the U.S.

Table 6-40. Emission Factors for Compressor Rod Packing Based on 2015 Measurement Study in the Transmission and Storage Segment

Source	Original Units, Emission Factor	Uncertainty (± %)	Methane Emission Factor (Converted) (tonnes CH_4/ compressor-hr)	Methane Content Basis of Factor (mole %)	Whole Gas Emission Factor (Converted) [a] (scf gas/ compressor-hr)
Transmission & Storage Reciprocating Compressor Rod Packing – Operating Mode [b]	4.1 scf CH_4/ compressor-min	Not reported	4.72×10^{-3}	93.4	263
Transmission Reciprocating Compressor Rod Packing – Operating Mode [e, f]	2,458 scf CH_4/ compressor-day	Not reported	1.96×10^{-3}	93.4	110
Storage Reciprocating Compressor Rod Packing – Operating Mode [e, g]	3,011.6 scf CH_4/ compressor-day	Not reported	2.41×10^{-3}	93.4	134
Transmission & Storage Reciprocating Compressor Rod Packing – Standby Pressurized Mode [b]	6.0 scf CH_4/ compressor-min	Not reported	6.91×10^{-3}	93.4	385

Source	Original Units, Emission Factor	Uncertainty (± %)	Methane Emission Factor (Converted) (tonnes CH_4/ compressor-hr)	Methane Content Basis of Factor (mole %)	Whole Gas Emission Factor (Converted) [a] (scf gas/ compressor-hr)
Transmission Reciprocating Compressor Rod Packing – Standby Pressurized Mode [e, f]	1,557 scf CH_4/ compressor-day	Not reported	1.24×10^{-3}	93.4	69.5
Storage Reciprocating Compressor Rod Packing – Standby Pressurized Mode [e, g]	2,924.5 scf CH_4/ compressor-day	Not reported	2.34×10^{-3}	93.4	130
Transmission Reciprocating Compressor Rod Packing – average [c, d]	65,000 kg CH_4/ compressor-yr	Not reported	7.42×10^{-3}	93.4	415
Storage Reciprocating Compressor Rod Packing – average [c, d]	70,000 kg CH_4/ compressor-yr	Not reported	7.99×10^{-3}	93.4	446

Footnotes and Sources:

[a] Converted assuming 93.4 mole % CH_4 in natural gas.

[b] Subramanian, R., et al. Environmental Science & Technology, *Supplemental Information: Methane Emissions from Natural Gas Compressor Stations in Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol*, 2015.

[c] EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 – 2017. 2019. These values were calculated using 2017 year-specific GHGRP Subpart W data by region.

[d] Converted assuming 8,760 hours/year operation.

[e] Pipeline Research Council International, Inc. *PRCI White Paper: Methane Emission Factors for Compressors in Natural Gas Transmission and Underground Storage based on Subpart W Measurement Data*. PR-312-18209-E01. October 2019.

[f] PRCI emission factors reported in Table 3-12 based on Subpart W measurement data reported to U.S. EPA under GHGRP.

[g] PRCI emission factors reported in Table 3-34 based on Subpart W measurement data reported to U.S. EPA under GHGRP.

The annual emissions of CH_4 from reciprocating rod packing vents can be estimated using Equation 6-29 based on the time in each operating mode for the compressor. An example calculation is shown in Exhibit 6-31 that illustrates the use of reciprocating compressor rod packing emission factors.

EXHIBIT 6-31: Sample Calculation for Reciprocating Compressor Rod Packing Emissions in Transmission and Storage Segment

INPUT DATA:

A gas transmission compressor station has 5 reciprocating compressors. On average, the reciprocating compressors are in normal operation for 7,970 hr/yr and in standby, pressurized mode for 630 hours in the reporting year. The average CH_4 content of the gas is 90 mole %, with minimal CO_2. Calculate the CH_4 emissions from the compressor rod packing vents during the year.

CALCULATION METHODOLOGY:

Emissions are calculated by multiplying the number of reciprocating compressors by the default emission factors for rod packing in normal operation and standby pressurized modes, respectively, from Table 6-40. Using Equation 6-29, CH_4 emissions from the compressors can be calculated using the average time in each mode. The whole gas emission factors are used and converted to CH_4 based on the site-specific basis of 90 mole % CH_4. Because the gas contains an insignificant quantity of CO_2, emissions of CO_2 do not need to be quantified. Emissions are calculated as shown below:

$$E_{CH_4,\text{ normal operation}} = (5\text{ reciprocating compressors}) \times \frac{263\text{ scf gas}}{\text{compressor-hr}} \times \frac{7{,}970\text{ hrs}}{\text{yr}}$$

$$\times \frac{0.9\text{ lbmole }CH_4}{\text{lbmole gas}} \times \frac{\text{lbmole gas}}{379.3\text{ scf gas}} \times \frac{16\text{ lb }CH_4}{\text{lbmole }CH_4} \times \frac{\text{tonne}}{2204.62\text{ lb}}$$

$$\underline{E_{CH_4,\text{ normal operation}} = 180.5\text{ tonnes }CH_4/\text{yr}}$$

$$E_{CH_4,\text{standby pressurized}} = (5\text{ reciprocating compressors}) \times \frac{385\text{ scf gas}}{\text{compressor-hr}} \times \frac{\text{lbmole}}{379.3\text{ scf}} \times \frac{0.9\text{ lbmole }CH_4}{\text{lbmole gas}}$$

$$\times \frac{16\text{ lb }CH_4}{\text{lbmole }CH_4} \times \frac{\text{tonne}}{2204.62\text{ lb}} \times \frac{630\text{ hrs}}{\text{yr}}$$

$$\underline{E_{CH_4,\text{standby pressurized}} = 20.9\text{ tonnes }CH_4/\text{yr}}$$

$$\underline{E_{CH_4} = E_{CH_4\text{normal operation}} + E_{CH_4\text{standby operation}} = 180.5 + 20.9 = 201.4\text{ tonnes }CH_4/\text{yr}}$$

6.6.1.2 Centrifugal Compressor Venting

As discussed in Section 6.5.4.2, the volume of gas venting from centrifugal compressor seals depends on the type of seal, with wet seals generally having a higher vent rate than dry seals. Direct measurement is the most accurate way to determine venting losses from centrifugal compressor wet seal degassing as set out in the CCAC Technical Guidance Document Number 3: Centrifugal Compressors with "Wet" (Oil) Seals (CCAC, 2017b). In the absence of measurement data, default CH_4 emission factors can be used to quantify the vented emissions from centrifugal compressor wet seal degassing. Likewise, vented emissions from centrifugal dry seals can be quantified using default emission factors in the absence of direct measurement data.

Default emission factors are provided in Table 6-41 below for centrifugal compressor wet degassing and dry seal venting in the transmission and storage segment. Emission factors are provided from two separate but related studies: a) CH_4 measurement study of 45 compressor stations in the transmission and storage segment in the US (Subramanian, 2015) which published an average emission factor for compressor wet seals in operating mode; and b) study based on statistical modeling using the same measurement data set, as well as data from six large transmission and storage operators, and data reported under EPA's GHGRP (Zimmerle, 2015). The latter study published emission factors for an average compressor wet seal and dry seal, taking into consideration all modes of operation.

Table 6-41. Emission Factors for Centrifugal Compressor Seals in the Transmission and Storage Segment

Source	Original Units, Emission Factor	Uncertainty (± %)	Methane Emission Factor (Converted) (tonnes CH_4/ compressor-hr)	Methane Content Basis of Factor (mole %)	Whole Gas Emission Factor (Converted) (scf gas/ compressor-hr)
Centrifugal Compressor Wet Seal – Operating Mode [a]	26.4 scf CH_4/ compressor-min	Not reported	$3.04\text{x}10^{-2}$	93.4	1,696
Transmission Centrifugal Compressor Wet Seal Degassing Vent – Operating Mode [d, e]	160.2 scf whole gas/compressor-hr	Not reported	$2.87\text{x}10^{-3}$	93.4	160
Compressor Wet Seal – average [b, c]	16.0 scf CH_4/ compressor-min	Not reported	$1.84\text{x}10^{-2}$	93.4	1,028
Compressor Dry Seal – average [b, c]	5.0 scf CH_4/ compressor-min	Not reported	$5.75\text{x}10^{-3}$	93.4	321

Footnotes and Sources:

[a] Subramanian, R., et al. Environmental Science & Technology, *Supplemental Information: Methane Emissions from Natural Gas Compressor Stations in Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol*, 2015.

[b] Zimmerle, D, et al, Environmental Science & Technology, *Methane Emissions from the Natural Gas Transmission and Storage System in the United States,* 2015.

[c] Zimmerle study data includes venting from compressor seal as well as fugitive emissions from blowdown and isolation valve leakage.

[d] Pipeline Research Council International, Inc. *PRCI White Paper: Methane Emission Factors for Compressors in Natural Gas Transmission and Underground Storage based on Subpart W Measurement Data*. PR-312-18209-E01. October 2019.

[e] PRCI emission factors reported in Table 3-20 based on Subpart W measurement data reported to U.S. EPA under GHGRP.

The annual emissions of CH_4 from centrifugal compressor wet seal degassing vents can be estimated using the default emission factor from Table 6-41 in operating mode and the total time in operating mode using Equation 6-29. Alternatively, if the total time in operating mode is unknown, the default average emission factors from Table 6-41 for wet seal and dry seal centrifugal compressors can be used. To avoid double counting, it should be noted that these default average emission factors in Table 6-41 for both wet and dry seal centrifugal compressors include both venting from the compressor seals and equipment leak emissions from the blowdown and isolation valve leakage. An example calculation is shown in Exhibit 6-32 that illustrates the use of centrifugal compressor emission factors.

EXHIBIT 6-32: Sample Calculation for Reciprocating Compressor Rod Packing Emissions in Transmission and Storage Segment

INPUT DATA:

A gas storage compressor station has 3 centrifugal compressors with wet seal systems, as well as 2 centrifugal compressors with dry seals from a recent station expansion. No data is available for the amount of time each compressor operates each year. The average CH_4 content of the gas is 95 mole %, with minimal CO_2. Calculate the CH_4 emissions from the centrifugal compressor seal venting during the year.

CALCULATION METHODOLOGY:

Emissions are calculated by multiplying the number of centrifugal compressors with wet and dry seals, respectively, by the appropriate default average emission factors from Table 6-41. The whole gas emission factors are used and converted to CH_4 based on the site-specific basis of 95 mole % CH_4. Because the gas contains an insignificant quantity of CO_2, emissions of CO_2 do not need to be quantified. Emissions are calculated as shown below: Note that the emissions represent both venting from the compressor seals and fugitive emissions from leakage across the closed blowdown and isolation valves for the centrifugal compressors.

$$E_{CH_4,\ \text{wet seals}} = (3\ \text{wet seal compressors}) \times \frac{1{,}028\ \text{scf gas}}{\text{compressor-hr}} \times \frac{8{,}760\ \text{hrs}}{\text{yr}}$$

$$\times \frac{0.95\ \text{lbmole CH}_4}{\text{lbmole gas}} \times \frac{\text{lbmole gas}}{379.3\ \text{scf gas}} \times \frac{16\ \text{lb CH}_4}{\text{lbmole CH}_4} \times \frac{\text{tonne}}{2204.62\ \text{lb}}$$

$$\underline{E_{CH_4,\ \text{wet seals}} = 491.1\ \text{tonnes CH}_4/\text{yr}}$$

$$E_{CH_4,\ \text{dry seals}} = (2\ \text{dry seal compressors}) \times \frac{321\ \text{scf gas}}{\text{compressor-hr}} \times \frac{8{,}760\ \text{hrs}}{\text{yr}}$$

$$\times \frac{0.95\ \text{lbmole CH}_4}{\text{lbmole gas}} \times \frac{\text{lbmole gas}}{379.3\ \text{scf gas}} \times \frac{16\ \text{lb CH}_4}{\text{lbmole CH}_4} \times \frac{\text{tonne}}{2204.62\ \text{lb}}$$

$$\underline{E_{CH_4,\ \text{dry seals}} = 102.2\ \text{tonnes CH}_4/\text{yr}}$$

$$E_{CH_4}=E_{CH_4,\ \text{wet seal}}+E_{CH_4,\ \text{dry seal}} = 491.1+102.2 = 593.3 \text{ tonnes } CH_4/\text{yr}$$

6.6.2 Transmission Storage Tanks

Emissions from storage tanks in the transmission and storage segment can be estimated using the same methodologies as those described in Section 6.3.9. In the transmission segment, storage tanks may be used to collect residual liquids that accumulate in the transmission lines and could result in some flashing from pipeline pigging operations as previously described, as well as working and standing losses. The volume of liquids accumulated from transmission lines is minimal and therefore, venting from flashing, working and standing losses from condensate storage tanks is typically an insignificant source of methane emissions. Vented methane emissions from condensate storage tanks in this segment are primarily attributed to leakage from the dump valve feeding the storage tank, which is measured as part of EPA's GHGRP Subpart W reporting. Transmission and storage segment tank flashing, working and standing losses, and separator dump valve losses can be estimated using the same approaches presented in Section 6.3.9 for the production segment.

In the absence of site-specific data to quantify CH_4 emissions from storage tanks in transmission and storage, default emission factors may be used. The table below presents CH_4 emission factors based on a measurement program conducted at transmission compressor and storage facilities in the US (Subramanian, 2015).

2.6 scf CH_4/tank-minute (Original Units) [a, b]
26.2 tonnes CH_4/tank-year (Converted) [c]

Footnotes and Sources:
[a] Subramanian, R., et al. Environmental Science & Technology, *Supplemental Information: Methane Emissions from Natural Gas Compressor Stations in Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol*, 2015.
[b] Uncertainty is not specified for this value.
[c] Converted assuming 8,760 hrs/yr operation.

6.6.3 Gas-Driven Pneumatic Controllers

In the transmission segment, compressor and storage stations commonly employ gas-operated isolation valves, as well as other types of natural gas-operated pneumatic controllers. At meter and pressure regulating stations, natural gas-driven pneumatic controllers may also be used. Emissions of CH_4 (and CO_2, if present in the gas) from pneumatic controllers located in transmission and storage systems can be estimated using the same estimation methodologies as those described in Section 6.3.6 for production. If site-specific controller measurements or manufacturer's data is available, the calculation methods presented in Section 6.3.6 can be applied for continuous and intermittent vent controllers, respectively. See Equation 6-11 for estimating the volume of gas vented using controller-specific data from continuous vent pneumatic controllers, and Equations 6-12 or 6-13 for intermittent vent pneumatic controllers.

Alternatively, default emission factors presented by controller type are provided in Table 6-42 below for continuous vent and intermittent vent pneumatic controllers, as well as an overall average, in the transmission and storage segment. The segment average emission factor in Table 6-42 is based on a measurement program conducted at transmission compressor and storage facilities in the US (Subramanian, 2015). The continuous and intermittent vent controller emission factors are taken from a modeling study using measurement data, data from six large transmission and storage operators, and data reported under the US EPA GHGRP (Zimmerle, 2015). Facility level emission factors for natural gas pneumatic controllers at transmission and storage stations are based on a 2019 study by the Pipeline Research Council International, Inc. based on data reported for 2015-2016 under the EPA GHGRP (PRCI, 2019a).

Table 6-42. Natural Gas-Driven Pneumatic Controller Methane Emission Factors in Transmission and Storage

Controller Type	Original Units, Emission Factor	Uncertainty (± %)	Methane Emission Factor (Converted) [a] (tonnes CH_4/ controller-yr)	Methane Content Basis of Factor (mole %)	Whole Gas Emission Factor (Converted) (scf gas/controller-hr)
Continuous Vent Controller [b]	3.5 Mg CH_4/ controller-yr	Not reported	3.5	93.4	22.3
Intermittent Vent Controller [b]	0.4 Mg CH_4/ controller-yr	Not reported	0.4	93.4	2.5
Transmission or Storage average (if controller type is unknown) [c]	0.3 scf CH_4/ controller-min	Not reported	3.0	93.4	19.3
Transmission or Storage facility average [d]	541 tonnes CO2e/ station-yr	Not reported	21.6 tonnes CH_4/station-yr	93.4	1.21 MMscf gas/station-yr

Footnotes and Sources:

[a] Converted assuming 8,760 hours/yr operation.

[b] Zimmerle, D, et al, Environmental Science & Technology, *Methane Emissions from the Natural Gas Transmission and Storage System in the United States,* 2015.

[c] Subramanian, R., et al. Environmental Science & Technology, Supplemental Information*: Methane Emissions from Natural Gas Compressor Stations in Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol,* 2015.

[d] Pipeline Research Council International, Inc. *Methane Emissions from Transmission and Storage Subpart W Sources. CPS-17-01.* PR-312-16202-R03. August 2019. Table 3.

6.6.4 Other Transmission and Storage-Related Venting Emissions

Consistent with the gas processing segment, the transmission segment emission factors include both “maintenance and turnaround” and “other releases” from non-routine activities. A summary of the CH_4 emission factors from the transmission segment non-routine activities is presented in Table 6-43. Note that the factors shown in Table 6-43 are provided on an equipment/facility basis, not a per-event basis.

The gas compressor station and storage station blowdown emission factors represent an overall station factor that includes compressor blowdowns, compressor starts, PRV releases, ESD activation, and other non-routine venting (Zimmerle, 2015). The gas transmission pipeline venting emission factor is based on transmission pipeline blowdowns reported under US EPA GHGRP (Subramanian, 2015). The vented emission factor for meter and pressure regulating (M&R) stations is based on company data from a Canadian study (URS Corporation, 2001).

The miscellaneous factor includes M&R, odorizer, drips[11], sampling, pigging, and dehydrators. These miscellaneous activities can be quite variable so using a material balance equation approach would provide a more accurate emission estimate. For example, emissions of CH_4 (and CO_2 if present in the gas) released from drips could be estimated based on the volume of gas entrained in the liquid and the liquid quantity captured. Any other gas venting from this operation would also be estimated using a material balance approach based on how the separation takes place, if such gas venting occurs.

The non-routine emission factors given in Table 6-43 can be adjusted based on the CH_4 content of the site-specific gas if the natural gas has a significantly different CH_4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

Table 6-43. Transmission and Storage Segment Methane Emission Factors for Non-Routine Activities

Source	Original Units, Emission Factor	Uncertainty [a] (± %)	Methane Emission Factor (Converted)	Methane Content Basis of Factor (mole %)	Whole Gas Emission Factor (Converted) (scf gas/ station-yr)
Transmission Station Blowdowns [b]	54 Mg CH_4/ station-yr	Not reported	54 tonnes CH_4/station-yr	93.4	3,014 $\times 10^3$
Storage Station Blowdowns [b]	43 Mg CH_4/ station-yr	Not reported	43 tonnes CH_4/station-yr	93.4	2,400 $\times 10^3$
Pipeline venting [c]	613.5 kg CH_4/ mile-yr	Not reported	0.6135 tonnes CH_4/mile-yr	93.4	34.2 $\times 10^3$ scf gas/mile-yr
Compressor blowdowns [d]	2,457 $\times 10^3$ scf CH_4/station-yr	168	47.14 tonnes CH_4/station-yr	93.4	2,631 $\times 10^3$
Engine starts [d]	1,515 $\times$ 10^3 scf CH_4/ station-yr	130	29.06 tonnes CH_4/station-yr	93.4	1,622 $\times 10^3$
PRV lifts [d]	192 $\times$ 10^3 scf CH_4/ station-yr	100 [e]	3.68 tonnes CH_4/station-yr	93.4	206 $\times 10^3$
ESD activation [d]	415 $\times$ 10^3 scf CH_4/station-yr	346	7.97 tonnes CH_4/station-yr	93.4	444 $\times 10^3$
M&R station blowdowns [f]	0.020 $\times$ 10^6 Sm^3 CH_4/station-yr	Not available	13.75	93.4	756 $\times 10^3$

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[11] Pipeline drips involve removing liquids in gas pipelines using in-line separators.

Source	Original Units, Emission Factor	Uncertainty [a] (± %)	Methane Emission Factor (Converted)	Methane Content Basis of Factor (mole %)	Whole Gas Emission Factor (Converted) (scf gas/ station-yr)
Miscellaneous (includes M&R, odorizer, drips, sampling, pigging, dehydrators) [d]	1,134 × 10^3 scf CH_4/station-yr	43.3	21.75	93.4	1,214 ×10^3

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Zimmerle, D, et al, Environmental Science & Technology, *Methane Emissions from the Natural Gas Transmission and Storage System in the United States,* 2015.

[c] Subramanian, R., et al. Environmental Science & Technology, *Supplemental Information: Methane Emissions from Natural Gas Compressor Stations in Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol,* 2015.

[d] Developed from data used for the June 1996 GRI/EPA CH_4 emissions study. Emission factors are based on averaging data by site. The average CH_4 concentration associated with these emission factors is provided in Table E-4.

[e] Based on engineering judgement.

[f] URS Corporation. *Updated Canadian National Greenhouse Gas Inventory for 1995, Emission Factor Documentation. Technical Memorandum, Final*, October 2001.

An example calculation shown in Exhibit 6-33 illustrates the use of the transmission segment non-routine emissions.

EXHIBIT 6-33: Sample Calculation for Transmission Non-Routine Related Emissions

INPUT DATA:

A gas transmission system has 50 miles of gas transmission lines and two compressor stations. The natural gas in the transmission system has a typical CH_4 content and no CO_2. Calculate the non-routine emissions, by activity.

CALCULATION METHODOLOGY:

The transmission station count and transmission pipeline miles are each multiplied by the appropriate emission factor from Table 6-43. The CH_4 emission factors are not corrected by the site CH_4 content because the composition is assumed to be consistent with the default emission factor CH_4 content. As noted above, the gas for this exhibit does not contain CO_2.

Transmission station blowdowns:

$$E_{CH_4}=2 \text{ stations} \times \frac{54 \text{ tonne } CH_4}{\text{station-yr}}$$

$$\underline{E_{CH_4}=108 \text{ tonnes } CH_4/\text{yr}}$$

Transmission gas pipeline blowdowns:

$$E_{CH_4}=50 \text{ miles} \times \frac{0.6135 \text{ tonne } CH_4}{\text{mile-yr}}$$

$$\underline{E_{CH_4}=31 \text{ tonnes } CH_4/\text{yr}}$$

6.7 LNG Operations

The liquefied natural gas (LNG) segment includes the following operations, as described in detail in '*Liquefied Natural Gas (LNG) Operations; Consistent Methodology for Estimating Greenhouse Gas Emissions*' (API, 2015):

- Gas treatment and liquefaction processes;
- Storage and loading operations;
- LNG shipping; and
- LNG import and export terminals.

In this section, the key emission sources related to process venting in LNG operations are discussed, and LNG-specific emission factors are provided, where applicable.

6.7.1 Gas Treatment and Liquefaction Processes

Natural gas feedstock to a liquefaction plant may either be raw material from dedicated gas production fields or gas that has already been through some initial processing. Prior to liquefaction, the feed gas is further treated to remove water, sulfur compounds (primarily hydrogen sulfide), and any residual CO_2 that might be present. It is also treated to remove other components that could freeze (e.g., benzene) under the low temperatures needed for liquefaction, or that could be harmful (e.g. mercury) to the liquefaction facility.

Depending on the feed gas characteristics, LNG operations may include gas treatment prior to the liquefaction process. Many of the same potential venting sources as described in Section 6.5.2, Gas Treatment Processes in Natural Gas Processing, may be applicable to the gas treatment processes in an LNG liquefaction plant. For example, LNG processing includes glycol dehydration and may include acid gas removal, which may result in venting of CH_4 or CO_2. The venting estimation methods as described in Section 6.5.2 for natural gas processing would also apply to gas treatment in an LNG liquefaction plant.

In the liquefaction process, the gas is chilled using multiple compressors, condensers, pressure expansion valves, isentropic expanders and evaporators. The natural gas goes through stages of pre-cooling, liquefaction and sub-cooling until it reaches the desired temperature, and is then stored as LNG in near-atmospheric pressure tanks prior to ship loading. For LNG operations, the primary design characteristic is that all gas, including vaporized gas known as boil-off gas (BOG), is recovered and returned to storage tanks, consumed as fuel, or fed into a boil-off gas recondenser. Consequently, routine continuous venting from LNG operations is minimized.

6.7.1.1 LNG Compressor Venting

Natural gas liquefaction plants utilize reciprocating and/or centrifugal compressors for streams containing LNG or BOG. Emissions from reciprocating compressors are typically associated with rod packing and unflared blowdown venting in its operating mode; blowdown venting in its pressurized standby mode; and leakage through its isolation valve in its shut-down depressurized mode.

Centrifugal compressors may either include oil seals that require periodic degassing or dry seals that pump gas between the seal rings creating a high pressure barrier to leakage. Emissions are associated with blowdown venting in its operating mode, wet-seal degassing in its operating mode and leakage through the isolation valves in its shut-down depressurized mode.

In LNG facilities most, if not all, of the venting is either captured and rerouted to storage vessels or else is sent to a flare to minimize release of cryogenic liquid vapor to the atmosphere. If atmospheric venting from compressors does occur, the emissions can be estimated using the same estimation methodologies described in Section 6.5.4 for Compressor Venting in Natural Gas Processing.

6.7.1.2 LNG Other Generic Process Vents

In LNG operations, atmospheric CH_4 emissions may be caused by other sources through which gas may be vented or released without combustion. Normally, all vents except for small vented gas streams would be routed to a flare, and included in flared emissions (see Section 5 for calculation methodology). These emission sources may include small, miscellaneous vents that occur on an intermittent basis, or may encompass an overall process vent.

Due to the wide variability of sources that could be considered, there are no emission factors or default values for estimating CH_4 and/or CO_2 emissions from these small generic vents in LNG operations. A general material balance approach is required to account for these generic vents, based on source-specific measurements or estimates of the vent rate and concentrations.

For estimating total CH_4 emissions (and CO_2 if composition is significant) from these vents, the following data are needed during the time period of interest (API, 2015):

- If the venting is continuous or periodic;
- Rate of continuous venting or duration and number of periodic venting events;
- Unique physical volumes that are characteristic for each event (or categories of events); and
- Average CH_4 and CO_2 content of each physical volume vented (or categories of such events).

A more detailed description of emission estimation methods from venting when the volume and composition of gas released is known is provided in Section 6.2.2.

6.7.1.3 Non-Routine Vented Emissions from LNG Liquefaction

Non-routine emissions associated with LNG liquefaction operations are primarily associated with start-up or shut-down emissions along with flaring during plant upset. Blowdown losses from facility pipelines, compressors, scrubbers/strainers, pig launchers and receivers, and emergency equipment are examples of non-routine emission sources. Typically, the gas released from equipment blowdown events in LNG operations would be routed to a flare instead of vented to atmosphere. If venting occurs, site-specific data that reflects the LNG facility design and operating practices should be used for calculating vented emissions from plant start-up, shut-down, or upset conditions, if available.

6.7.2 LNG Storage and Loading Operations

LNG storage and loading/unloading operations are typically co-located with an LNG liquefaction plant, but may also be ‘peak shaving’ facilities operated by natural gas utilities and/or pipeline companies that store pipeline natural gas for periods of high demand. The GHG emissions and methodology discussed in this section consider storage emissions but do not address emissions during highly unlikely storage failures. LNG vaporization, or BOG, within vessels and pipelines is due to heat gain from the surroundings, and from energy input from the pumping process. The heat gain that contributes to LNG vaporization is a function of the type and amount of insulation used.

6.7.2.1 LNG Storage

Stored LNG is kept in its liquid state at a near constant cryogenic temperature controlled by allowing the BOG to escape from the tank, in a process known as auto-refrigeration. For LNG storage tanks, BOG may be either captured, flared or (less commonly) vented. Even if captured, BOG may be vented or flared if the vapor generation rate exceeds the capacity of the BOG compressors or the re-liquefaction unit (API, 2015). If BOG is vented (not captured or flared) from a storage vessel, a typical loss may be estimated as 0.050% of the total tank volume per day (Féger, 2010).

BOG from LNG Storage Tank: 0.050 % of total tank volume per day (Original Units) [a, b]

Footnotes and Sources:

[a] D. Féger. “An innovative way of reducing BOG on existing or ‘new built’ LNG storage tanks”, Proceedings LNG16 Congress, Algeria, April 2010.

[b] Uncertainty is not specified for this value.

6.7.2.2 LNG Loading and Unloading

CH_4 and potentially small amounts of CO_2 are also vented or lost to the atmosphere if the BOG is not captured or flared during pipe transfer of LNG, either during loading for transport, off-loading for storage or vaporization, or from gathering lines at terminals and peak-shaving plants (API, 2015). Loading and unloading losses may also occur when the ship, barge or truck loading connection is disconnected.

Table 6-44 below lists typical pipeline loss rates of BOG during loading and unloading of LNG, if the BOG is not captured or flared (note that is the exception, and not the normal design approach). The emission factors listed below in Table 6-44 should only be used to estimate potential emissions if the emissions are not captured or flared. The data in Table 6-44 could also be useful to assess potential GHG emission reductions due to implemented operational changes.

Table 6-44. Typical Pipeline Loss Rates

Pipe Insulation Type	**Typical Loss Rate [a, b, c] (per km of transfer pipe)**
Foam	0.0012%
Powder	0.0006%
Vacuum	0.00012%

Footnotes and Sources:

[a] B. Kitzel, "Choosing the right insulation", LNG Industry, Spring 2008.

[b] Based on LNG transfer rate of 228 m^3/min and heat transfer coefficient of pipe wall insulation, where U (W/m^2K) = 0.26 (foam), 0.13 (powder), and 0.026 (vacuum).

[c] Uncertainty is not specified for these values.

6.7.2.3 Non-Routine Vented Emissions from LNG Storage Stations

For LNG storage peak-shaving facilities, in addition to BOG losses from the storage tanks, they may also have non-routine blowdown losses from BOG compressors, pumps, and pipelines. In the absence of site-specific data, default emission factors could be used as an alternative for accounting for venting from blowdown losses in LNG peak-shaving operations. EPA's GHGI provides emission factors for LNG station blowdowns that are derived based on the 1996 GRI/EPA study (Shires et al, 1996b). As shown in the table below, the blowdown emission factors are converted to whole gas assuming 95 mole percent CH_4 in LNG.

83,954 kg CH_4/facility-yr (Original Units) [a, b]
83.95 tonnes CH_4/facility-yr (Converted)
4.61 MMscf gas/facility-yr (Converted) [c, d]

Footnotes and Sources:

[a] EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 – 2017. 2019. These values are based on the GRI/EPA 1996 study.

[b] Uncertainty is not specified for this value.

[c] Emission factors converted from kg are based on 60°F and 1 atm.

[d] CH_4 content used for conversion to whole gas is 95 mole % CH_4, the default mole fraction of CH_4 in natural gas stored in the LNG storage industry segment in 40 CFR 98 Subpart W.

6.7.3 LNG Shipping

LNG is shipped in double-hulled vessels that are specially designed and insulated to enable safe and reliable transport of LNG from liquefaction facilities to receiving terminals, while minimizing the amount of LNG that boils off. The tankage and BOG management systems are designed to maintain the cargo tank pressure below the maximum allowable relief valves (MARVS) settings or to safely utilize or dispose of the natural LNG boil-off gas at all times, including while in port, maneuvering or standing (API, 2015). LNG tankers typically burn the natural gas boiled off from the stored LNG as fuel, supplemented by fuel oil, to power their propulsion system. Many of the new LNG tankers, including the QFlex (capacity to 216,000 m3) and Q-Max (capacity to 266,000 m3) LNG carriers, both first delivered in 2007, are much larger than the LNG carriers in service prior to that point in time. These newer ships utilize slow speed diesel-powered propulsion systems and have onboard re-liquefaction facilities to re-liquefy boil-off gas and return it to the ship's LNG tanks.

If no BOG from storage during shipping is combusted or re-liquefied, the vented BOG emissions may be estimated at 0.15% of the total ship storage volume per day (Sempra, 2008). If the BOG gas is consumed by propulsion combustion or re-liquefied, some BOG may be still be vented if the BOG exceeds the ship's capacity for recovery.

BOG from Vessels During Shipping: 0.15 % of total ship storage volume per day (Original Units) [a, b]

Footnotes and Sources:
[a] Sempra LNG, *GHG life-cycle emissions study: U.S. Natural Gas Supplies and International LNG*, November 2008.
[b] Uncertainty is not specified for this value.

6.7.4 LNG Import and Export Terminals

Delivered LNG is received from ships or trucks at import (regasification) terminals. The LNG is initially pumped from the ship or truck to the receiving terminal's LNG storage tanks. Most LNG receiving terminals are only capable of pumping and vaporizing LNG. The LNG is either transferred further in its liquid state (loaded onto trucks for transport to smaller storage facilities) or pumped to higher pressure, vaporized, and sent to the export gas pipeline (API, 2015).

EPA's GHGI provides emission factors for LNG import and export terminal blowdowns. The import terminal blowdown emission factor is based on a three year average (i.e., average of reporting years 2015 – 2017) of data reported under EPA's GHGRP under 40 CFR 98 Subpart W, which represents blowdowns in LNG operations resulting from facility piping, pipeline venting, compressors, scrubbers/strainers, pig launchers and receivers, emergency shutdowns, and/or any other equipment with a physical volume greater than or equal to 50 cubic feet (EPA, 2019a).

1,317,381 kg CH_4/import terminal-yr (Original Units) [a, b]
1,317.4 tonnes CH_4/import terminal-yr (Converted)
72.3 MMscf gas/import terminal-yr (Converted) [c, d]

Footnotes and Sources:
[a] EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 – 2017. 2019. This value was based on a three year average of reporting year 2015-2017 data reported under EPA's GHGRP Subpart W.
[b] Uncertainty is not specified for this value.
[c] Emission factors converted from kg are based on 60°F and 1 atm.
[d] CH_4 content used for conversion to whole gas is 95 mole % CH_4, the default mole fraction of CH_4 in natural gas stored in the LNG storage industry segment in 40 CFR 98 Subpart W.

The LNG export terminal blowdown emission factor is derived using the GHGI reported emission factors over the four year period 2015 – 2018, based on data reported under Subpart W of EPA's GHGRP. The export terminal blowdown emission factor was derived as an overall average of the GHGI emission factors reported for the four year period 2015 - 2018.

7,299 kg CH_4/export terminal-yr (Original Units) ± 342% (uncertainty) [a, b]
7.3 tonnes CH_4/export terminal-yr (Converted)
0.401 MMscf gas/export terminal-yr (Converted) [c, d]

Footnotes and Sources:

[a] The emission factor was calculated as the average of 2015 – 2018 emission factors from EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 – 2018. 2020. The GHGI emission factors are based on data reported under the year-specific GHGRP Subpart W data.

[b] Uncertainty is calculated as the 95% confidence interval of the emission factors averaged over 4 years.

[c] Emission factors converted from kg are based on 60°F and 1 atm.

[d] CH_4 content used for conversion to whole gas is 95 mole % CH_4, the default mole fraction of CH_4 in natural gas stored in the LNG storage industry segment in 40 CFR 98 Subpart W.

6.8 Natural Gas Distribution

6.8.1 Natural Gas Driven Pneumatic Controllers

As in the production, gathering and boosting, processing, and transmission and storage segment, natural gas-operated pneumatic controllers are used in natural gas distribution systems. Distribution pneumatic controllers were evaluated as part of a study of Canadian greenhouse gas emissions (Shires, 2001). Some distribution metering and pressure regulating (M&R) stations use gas-operated pneumatic control loops or isolation valves. Emissions of CH_4 (and CO_2, if present in the gas) from pneumatic controllers located in natural gas distribution systems can be estimated using the same estimation methodologies as those described in Section 6.3.6 for production. If site-specific controller measurements or manufacturer's data is available, the calculation methods presented in Section 6.3.6 can be applied for continuous and intermittent vent controllers, respectively. See Equation 6-11 for estimating the volume of gas vented using controller-specific data from continuous vent pneumatic controllers, and Equations 6-12 or 6-13 for intermittent vent pneumatic controllers.

Alternatively, default emission factors presented by controller type are provided in Table 6-45 below for certain pneumatic controllers in the distribution segment. The pneumatic isolation valve emission factor is taken from the 1996 GRI/EPA report (Volume 12) (Shires et al, 1996a). The emission factors for pneumatic control loops and average distribution controllers are taken from a Canadian GHG inventory for 1995 (Shires, 2001). The emission factor for industrial meter regulator venting is based on a GTI study (GTI, 2009). The CH_4 emission factors can be adjusted based on the CH_4 content of the site-specific gas used as motive gas in the pneumatic controllers if the natural gas is different than the emission factor basis shown in the table below. Also, if the pneumatic controllers are driven with gas that contains significant quantities of CO_2, the CH_4 emission factors can be adjusted based on the relative concentrations of the CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

Table 6-45. Emission Factors for Gas-Driven Pneumatic Controllers Located in the Gas Distribution Segment

Controller Type	**Emission Factor [a], Original Units (tonnes CH_4/controller-yr)**	**Uncertainty (±%)**	**Methane Content of Factor (mole %)**	**Whole Gas Emission Factor [b], (Converted) (scf gas/hr-controller)**
Pneumatic isolation valves	0.366	Not specified	93.4	2.33
Pneumatic control loops [c]	3.465		94.4	21.84
Distribution average (if controller type is unknown)	*2.941*		*94.9*	*18.44*
Industrial meter regulator venting [d]	3.847	Not specified	93.4	24.51

Footnotes and Sources:

[a] Shires, T.M. and M.R. Harrison. *Methane Emissions from the Natural Gas Industry, Volume 12: Pneumatic Controllers*, *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_4 concentration associated with these emission factors is provided in Table E-4.

[b] CH_4 emission factors are converted to whole gas basis in scf are based on 60°F, 14.7 psia, 8,760 hr/yr and methane content basis.

[c] Shires, T.M. and C.J. Loughran. Updated Canadian National Greenhouse Gas Inventory for 1995, Emission Factor Documentation, Technical Memorandum, August 23, 2001.

[d] Gas Technology Institute and Innovative Environmental Solutions, *Field Measurement Program to Improve Uncertainties for Key Greenhouse Gas Emission Factors for Distribution Sources*, November 2009.

6.8.2 Other Natural Gas Distribution Venting Related Emissions

Distribution related non-routine emissions are associated with natural gas systems, since the distribution of petroleum liquids is primarily associated with refined liquids that do not contain CH_4. Distribution segment CH_4 emission factors from non-routine activities are presented in Table 6-46. Note that the factors shown in Table 6-46 are provided on an equipment/facility count basis, not a per-event basis. One of the emission factors for pipeline mishaps (dig-ins) is based on a US Study (Lamb et al., 2015). The M&R station blowdown emission factor and the emission factor for odorizer and gas sampling vents are based on a Canadian study (Shires et al, 2001) while the other emission factors are taken from the GRI/EPA Study Volume 2 (Harrison et al., 1996).

The M&R station blowdown emission factor includes emissions from station blowdowns and purges as well as pneumatic isolation valve venting. The pipeline blowdown emission factor is based on gas distribution pipeline blowdowns due to maintenance activities, such as pipe repairs, abandonment, or installation.

Table 6-46. Gas Distribution Segment Emission Factors for Non-Routine Activities

Source	**Methane Emission Factor, Original Units**	**Methane Emission Factor [a], Converted to Tonnes Basis**	**Methane Content Basis of Factor**	**Uncertainty [b] (±%)**	**Emission Factor, Converted to Whole Gas Basis**
M&R Station maintenance/upsets [c]	4.27 m^3 CH_4/station-yr	0.002895 tonnes CH_4/station-yr	94.8 mole %	Not available	159 scf gas/station-yr
Odorizer and gas sampling vents [c]	33.59 m^3 CH_4/station-yr	0.02275 tonnes CH_4/station-yr	94.8 mole %	Not available	1,251 scf gas/station-yr
Pipeline blowdowns (based on mains and services length) [d, e]	1,679 scf CH_4/mile-yr	0.03220 tonnes CH_4/mile-yr 0.02001 tonnes CH_4/km-yr	93.4 mole %	117	1,798 scf gas/mile-yr
Pipeline mishaps (dig-ins) (based on mains and services length) [f]	1,585 scf CH_4/mile-yr	0.03040 tonnes CH_4/mile-yr 0.01889 tonnes CH_4/km-yr	93.4 mole %	2,600	1,697 scf gas/mile-yr
Pipeline mishaps (dig-ins) [g]	2.43 x 10^3 scf CH_4/mile-yr	0.0466 tonnes CH_4/mile-yr 0.0290 tonnes CH_4/km-yr	93.4 mole%	Not available	2,600 scf gas/mile-yr
Pressure relief valves (based on pipeline mains length) [f]	50 scf CH_4/mile-yr	9.591E-04 tonnes CH_4/mile-yr 5.959E-04 tonnes CH_4/km-yr	93.4 mole %	19,300	54 scf gas/mile-yr

Footnotes and Sources:

[a] CH_4 emission factors converted from scf or m^3 are based on 60°F and 14.7 psia.

[b] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[c] URS Corporation. Updated Canadian National Greenhouse Gas Inventory for 1995, Emission Factor Documentation, Technical Memorandum, Final, October 2001.

[d] See derivation in Appendix B.

[e] Radian International. *1995 Air Emissions Inventory of the Canadian Natural Gas Industry*, Final Report, Canadian Gas Association Standing Committee on Environment, September 1997.

[f] Harrison et. al., Methane Emissions from the Natural Gas Industry Volume 2, June 1996.

[g] Lamb et al,, *Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States*, Environmental Science & Technology, February 2015.

Dig-ins are unintentional mishaps that result in gas being released to the atmosphere from main or service distribution gas pipelines.

Similar to the transmission segment, the non-routine emission factors given in Table 6-46 can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH_4 content from the default basis. Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

An example calculation shown in Exhibit 6-34 illustrates the use of the distribution segment non-routine emissions.

EXHIBIT 6-34: Sample Calculation for Distribution Non-Routine Related Emissions

INPUT DATA:
A gas distribution system has 20 miles of gas distribution main lines and three M&R stations. The natural gas in the distribution system has a typical CH_4 content and a no CO_2. Calculate the non-routine emissions, by activity type.

CALCULATION METHODOLOGY:
The M&R station count and pipeline miles are each multiplied by the appropriate emission factor from Table 6-46. The CH_4 emission factors are not corrected by the site CH_4 content because the composition is assumed to be consistent with the default emission factor CH_4 content. As noted above, the gas for this exhibit does not contain CO_2. Emissions are calculated below, by activity type.

M&R station blowdowns:

$$E_{CH_4} = 3\text{ stations} \times \frac{0.002895\text{ tonne CH}_4}{\text{station-yr}}$$

$$\underline{E_{CH_4} = 0.0087\text{ tonnes CH}_4/\text{yr}}$$

Odorizer and gas sampling vents:

$$E_{CH_4} = 3\text{ stations} \times \frac{0.02275\text{ tonne CH}_4}{\text{station-yr}}$$

$$\underline{E_{CH_4} = 0.068\text{ tonnes CH}_4/\text{yr}}$$

EXHIBIT 6-34: Sample Calculation for Distribution Non-Routine Related Emissions, continued

Distribution gas pipeline blowdowns:

$$E_{CH_4} = 20 \text{ miles} \times \frac{0.03220 \text{ tonne } CH_4}{\text{mile-yr}}$$

$$\underline{E_{CH_4} = 0.64 \text{ tonnes } CH_4/\text{yr}}$$

Distribution gas pipeline mishaps (dig-ins):

$$E_{CH_4} = 20 \text{ miles} \times \frac{0.03040 \text{ tonne } CH_4}{\text{mile-yr}}$$

$$\underline{E_{CH_4} = 0.61 \text{ tonnes } CH_4/\text{yr}}$$

Distribution pressure relief valves:

$$E_{CH_4} = 20 \text{ miles} \times \frac{9.591 \times 10^{-4} \text{ tonne } CH_4}{\text{mile-yr}}$$

$$\underline{E_{CH_4} = 0.02 \text{ tonnes } CH_4/\text{yr}}$$

6.9 Enhanced Oil Recovery, Carbon Capture, and Geological Storage

As discussed in Section 6.3.10, carbon dioxide (CO_2) enhanced oil recovery (EOR) injects CO_2 into the field to stimulate oil production. Carbon capture separates, treats, and compresses a high purity CO_2 stream for transport to geological storage. In the geological storage, CO_2 is injected into onshore or offshore reservoirs such as oil and gas production fields, deep saline formations, or coal seams. Geological storage may occur solely for CO_2 storage or with EOR. For geological storage with EOR, the majority of the CO_2 produced with the oil is separated and reinjected into the fields. Overall, carbon capture utilization and storage (CCUS) is an option to reduce GHG emissions by its long-term isolation of CO_2 from the atmosphere.

6.9.1 Enhanced Oil Recovery

Broadly speaking, EOR includes all artificial methods of recovering oil after primary production, including thermal, chemical, or gas-miscible methods. As discussed in Section 6.3.10, during CO_2 EOR, CO_2 is injected into the formation via injection wells to effectively move the oil toward the production wells. Over time, the concentration of CO_2 being produced with the oil increases. The CO_2 is separated from the produced oil with the gas stream, removed in the acid gas removal process, compressed and reinjected in a closed loop system (also referred to as being ‘recycled’). As described in Section 6.3.10, the following potential CO_2 venting sources exist in CO_2 EOR operations:

- CO_2 EOR unstabilized crude storage tanks: Residual CO_2 entrained in the oil produced using CO_2 EOR is vented to the atmosphere in an atmospheric storage tank immediately downstream of the separator where the CO_2 flashes out of the liquid hydrocarbons, along with CH_4. These CO_2 emissions from tank flashing would be estimated using methodologies described in Section 6.3.9.
- EOR hydrocarbon liquids dissolved CO_2: Any CO_2 that remains entrained in the stabilized liquid hydrocarbons after storage tank flashing is lost to the atmosphere during the crude transportation and processing phases. See Equation 6-26 for estimating CO_2 emissions from EOR hydrocarbon liquids dissolved CO_2.
- EOR CO_2 Injection Pump Blowdown: EOR operations use compressors or pumps to inject supercritical phase CO_2 into reservoirs. For upsets or maintenance events, these high-pressure injection pumps may be blown down to atmospheric pressure, resulting in the release of the supercritical phase CO_2 in the pressurized system between isolation valves. See Equation 6-27 for estimating CO_2 emissions from EOR CO_2 injection pump blowdowns.

6.9.2 Carbon Capture

6.9.2.1 Carbon Capture for ‘Capture-Ready’ Sources

Some of the most concentrated sources of CO_2 present in oil and gas operations include vent streams from acid gas removal units treating CO_2-rich gas (e.g., the amine regenerator vent), and tailgas streams from steam methane reforming (SMR) processes in hydrogen production units (e.g., the tailgas stream from the Pressure Swing Absorber). High concentration sources of CO_2

like these examples are often referred to as being 'capture ready' because far less energy and processing is required to produce a purified CO_2 stream that is ready for compression and transport, compared to more dilute combustion exhaust streams.

These processes have been previously described as potential sources of venting CO_2 to the atmosphere (e.g., Section 6.5.2.2 for acid gas removal venting, Section 6.11.3 for hydrogen production), but they also represent potentially viable capture ready streams for reducing emissions through carbon capture utilization and storage (CCUS) projects. In carbon capture projects, the recovered CO_2-rich gas streams are treated to remove water and other impurities, and then compressed for transport to storage, EOR, or utilization as a feedstock for CCUS.

Other industrial processes, including cement, methanol, ammonia, and iron and steel manufacturing, also have high concentration CO_2 streams that are potential capture ready sources of CO_2 for CCUS projects.

Potential sources of vented emissions from carbon capture processes associated with AGR or SMR operations may include:

- Non-routine equipment blowdown: Vented CO_2 emissions from carbon capture equipment would occur primarily from non-routine blowdown events where equipment is evacuated due to process upsets or maintenance. CO_2 venting from equipment blowdowns can be estimated using Equation 6-27 for EOR CO_2 injection pump blowdown, using the estimated gas vent volume from the evacuated CO_2 compression or treatment equipment.

- Incomplete capture efficiency: Continuous vented emissions may occur if the capture of the AGR regenerator vent or SMR tailgas stream is incomplete (i.e., capture efficiency <100%). In this case, a mass balance approach should be used to estimate the amount of uncaptured CO_2 and CH_4 vented to the atmosphere or routed to a control device.

- CO_2 stream dehydration processes: Once captured from the vent stream, the CO_2 stream is treated to remove water and then compressed for transport to storage. The calculation methodologies in Section 6.3.8.1 for glycol dehydration and Section 6.3.8.2 for desiccant dehydration may be used to be estimate CO_2 and CH_4 emissions from these respective treatment steps in carbon capture system, if applicable. Use of the emission factors in those sections is not recommended due to the difference in composition between dehydrating a natural gas stream and an AGR regenerator vent that is primarily CO_2. If data are not available to quantify emissions, it is reasonable to assume that the methane emissions are negligible, and CO_2 would also be minimal due to low solubility of CO_2 in glycol.

- CO_2 stream compression: After the treatment of the captured CO_2 stream, it is compressed for transport to storage. The calculation methodologies and emission factors in Section 6.4.3 may be used to estimate CO_2 and CH_4 vented emissions from the compression step in the carbon capture system.

6.9.2.2 Carbon Capture for Combustion Sources

For carbon capture from combustion source exhaust, the process and energy requirements vary according to the technology employed for CO_2 capture. Because the CO_2 concentration in combustion exhaust is low, the energy requirements for carbon capture are typically quite large. For low emissions pathways, the energy requirement for carbon capture can be met through alternatives such as renewable energy solutions (e.g., solar or wind energy with battery storage).

Carbon capture technologies for combustion sources are typically classified by method:

- Pre-combustion carbon capture: This technique is the terminology used for fuel gasification to produce synthesis gas, comprised of H_2 and CO, which is subsequently oxidized to CO_2. This process, the initial stage of an integrated gasification combined cycle (IGCC) power plant, is fundamentally the same as the steam CH_4 reforming process in a refinery hydrogen process. The sources of vented emissions in the pre-combustion carbon capture process are the same as described above in Section 6.9.2.1 for hydrogen production tailgas capture.

  Another pre-combustion carbon capture technology is oxyfuel combustion, where purified oxygen is used instead of air in the combustion process, leading to a CO_2-rich exhaust gas, or capture-ready, stream. Oxyfuel combustion is energy intensive as it requires an air separation process to remove nitrogen from oxygen prior to combustion. The capture techniques, and consequently the associated vented emission sources, are the same as described in Section 6.9.2.1.

- Post-combustion carbon capture: CO_2 capture from combustion exhaust is referred to as post-combustion capture and many of the technologies use chemical solvents, such as amines, to separate CO_2 from the flue gas stream. Because of the low concentrations of CO_2 in exhaust gas, the capture processes are energy intensive compared to a capture-ready stream of high concentration CO_2. The amine process and associated vented sources are also discussed above in Section 6.9.2.1. More advanced carbon capture technologies are being developed that are less energy intensive.

6.9.3 Geological Storage

Although most (>99%) of the CO_2 injected into geological storage is expected to remain sequestered for over a thousand years, small amounts of CO_2 may leak from the geologic reservoir through the ground surface or sea bed and then to the atmosphere (sometimes referred to as seepage). This fugitive emission source is covered in Section 7.

6.10 Crude Oil Transport

The transportation segment consists of crude and natural gas transport from the production segment to downstream operations and the transport of refined products from refineries to marketing or distribution centers. The transportation of natural gas is covered in Section 6.6; this section covers the transport of crude and petroleum products. Transporting petroleum liquids via tank trucks, rail tank cars, and marine vessels, and the loading of petroleum products into these vessels, results in evaporative losses of the hydrocarbons. Hydrocarbon emissions occur during loading operations as the organic vapors in the cargo tanks are displaced into the atmosphere by the petroleum liquid that is being loaded. Evaporative hydrocarbon emissions can also occur during marine ballasting operations as crude oil loaded from a marine cargo vessel is replaced by "ballasting" water that can displace hydrocarbon vapors in the marine vessel. Transit losses occur due to a mechanism that is similar to storage tank breathing losses.

Due to the fact that there is no CH_4 or CO_2 in most petroleum products (including "weathered" crude), calculating evaporative emissions associated with loading, ballasting, and transit operations is likely to be immaterial, except in the case of "live" or "unstabilized" crude oil. Emissions can be estimated if measured CH_4 or CO_2 content data are available for "weathered" crude or other petroleum vapors. (Refer to Appendix D for more information on the CH_4 and CO_2 content of "weathered" crude and other petroleum products.) This section presents simple calculation approaches for these activities in crude service. More detailed methods and approaches for loading, ballasting, and transit operations for crude oil are provided in Appendix B.

Several approaches are available for estimating emissions from loading, ballasting, and transit operations. In many cases, the specific estimation approach depends on the type of liquid, type of information available, and other specific operating conditions. Each of the approaches calculates TOC emissions, which requires a vapor phase CH_4 (or CO_2, if present) content to convert to CH_4 (or CO_2) emissions. The vapor phase CH_4 content of "unstabilized" crude oil is assumed to be 15 wt% if site-specific data are not available, recognizing that this will overestimate emissions (EPA, AP-42 Section 5.2, 2008). Equations for calculating CH_4 emissions from TOC emission factors are provided in Section 7.1.3. As mentioned earlier, "weathered" crude and other petroleum products contain negligible CH_4 or CO_2, and thus would have no material evaporative losses of CH_4 or CO_2.

Note that if loading losses are routed to a combustion device such as a thermal oxidizer or VCU, the mass of vapors sent to the combustion device can be estimated using the methodology described in this section. Emissions from the combustion of the vapor should be calculated using the methodology described in Section 5.

6.10.1 Loading Loss Emissions – Truck and Marine

Table 6-47 provides simplified TOC emission factors for loading loss emissions for crude oil (EPA, AP-42 Section 5.2, 2008). TOC emissions should be converted to CH_4 (or CO_2, if present) emissions based on the CH_4 (or CO_2) content of the loading vapors. In the absence of measurement data, the assumption of 15 wt% CH_4 in the vapor phase for unstabilized crude can be assumed as previously discussed.

Table 6-47. Simplified TOC Emission Factors for Loading Losses

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

Footnotes and Sources:

[a] The factors shown are for total organic compounds. AP-42 reports that the VOC comprises approximately 85% of the TOC for crude oil. Thus, a simplifying assumption for the CH_4 content of the TOC is 15% in the absence of site-specific data, recognizing that this will likely overestimate emissions.

[b] EPA, AP-42, Section 5, Tables 5.2-5 and 5.2-6, 2008.

[c] The example crude oil has an RVP of 5 psia.

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

[e] 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/10^3 gallons.

[f] Marine loading factors based on a loaded liquid temperature of 60°F.

Exhibit 6-35 provides a sample calculation illustrating the use of the loading loss emission factors for crude oil loading.

EXHIBIT 6-35: Sample Calculation for Estimating Loading Loss CH_4 Emissions Using Simplified Emission Factor Approach

INPUT DATA:

50,000 bbl/yr of crude oil is loaded into rail tankers via splash loading and dedicated normal service. The crude vapors are estimated to contain 12 wt% CH_4, based on the crude composition using simulation modeling. Calculate the CH_4 emissions.

CALCULATION METHODOLOGY:

From Table 6-47, the emission factor corresponding to crude loading losses from rail splash loading, dedicated service is 2.20 tonnes TOC/million gallons loaded. The loading emissions are calculated by converting the TOC emissions to CH_4 and applying the annual loading rate, as shown below:

$$E_{CH_4} = \frac{2.20\text{ tonnes TOC}}{10^6\text{ gal}} \times \frac{42\text{ gal}}{\text{bbl}} \times \frac{50{,}000\text{ bbl}}{\text{yr}} \times \frac{12\text{ tonne }CH_4}{100\text{ tonne TOC}}$$

$$\underline{E_{CH_4} = 0.554\text{ tonnes }CH_4/\text{yr}}$$

6.10.2 Ballasting Emissions

Ballasting operations are used to improve the stability of empty tanker ships after their cargo tanks have been unloaded. After the 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.

Table 6-48 provides average emission factors for estimating TOC emissions from crude ballasting operations (EPA, AP-42 Table 5.2-4, 2008).

The emission factors are for TOC and should be converted to CH_4 (or CO_2, if present) emissions based on the CH_4 (or CO_2) content of the ballasting vapors. 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 of less than 5 feet prior to crude discharge (“ullage” refers to the distance between the cargo surface level and the deck level). The “lightered or previously short loaded” category applies to those cargoes that have an arrival ullage of more than 5 feet.

Exhibit 6-36 demonstrates the use of the crude oil ballasting emission factors.

Table 6-48. Average TOC Emission Factors for Crude Oil Ballasting Operations

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

Footnotes and Sources:

[a] EPA, AP-42, Section 5, Table 5.2-4, 2008.

[b] 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_4 content of the TOC is 15% in the absence of site-specific data, recognizing that this will likely overestimate emissions.

[c] 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/10^3 gallons.

[d] Based on assumed typical arrival ullage of 0.6 m (2 feet).

[e] Based on assumed typical arrival ullage of 6.1 m (20 feet).

[f] Typical overall situation based on the observation that 70% of tested compartments had been fully loaded before ballasting.

EXHIBIT 6-36: Sample Calculation for Crude Oil Ballasting Emissions Based on Unknown Ullage

INPUT DATA:

Crude oil (RVP 5) is unloaded from ships at a marine terminal. The annual ballast water throughput is 1 million bbl/year. The ullage of the arriving ships is unknown. Calculate the CH_4 emissions, assuming that the ballasting operations at this facility are typical.

CALCULATION METHODOLOGY:

TOC emissions are calculated using the emission factor provided in Table 6-48.

The ballasting TOC emissions are calculated by multiplying the ballasting emission factor by the annual ballast water throughput loaded into the ships. The TOC emissions must be multiplied by the CH_4 content of the vapors to obtain the CH_4 emissions. As a simplifying assumption, the CH_4 content of the vapors will be assumed to be 15 wt% per AP-42 (EPA, AP-42 Section 5.2, 2008). Thus, the CH_4 emissions from the ballasting operations are:

$$E_{CH_4} = \frac{1.1 \text{ lb TOC}}{10^3 \text{gal}} \times \frac{42 \text{ gal}}{\text{bbl}} \times \frac{1\times10^6 \text{ bbl}}{\text{yr}} \times \frac{15 \text{ lb } CH_4}{100 \text{ lb TOC}} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CH_4} = 3.14 \text{ tonnes } CH_4/\text{yr}}$$

6.10.3 Transit Loss Emissions

In addition to emissions resulting from loading operations and marine ballasting operations, hydrocarbon emissions also occur during petroleum transit. The mechanism resulting in transit losses is similar to breathing losses that occur for storage tanks. 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.

Table 6-49 provides simple transit TOC emission factors for marine transit of crude oil (EPA, AP-42 Section 5.2.2.1.3, 2008).

Table 6-49. Simplified TOC Emission Factors for Marine Transit Losses

Units		Crude Oil [a, b, c]
Original Units	lb TOC/week-10^3 gal transported	1.3
	mg TOC/week-L transported	150
Converted Units [d]	tonne TOC/week-10^6 gal transported	0.57
	tonne TOC/week-10^3 m^3 transported	0.150

Footnotes and Sources:

[a] 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_4 content of the TOC is 15% in the absence of site-specific data, recognizing that this will likely overestimate emissions.

[b] EPA, AP-42, Section 5, Table 5.2-6, 2008.

[c] The example crude oil has an RVP of 5 psia.

[d] 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/10^3 gallons.

Alternatively, the Australian Government Department of Climate Changes provides the following CO2e emission factor for crude oil transport (Australian Government, 2017):

8.7E-04 tonne CO_2e/tonne crude transported

Exhibit 6-37 illustrates the use of the simple crude oil transit emission factors.

EXHIBIT 6-37: Sample Calculation for Estimating CH_4 Emissions Using Simplified Transit Emission Factors

INPUT DATA:

500,000 barrels of crude oil (RVP 5) are transported via ships with an average trip duration of 10 days. The company transports the crude 25 times during the given reporting year. Calculate the CH_4 emissions using the AP-42 emission factors.

CALCULATION METHODOLOGY:

Transit loss emissions are calculated by multiplying the transit loss emission factor given in Table 6-49 for crude oil, by the volume transported and the CH_4 content of the vapors. As a simplifying assumption, the CH_4 content of the vapors is assumed to be 15 wt% (EPA, AP-42 Section 5.2, 2008).

$$E_{CH_4} = \frac{0.57 \text{ tonne TOC}}{\text{week-}10^6 \text{ gal transported}} \times \frac{42 \text{ gal}}{\text{bbl}} \times 500{,}000 \text{ bbl} \times \frac{10 \text{ days}}{\text{trip}} \times \frac{25 \text{ trips}}{\text{yr}}$$
$$\times \frac{\text{week}}{7 \text{ days}} \times \frac{15 \text{ lb } CH_4}{100 \text{ lb TOC}}$$

$$\underline{E_{CH_4} = 64.1 \text{ tonnes } CH_4/\text{yr}}$$

6.11 Refining

6.11.1 Catalyst Regeneration

6.11.1.1 Catalytic Cracking Unit

The catalytic cracking processes deposit coke on the catalyst as a byproduct of the reaction. That coke must be burned off to restore the activity of the catalyst. The coke is continuously burned off in the regenerator. This process vent may be a significant source of CO_2 emissions.

Fluid catalytic cracking units (FCCUs) are operated in two basic modes:

1. Full, or complete, CO burn mode, where essentially all CO is combusted to CO_2 within the regenerator. The exhaust gas typically contains approximately 2 % O_2 and less than 1% CO.

The hot exhaust gases often pass through a waste heat boiler, operated with or without supplemental fuel, to produce steam prior to exiting through the stack.

2. Partial burn mode, where the regenerator exhaust gas typically contains less than 1% O_2 and 6-8% CO (though these compositions can vary). The exhaust gases pass through a CO boiler, which completes the combustion of CO to CO_2 external to the FCCU regenerator before the gases exit the stack.

Sometimes an oxidation promoter (e.g., platinum, palladium, etc.) is added to the process or is included within the catalyst to assist combustion in "promoted" operation. Where no promoter is used, the operation is referred to as "conventional" or "non-promoted" CO burn. Full or partial CO burn modes can be conventional or promoted.

In some cases, the regenerator off-gas may be controlled with a CO boiler (to control CO and TOC emissions) if operated in a full or partial burn mode and/or with an electrostatic precipitator or scrubber (to control particulate emissions). When a partial burn unit is operated with a CO boiler, the unit is equivalent to a full burn unit with respect to CO_2, CH_4, and TOC emissions since the combustion of CO to CO_2 is completed. As noted earlier, some catalytic cracking unit (CCU) regenerators are designed to complete the combustion of CO to CO_2 and do not need a CO boiler. These units may also be equipped with a waste heat boiler that can be fired with supplemental fuel. The CO_2 from the combustion of the supplemental fuel should be accounted for as described in Section 4.

Figure 6-5 provides the decision tree for estimating emissions from FCCU regeneration. The commonly used approaches for estimating the CO_2 and CH_4 emissions from FCCU regeneration are based on either coke burn rate or flue gas flow rate (or air blower capacity) and composition.

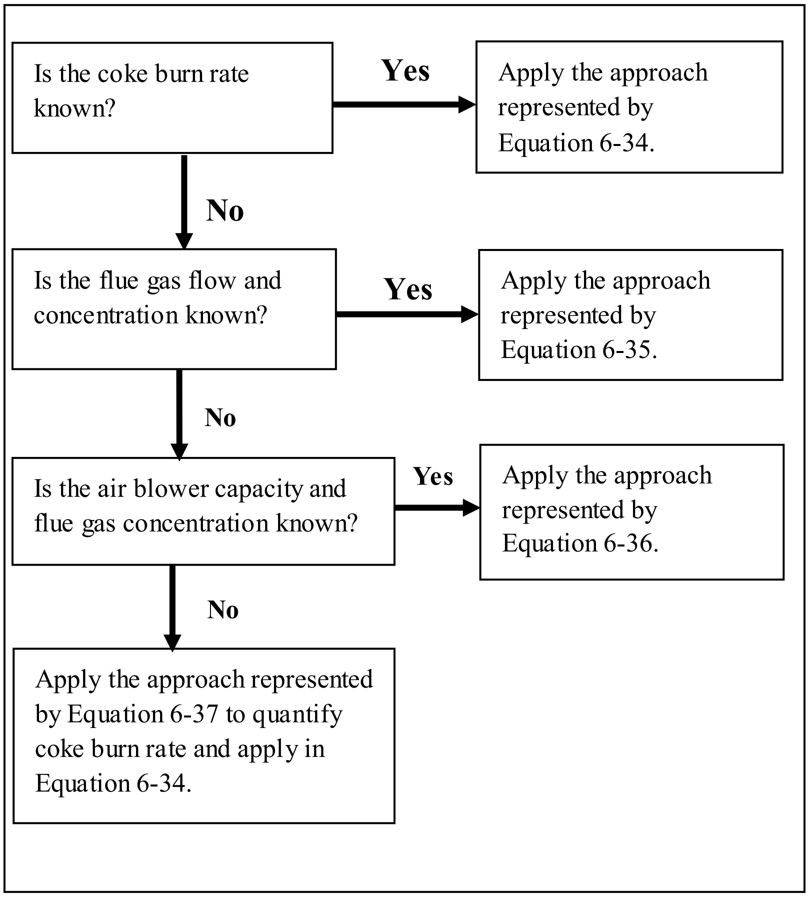

Figure 6-5. CO_2 Emissions from Fluid Catalytic Cracking Units (FCCU)

These approaches are based on process parameters that are generally monitored or estimated as part of routine refinery operations. The process calculation approaches should provide equally accurate emission estimates. The user should pick the approach for which the input data are most readily available and are expected to have the lowest uncertainty.

The first approach uses the coke burn rate expressed in mass per year. The coke burned is assumed to proceed completely to CO_2. Based on this assumption and accounting for the conversion of units, the CO_2 emission rate can be calculated from the following equation:

$$E_{CO_2} = CC_{Avg} \times CF \times \frac{44 \text{ mass units } CO_2/\text{mole}}{12 \text{ mass units C/mole}} \times T \qquad \text{(Equation 6-34)}$$

where:

E_{CO2} = Emissions of CO_2 in units of mass (pounds, kg, tonnes) per year;
CC_{Avg} = Daily average coke burn rate in units of average mass per day;
T = Annual operating time (days/year);
CF = Weight fraction of carbon in the coke burned (if unknown, refer to Table 3-8 or conservatively assume default = 1.0);
44 = Molecular weight of CO_2; and
12 = Molecular weight of carbon (coke is assumed to be carbon).

Equation 6-34 is based on the fundamental principles of complete stoichiometric combustion of the carbon in coke to CO_2. Using a site-specific carbon fraction of coke data will result in the most accurate estimates. In the absence of site-specific carbon fraction of coke data, the user may consult Table 3-8, which contains the properties of various fuels, or assume a carbon fraction of 1.0 as a simplifying assumption, recognizing that this will overestimate emissions. The mass balance approach in Equation 6-34 can be restated in terms of catalyst regeneration rate and weight fraction of carbon burned during catalyst regeneration. Refer to Equations 6-40 and 6-41 for continuous and intermittent catalyst regeneration, respectively.

If the coke burn rate is unknown, emissions can also be calculated using the flue gas flow and species concentration (also known as the "K_1, K_2, K_3 approach" provided in EPA Rule 40 CFR 63, Subpart UUU). This equation can be reduced to Equation 6-35. The full equation derivation is provided in Appendix B.

$$E_{CO_2} = \left[K_1 \times Q_r \times \left(P_{CO_2} + P_{CO}\right)\right] \times \frac{44 \text{ mass units } CO_2/\text{mole}}{12 \text{ mass units C/mole}} \times H \qquad \text{(Equation 6-35)}$$

where:

E_{CO_2} = Emissions of CO_2 (lb/year or kg/year);
K_1 = Carbon conversion factor burn term (0.0186 lb-min/hr-dscf-% or 0.2982 kg-min/hr-dscm-%, given in Table B-2);
Q_r = Volumetric flow rate of exhaust gas before entering the emission control system, calculated using Equation B-2 (dscf/min or dscm/min);
P_{CO_2}, P_{CO} = Percent CO_2 and CO concentrations, respectively, in regenerator exhaust, percent by volume (dry basis); and
H = Annual operating time (hrs/yr); 8760 hrs/yr if operating continuously throughout the year.

If the flue gas flow is unknown, as shown in Figure 6-5, a process calculation approach based on the air blower capacity and flue gas concentration can be used:

$$E_{CO_2} = (AR + SOR) \times (FCO_2 + FCO) \times \frac{44}{\text{molar volume conversion}} \times H \qquad \text{(Equation 6-36)}$$

where:

E_{CO_2} = Emissions of CO_2 in units of mass (pounds, kg, metric tonnes) per year;
AR = Air rate in standard cubic feet (scf) or standard cubic meters per minute, on a dry basis;

SOR = Supplemental oxygen rate (if used) in scf or standard cubic meters per minute, on a dry basis;
FCO_2 = Fraction CO_2 in the flue gas, on a volumetric, dry basis (enter "0.12" for 12%, not 12);
FCO = Fraction CO in the flue gas, on a volumetric, dry basis (enter "0.08" for 8%, not 8);
44 = Molecular weight of CO_2;
Molar volume conversion = Conversion from molar volume to mass (379.3 scf/lbmole or 23.685 Sm^3/kgmole at 14.7 psia and 60 °F); and
H = Annual operating time (min/yr); 525,600 min/yr if operating continuously throughout the year.

This equation is based on fundamental principles for calculating the mass of a component from the total stream flow and concentration of the subject component. The concentration term includes both CO and CO_2, because a partial oxidation regenerator flue gas contains both species, and each mole of CO will become a mole of CO_2 when emitted from the CO boiler.

If the flue gas flow, flue gas concentration, air blower capacity, and average coke burn rate are all unknown, the coke burn rate can be calculated based on the amount of feedstock, as provided in Equation 6-37. The calculated coke burn rate can then be applied to Equation 6-34 to determine CO_2 emissions, as identified in Figure 6-5. Equation 6-37 is derived from the US EPA's GHG Reporting Program, 40 CFR 98, Subpart Y (EPA, 2019a).

$$CC = Q_{unit} \times (CBF \times 0.001) \quad \text{(Equation 6-37)}$$

where:

CC = Daily average coke burn rate in units of average metric tonnes per day;
Q_{unit} = Daily average throughput of unit (bbl/day);
CBF = Coke burn-off factor from engineering calculations (kg coke per barrel of feed); default for catalytic cracking units = 7.3; default for fluid coking units = 11; and
0.001 = Conversion factor (metric tonne/kg).

An example for calculating CO_2 from FCCU catalyst regeneration using the alternative approaches is provided in Exhibit 6-38.

Additionally, some CH_4 and N_2O may be generated during the catalyst regeneration process and these emissions can be estimated using default emission factors relative to the amount of CO_2 emitted as shown in Equation 6-38 and Equation 6-39. Default factors for petroleum coke are listed in Table 4-3.

$$E_{CH_4} = \left(E_{CO_2} \times \frac{EF_{CH_4}}{EF_{CO_2}}\right) \quad \text{(Equation 6-38)}$$

where:

E_{CH_4} = Annual CH_4 emissions from coke burn-off (metric tonnes CH_4/year);

E_{CO_2} = Emission rate of CO_2 from coke burn-off calculated through the use of Equation 6-34 through Equation 6-37, converted to metric tonnes/year;

EF_{CO_2} = Default CO_2 emission factor for petroleum coke from Table 4-3 (tonnes CO_2/MMBtu); and

EF_{CH_4} = Default CH_4 emission factor for petroleum coke from Table 4-5 (tonnes CH_4/MMBtu).

$$E_{N_2O} = \left(E_{CO_2} \times \frac{EF_{N_2O}}{EF_{CO_2}}\right) \qquad \text{(Equation 6-39)}$$

where:

E_{N_2O} = Annual nitrous oxide emissions from coke burn-off (metric tonnes N_2O/year);

E_{CO_2} = Emission rate of CO_2 from coke burn-off calculated through the use of Equation 6-34, Equation 6-36, or Equation 6-37, converted to (metric tonnes/year);

EF_{CO_2} = Default CO_2 emission factor for petroleum coke from Table 4-3 (tonnes CO_2/MMBtu); and

EF_{N_2O} = Default N_2O emission factor for petroleum coke" from Table 4-5 (tonnes N_2O /MMBtu).

EXHIBIT 6-38: Sample Calculation for FCCU Process CO_2 Calculation Approach

INPUT DATA:
Assume a 6.36×10^3 m^3 per day catalytic cracking unit has a coke burn rate of 119,750 tonnes per year and a blower air capacity of 2150 m^3/min. Assume also that the carbon fraction of the coke is 0.93 based on site-specific data; the flue gas concentrations are 11% CO_2 and 9% CO exiting the regenerator; and that a CO boiler is used for control of that stream. Supplemental firing with natural gas is also employed (100×10^6 Btu/hr, higher heating value basis). Calculate the regenerator CO_2 emissions using Equation 6-34, Equation 6-36, and Equation 6-37. Calculate the emissions from supplemental firing of natural gas. Summarize the FCCU emissions.

CALCULATION METHODOLOGY:

1. *Calculate the CO_2 emissions using Equation 6-34.* Using Equation 6-34, the estimated CO_2 emissions from the regenerator would be:

$$E_{CO_2} = 119{,}750 \frac{\text{tonnes Coke Burned}}{\text{year}} \times \frac{0.93 \text{ tonnes C}}{\text{tonnes Coke}} \times \frac{44 \text{ tonnes } CO_2}{12 \text{ tonnes C}}$$

$$\underline{E_{CO_2} = 408{,}348 \text{ tonnes } CO_2\text{/year}}$$

2. *Calculate the CO_2 emissions using Equation 6-36.* Using the air rate in Equation 6-36, the CO_2 emission estimate is:

$$E_{CO_2} = \left[\frac{0.2982 \text{ kg - min}}{\text{hr - dscm \%}} \times \frac{2{,}150 \text{ dscm}}{\text{min}} \times (11\% + 9\%)\right] \times \frac{44}{12} \times \frac{\text{tonne}}{1{,}000 \text{ kg}} \times \frac{8760 \text{ hr}}{\text{yr}}$$

$$\underline{E_{CO_2} = 411{,}862 \text{ tonnes } CO_2\text{/yr}}$$

EXHIBIT 6-38: Sample Calculation for FCCU Process Calculation Approach, continued

3. *Calculate the* CO_2 *emissions using Equation 6.-37.* Using the air rate in Equation 6-37 yields:

$$E_{CO_2} = \frac{2150\ m^3}{min} \times \left(\frac{0.11\ m^3\ CO_2}{m^3\ gas} + \frac{0.09\ m^3\ CO}{m^3\ gas} \times \frac{m^3\ CO_2}{m^3\ CO} \right) \times \frac{44\ kg\ CO_2/kgmole\ CO_2}{23.685\ m^3\ CO_2/kgmole\ CO_2}$$

$$\times \frac{525{,}600\ min}{year} \times \frac{tonnes}{1000\ kg}$$

$$\underline{E_{CO_2} = 419{,}859\ tonnes\ CO_2/year}$$

4. *Calculate the emissions from supplemental natural gas firing.* The emissions from the supplemental firing are in addition to the CO_2 emissions from the FCCU regenerator. Emissions from the supplemental firing of natural gas are estimated using the approaches presented in Section 5. The CO_2 emission factor was taken from Table 4-3 for pipeline natural gas. The CH_4 and N_2O emission factors were taken from Table 4-7 for natural gas-fired boilers.

$$E_{CO_2} = \frac{100 \times 10^6\ Btu}{hr} \times \frac{0.0531\ tonne\ CO_2}{10^6 Btu} \times \frac{8760\ hr}{yr}$$

$$\underline{E_{CO_2} = 46{,}516\ tonnes\ CO_2\ /\ yr}$$

1)

$$E_{CH_4} = \frac{100 \times 10^6\ Btu}{hr} \times \frac{1.0 \times 10^{-6}\ tonne\ CH_4}{10^6\ Btu} \times \frac{8760\ hr}{yr}$$

$$\underline{E_{CH_4} = 0.88\ tonnes\ CH_4\ /\ yr}$$

$$E_{N_2O} = \frac{100 \times 10^6\ Btu}{hr} \times \frac{9.8 \times 10^{-7}\ tonne\ N_2O}{10^6\ Btu} \times \frac{8760\ hr}{yr}$$

$$\underline{E_{N_2O} = 0.86\ tonnes\ N_2O\ /\ yr}$$

EXHIBIT 6-38: Sample Calculation for FCCU Process Calculation Approach, continued

5. *Summarize the FCCU emissions*. The emissions from the FCCU are summarized below.

Coke burn rate approach (Equation 6-34)	**Contribution**	**CO_2**	**CH_4**	**N_2O**
	Coke Burn	408,348	12.04	2.40
	CO Boiler	46,516	0.88	0.86
	Total	454,149	0.88	0.86
“K_1, K_2, K_3” approach (Equation 6-35),	Contribution	CO_2	CH_4	N_2O
	Coke Burn	411,862	12.14	2.45
	CO Boiler	46,516	0.88	0.86
	Total	458,663	0.88	0.86
Air blower rate approach (Equation 6-36)	Contribution	CO_2	CH_4	N_2O
	Coke Burn	419,859	12.38	2.47
	CO Boiler	46,516	0.88	0.86
	Total	466,660	0.88	0.86

6.11.1.2 Other Catalyst Regenerator

A variety of other refinery processes employ catalysts that require regeneration (e.g., naphtha reformers, hydroprocessing units). Most of these processes use intermittent regeneration, although a few have continuous regeneration systems. The primary source of emissions is from the combustion of coke on the spent catalyst that results in CO_2 emissions. The CO_2 emissions from intermittent regeneration are not likely to be significant when compared to combustion sources and continuous regeneration.

Emissions can be calculated using similar methods listed for the FCCU. Additionally, using the fundamental principle of complete stoichiometric combustion, CO_2 emissions from continuous or intermittent catalyst regeneration can be estimated by Equation 6-40 or Equation 6-41, respectively. Both equations can also be used for catalytic reformer units (CRUs). Emissions from all other coke combustion on spent catalysts can be calculated assuming complete conversion to CO_2. A default carbon content for petroleum coke is presented in Table 3-8; all other coke types can be assumed to be 100% carbon.

$$E_{CO_2} = CRR \times H \times \left(FC_{spent} - FC_{regen}\right) \times \frac{44 \text{ mass units } CO_2\text{/mole}}{12 \text{ mass units C/mole}} \qquad \text{(Equation 6-40)}$$

where:

E_{CO_2} = Emissions of CO_2 in tonnes per year;
CRR = Catalyst regeneration rate in tonnes per hour;
H = Hours that the regenerator was operational during the year (hrs/yr);
FC_{spent} = Weight fraction of carbon on spent catalyst; and
FC_{regen} = Weight fraction of carbon on regenerated catalyst.

In the absence of site specific data, FC_{regen} can be assumed to be zero, recognizing that this will overestimate emissions. This calculation is illustrated in Exhibit 6-39.

EXHIBIT 6-39: Sample Calculation for Other Continuous Catalyst Regeneration

INPUT DATA:
A catalytic reformer operates with a catalyst circulation rate of 10 tonnes per hour and with 4 wt% carbon on the spent catalyst. The unit operates for 8,280 hours per year. Calculate the CO_2 emissions.

CALCULATION METHODOLOGY:
Using Equation 6-40, the estimated CO_2 emissions are calculated as follows:

$$E_{CO_2} = \frac{10 \text{ tonnes catalyst}}{\text{hr}} \times \frac{8280 \text{ hr}}{\text{yr}} \times \frac{0.04 \text{ tonne C}}{\text{tonne catalyst}} \times \frac{44 \text{ tonne } CO_2\text{/tonne mole}}{12 \text{ tonne C/tonne mole}}$$

$$\underline{E_{CO_2} = 12{,}144 \text{ tonnes } CO_2\text{/yr}}$$

Similarly, the catalyst regeneration rate (CRR) for an intermittent regeneration operation consists of the catalyst inventory in tonnes multiplied by the number of regeneration events per year.

$$E_{CO_2} = CRR \times N \times \left(FC_{spent} - FC_{regen}\right) \times \frac{44 \text{ mass units } CO_2\text{/mole}}{12 \text{ mass units C/mole}} \qquad \text{(Equation 6-41)}$$

where:

E_{CO_2} = Emissions of CO_2 in tonnes per year;
N = Number of regeneration cycles per year;
CRR = Catalyst regeneration rate in tonnes per cycle;
FC_{spent} = Weight fraction of carbon on spent catalyst; and
FC_{regen} = Weight fraction of carbon on regenerated catalyst.

An example of this calculation is presented in Exhibit 6-40.

EXHIBIT 6-40: Sample Calculation for Other Intermittent Catalyst Regeneration

INPUT DATA:
A hydrotreater has a catalyst inventory of 1000 tonnes and the carbon on the spent catalyst is 7 weight percent (or 0.07 weight fraction). The catalyst is regenerated twice a year, on average.

Calculate the CO_2 emissions.

CALCULATION METHODOLOGY:
The estimated CO_2 emissions are calculated using Equation 6-41.

$$E_{CO_2} = \frac{1{,}000 \text{ tonnes catalyst}}{\text{regeneration}} \times \frac{2 \text{ regenerations}}{\text{yr}} \times \frac{0.07 \text{ tonne C}}{\text{tonne catalyst}} \times \frac{44 \text{ tonne } CO_2\text{/tonne mole}}{12 \text{ tonne C/tonne mole}}$$

$$\underline{E_{CO_2} = 513 \text{ tonnes } CO_2\text{/yr}}$$

The same methodology to derive CH_4 and N_2O emissions from the FCCU can be used for other catalyst regeneration processes. Refer to Equation 6-38 and Equation 6-39.

6.11.2 Cokers

Coking is another cracking process used at a refinery to generate transportation fuels, such as gasoline and diesel, from lower-value fuel oils. A desired by-product of the coking reaction is petroleum coke, which can be used as a fuel for power plants as well as a raw material for carbon and graphite products. Varieties of cokers are used in refineries, including delayed cokers, flexi-cokers, and fluid cokers.

- Fluid cokers employ a thermal cracking process which utilizes a fluidized solids technique to remove carbon (coke) for continuous conversion of heavy, low-grade oils into lighter products. The coke removal process for fluid cokers is similar to the catalyst regeneration process in a catalytic cracking unit; CO_2 emissions from the coke burner are estimated by assuming that all of the carbon in the coke is oxidized to CO_2, as shown in Equation 6-34. An example calculation for a fluid coker is shown in Exhibit 6.11-4.
- Flexi-cokers produce a low-Btu gas that is combusted through a fuel gas system or a flare, and typically will not have CO_2 emissions other than those calculated for the combustion sources described in Section 4. Equation 6-34 can also be used for flexi-coker emissions, provided that the combustion of the low-Btu gas is not otherwise accounted for (e.g., routed to and accounted for in flare emissions, or routed to fuel gas system and accounted for in plant-wide combustion emissions).

- Delayed cokers will not have CO_2 emissions other than from their process heaters that are calculated as any other combustion source (as described in Section 4). Emissions of CH_4 can occur from delayed decoking operations (venting, draining, deheading, and coke-cutting), which can be determined based on the mass of steam generated and released per decoking cycle and the number of decoking cycles using Equation 6-42.

$$E_{CH_4} = M_{steam} \times EF_{DCU} \times N \times 0.001 \qquad \text{(Equation 6-42)}$$

where:

E_{CH_4} = Annual CH_4 emissions from the delayed coking unit decoking operations (metric tonne/year);
M_{steam} = Mass of steam generated and released per decoking cycle (metric tonnes/cycle)
EF_{DCU} = CH_4 content for delayed coking unit (kg CH_4/metric tonnes steam) from unit-specific measurement data; if you do not have unit-specific measurement data, use the simplified emission factor of 7.9 kg CH_4/metric tonne steam;
N = Cumulative number of decoking cycles (or coke-cutting cycles) for all delayed coking unit vessels associated with the delayed coking unit during the year; and
0.001 = Conversion factor (metric tonne/kg).

If the amount of steam generated and released during decoking is unknown, it can be estimated using Equation 6-43 through Equation 6-47. First, the mass of coke in the delayed coking unit vessel at the end of the coking cycle can be calculated based on coke bed density and vessel dimensions using Equation 6-43.

$$M_{coke} = \rho_{bulk} \times \left[\left(H_{drum} - H_{outage} \right) \times \frac{\pi \times D^2}{4} \right] \qquad \text{(Equation 6-43)}$$

where:

M_{coke} = Typical dry mass of coke in the delayed coking unit vessel at the end of the coking cycle (metric tonnes/cycle);
ρ_{bulk} = Bulk coke bed density (metric tonnes per scftonnes/scf), use simplified factor of 0.0191 tonne/scf when site specific data is not available;
H_{drum} = Internal height of delayed coking unit vessel (feet);
H_{outage} = Typical distance from the top of the coking unit vessel to the top of the coke bed (*i.e.*, coke drum outage) at the end of the coking cycle (feet) from company records or engineering estimates; and
D = Diameter of delayed coking unit vessel (feet).

Next, the mass of water in the delayed coking unit vessel is calculated using Equation 6-44.

$$M_{water} = \rho_{water} \times \left[(H_{water}) \times \frac{\pi \times D^2}{4} - \frac{M_{coke}}{\rho_{particle}} \right] \qquad \text{(Equation 6-44)}$$

where:

M_{water} = Mass of water in the delayed coking unit vessel at the end of the cooling cycle just prior to atmospheric venting (metric tonnes/cycle);
ρ_{water} = Density of water at average temperature of the delayed coking unit vessel at the end of the cooling cycle just prior to atmospheric venting (tonnes/scf), when site specific data is not available assume simplified factor of 0.0270 tonnes/scf;
H_{water} = Typical distance from the bottom of the coking unit vessel to the top of the water level at the end of the cooling cycle just prior to atmospheric venting (feet) from design specifications or engineering estimates;
M_{coke} = Typical dry mass of coke in the delayed coking unit vessel at the end of the coking cycle (metric tonnes/cycle)
$\rho_{particle}$ = Particle density of coke (metric tonnes/scf), when site specific data is not available assume simplified factor of 0.0382 tonnes/scf; and
D = Diameter of delayed coking unit vessel (feet).

To calculate the average temperature of the delayed coking unit when the drum is first vented to the atmosphere, Equation 6-45 or Equation 6-46 may be used, depending on available data.

$$T_{initial} = (T_{overhead} + T_{bottom})/2 \qquad \text{(Equation 6-45)}$$

where:

$T_{initial}$ = Average temperature of the delayed coking unit vessel when the drum is first vented to the atmosphere (°F);
$T_{overhead}$ = Temperature of the delayed coking unit vessel overhead line measured as near the coking unit vessel as practical just prior to venting to the atmosphere; if the temperature of the delayed coking unit vessel overhead line is less than 216°F, use $T_{overhead}$ = 216°F; and
T_{bottom} = Temperature of the delayed coking unit vessel near the bottom of the coke bed; if the temperature at the bottom of the coke bed is less than 212°F, use T_{bottom} = 212°F.

$$T_{initial} = -0.039\ P_{overhead}^2 + 3.13\ P_{overhead} + 220 \qquad \text{(Equation 6-46)}$$

where:

$T_{initial}$ = Average temperature of the delayed coking unit vessel when the drum is first vented to the atmosphere (°F); and
$P_{overhead}$ = Pressure of the delayed coking unit vessel just prior to opening the atmospheric vent (pounds per square inch gauge, psig).

The results from Equations 6-43 through Equation 6-46 are used below in Equation 6-47 to calculate the mass of steam generated and released per decoking cycle.

$$M_{steam} = \frac{(1-f_{ConvLoss})\times(M_{water}\times C_{p,water}+M_{coke}\times C_{p.coke})\times(T_{initial}-T_{final})}{\Delta H_{vap}} \qquad \textbf{(}\text{Equation 6-47}\textbf{)}$$

where:

M_{steam} = Mass of steam generated and released per decoking cycle (metric tonnes/cycle);

$f_{ConvLoss}$ = Fraction of total heat loss that is due to convective heat loss from the sides of the coke vessel (unitless); when site specific data is not available assume simplified factor of 0.10;

M_{water} = Mass of water in the delayed coking unit vessel at the end of the cooling cycle just prior to atmospheric venting (metric tonnes/cycle);

$C_{p,water}$ = Heat capacity of water (British thermal units per metric tonne per degree Fahrenheit; Btu/tonne-°F); use the default value of 2,205 Btu/tonne-°F;

M_{coke} = Typical dry mass of coke in the delayed coking unit vessel at the end of the coking cycle (tonnes/cycle)

$C_{p,coke}$ = Heat capacity of petroleum coke (Btu/tonne-°F); when site specific data is not available assume default factor of 584 Btu/tonne-°F;

$T_{initial}$ = Average temperature of the delayed coking unit vessel when the drum is first vented to the atmosphere (°F)

T_{final} = Temperature of the delayed coking unit vessel when steam generation stops (°F); or assume a default value of 212°F; and

ΔH_{vap} = Heat of vaporization of water (British thermal units per metric tonne; Btu/tonne); or assume the default value of 2,116,000 Btu/tonne.

Note that if the coke burner off-gas is exported for recovery of CO_2, direct CO_2 emissions from the coker may be eliminated or reduced. As stated previously, if the coke burner off-gas is burned as a low-Btu fuel gas, the CO_2 present in the stream should be counted as combustion exhaust emissions and not as process venting.

EXHIBIT 6-61: Sample Calculation for Fluid Coker

INPUT DATA:
A fluid coker combusts 140×10^6 pounds per year of coke in the coke burner. The weight percent H_2 in the coke is known to be 1.5% (0.015 on a fraction basis). Calculate the CO_2 emissions.

CALCULATION METHODOLOGY:
The carbon fraction is equal to 1 minus the non-hydrocarbon fraction. In this example, the carbon fraction is assumed to be equal to 1 minus the fraction H_2, or 0.985. Using Equation 6-34, the estimated CO_2 emissions are:

$$E_{CO_2} = \frac{140\times10^6 \text{ lb Coke}}{\text{year}} \times \frac{0.985 \text{ lb C}}{\text{lb Coke}} \times \frac{44 \text{ lb CO}_2\text{/lbmole}}{12 \text{ lb C/lbmole}} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CO_2} = 229{,}350 \text{ tonnes CO}_2\text{/yr}}$$

6.11.3 Refinery Hydrogen Plant

Refinery hydrogen plants, often referred to as steam reformers, react hydrocarbons with steam (H_2O) to produce H_2 through a multiple step process involving catalytic reforming followed by water-gas-shift reaction and CO_2 removal. Steam reformers are not to be confused with naphtha reformers, the emissions from which are discussed in Section 6.11.1.2. The quantity of H_2 generated depends on the carbon-to-hydrogen ratio of the feed gas and the steam-to-carbon ratio. In most cases, H_2 is made from natural gas, but there are some plants that operate with naphtha or refinery fuel gas as the feedstock. The overall chemical reaction can be expressed as:

$$C_xH_{(2x+2)} + 2xH_2O \rightarrow (3x+1)H_2 + xCO_2 \qquad \text{(Equation 6-48)}$$

This equation shows that a mole of CO_2 is formed for every mole of carbon in the hydrocarbon species. Note that the CO_2 generated by this reaction does not include CO_2 emissions from process heater(s) associated with the H_2 plant. Emissions from the process heaters should be treated like other combustion sources described in Section 4.

After the shift reactor, hydrogen must be separated from the syngas. Older hydrogen plants purify the raw hydrogen using wet scrubbing followed by methanation. The wet scrubbing unit generates a nearly pure stream of CO_2 which may be further processed for other uses (including being sold as a product), or may be vented directly to the atmosphere. Some plants may monitor the flow rate and composition of the vent stream from the hydrogen plant; in this situation, these data can be used to estimate the vented emissions from the hydrogen plant.

Modern hydrogen plants use a cyclical pressure swing adsorption (PSA) unit instead of wet scrubbing to remove impurities (CO_2, CO, CH_4) from raw hydrogen exiting the shift reactor. Compared to older units, which are typically able to produce hydrogen of 90% to 98% purity, PSA units are capable of producing hydrogen with a purity of greater than 99% (Kunz et al. n.d.). The PSA purge or tail gas is a low-Btu fuel gas consisting mostly of CO_2, CO, and CH_4, and some H_2. The purge gas is then routed to the reformer furnace. The purge gas is noted to provide 50 to 90% of the heat input to the furnace, for one example process (UOP, 2002). Because the purge gas is sent to the reformer furnace, hydrogen plants with a PSA unit emit all GHGs as reformer furnace flue gas.

GHG emissions from combustion of the low-Btu gas, along with any supplemental fuels, should be estimated like other combustion sources, as presented in Section 4. Due to the variable composition of the PSA purge gas stream, the material balance approach is suggested for estimating emissions from the combustion of the PSA purge gas. Site specific data (e.g., PSA purge gas flow rate and composition) should be used in the material balance approach, due to the fact that the carbon content of the PSA purge gas is not similar to the carbon content of other typical fuels such as natural gas. For plants with a PSA unit, careful accounting must be taken to avoid representing emissions as from both the reaction process (conversion to CO_2 in the reformer and shift reactor) and from combustion of supplemental fuel sent to reformer furnace.

Hydrogen plants are often the preferred source of CO_2 for industrial uses (food and beverage, dry ice, etc.). Traditionally, hydrogen plants with wet scrubbing purification are desirable for this as the wet scrubbing purification process produces a near pure CO_2 stream. Where this type of plant is not available, operators of a PSA type hydrogen plant may choose to add a CO_2 removal step in conjunction with the PSA to capture a portion of the process CO_2 for offsite use. The CO_2 removed in this step should be calculated and included in emissions reporting.

Figure 6-6 illustrates the approaches for estimating CO_2 emissions from a refinery hydrogen plant.

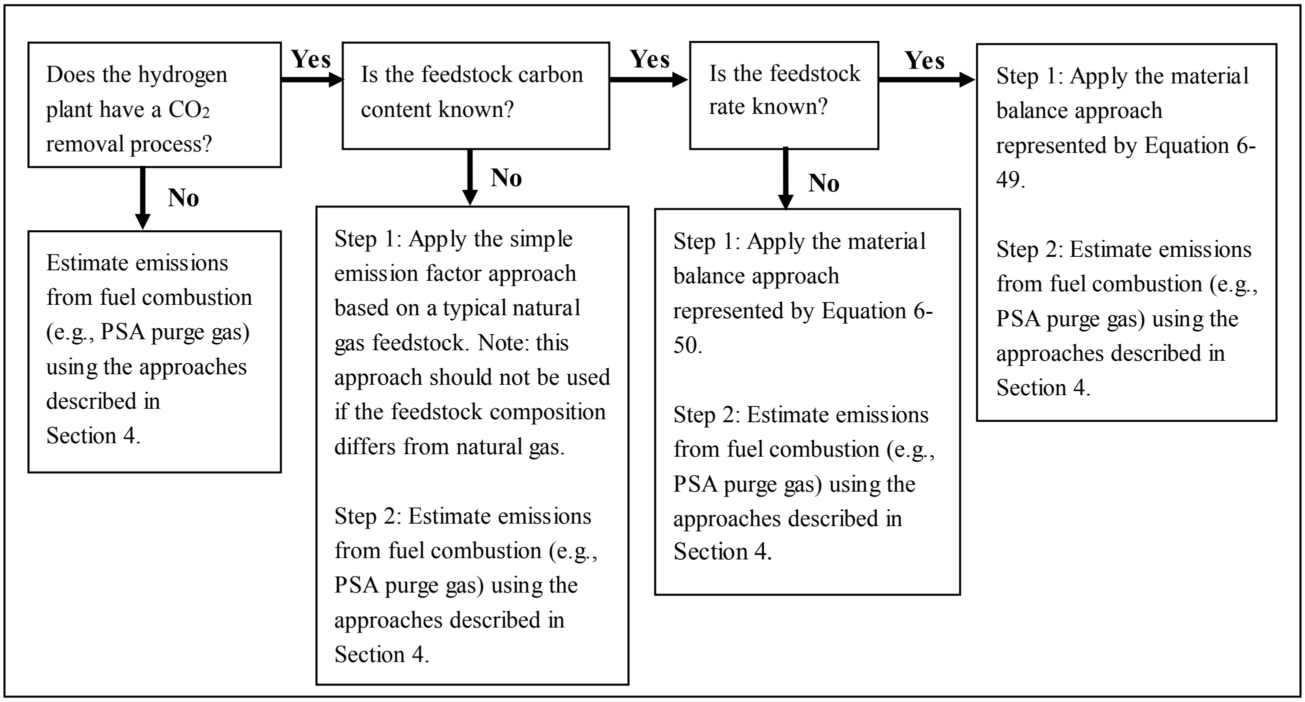

Figure 6-6. CO_2 Emissions from a Refinery Hydrogen Plant

A rigorous calculation approach, using a specific feed gas composition, can be used to estimate vented CO_2 emissions from the hydrogen plant. The rigorous approach can be based on either the volume of feedstock used or the hydrogen production rate. Both of these methods are discussed in this section, along with examples of their application.

There is also a simpler approach that can be used for hydrogen plants. Simple CO_2 emission factors have been developed from an assumed natural gas feedstock composition. The simple approach may be adequate for some refineries where the feed gas is similar to pipeline-quality natural gas (i.e., predominantly CH_4 with small amounts of other low molecular weight hydrocarbons). However, the more rigorous approaches should be used when the feed gas does not resemble natural gas or a more accurate estimation approach is desired.

The first of the two rigorous approaches is based on a material balance using the feedstock rate and carbon content. Equation 6-49 presents this material balance approach:

$$E_{CO_2} = FR \times CF \times \frac{44 \text{ mass units } CO_2\text{/mole}}{12 \text{ mass units C/mole}} \quad \text{(Equation 6-49)}$$

where:

E_{CO_2} = Emissions of CO_2 in units of mass (pounds, kg, tonnes) per year;
FR = Feedstock rate in units of mass per year (feedstock rate excluding H_2O fed);
CF = Weight fraction of carbon in feedstock;
44 = Molecular weight of CO_2; and
12 = Molecular weight of carbon.

The carbon fraction can be estimated using the feedstock composition if it is not explicitly known. Note that if the fraction of carbon in the feedstock (CF) includes carbon accounted for through other end uses (e.g., combustion of PSA purge gas), these emissions will be double counted. To avoid double counting, the quantity of carbon accounted for elsewhere should be subtracted from the feedstock rate. Exhibit 6-42 demonstrates the approach to estimate the CO_2 emissions from a hydrogen plant using the feedstock rate and carbon content.

EXHIBIT 6-42: Sample Calculation for Hydrogen Plant - Rigorous Approach based on Feedstock Rate and Carbon Content

INPUT DATA:
A hydrogen plant has a feedstock rate of 5×10^9 scf/yr using feed gas with the following composition (molar basis):

CH_4 = 85%, C_2H_6 = 8%, C_4H_{10}= 3%; the balance is inerts (assume N_2 for the inerts).

Calculate the CO_2 emissions.

CALCULATION METHODOLOGY:
CO_2 emissions are calculated using Equation 6-49. The first step in calculating the CO_2 emissions is to estimate the carbon content of the feed gas since it is not explicitly provided. In order to calculate the carbon content of the feed gas, the molecular weight of the mixture, weight percents of the individual components, and individual carbon contents must be calculated.

The molecular weight of the mixture shown in the table below is estimated using Equation 3-8, as demonstrated in Exhibit 3.3. The weight percent for each compound is estimated using Equation 3-7, rearranged in terms of weight percent. This calculation is demonstrated in Exhibit 3.4.

The carbon content in weight percent for each chemical species is calculated using Equation 4-9. Once the individual compound weight percents and carbon contents have been estimated, the feed gas mixture carbon content is estimated using Equation 4-10. These conversions are demonstrated in Exhibit 4.4(a).

The results of these calculations are shown below.

Compound	Mole %	MW	Weight %	Carbon Content (Wt. % C)
CH_4	85	16	72.1	75.0
C_2H_6	8	30	12.7	80.0
C_4H_{10}	3	58	9.2	82.8
N_2	4	28	5.9	0
Mixture	**100**	**18.86**	**~100**	**71.85**

After the feed stock gas mixture molecular weight and carbon content are defined, the CO_2 vent rate can be calculated using Equation 6-49:

$$E_{CO_2} = 5{,}000 \frac{10^6 \text{ scf feed}}{\text{year}} \times \frac{\text{lbmole feed}}{379.3 \text{ scf}} \times \frac{18.86 \text{ lb feed}}{\text{lbmole feed}} \times \frac{0.7185 \text{ lb C}}{\text{lb feed}} \times \frac{44 \text{ lb } CO_2}{12 \text{ lb C}} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CO_2} = 297{,}100 \text{ tonnes } CO_2/\text{yr}}$$

The other rigorous approach is based on the H_2 production rate rather than the feedstock rate. This second approach applies the stoichiometric ratio of H_2 formed to CO_2 formed, as shown in Equation 6-50 based on re-arranging Equation 6-48. For this approach, it is important to apply the total hydrogen production rate prior to any process slip stream to avoid underestimating emissions.

It is important to note that when refinery gas is used as a feedstock, Equation 6-50 should not be used (without modification). Refinery fuel gas typically contains hydrogen, and this "free" hydrogen passes through the process without producing any attendant CO_2 emissions. Thus, this methodology based on hydrogen production rate would tend to overestimate CO_2 emissions when refinery fuel containing hydrogen is used as a feedstock.

$$E_{CO_2} = H_2R \times \frac{x \text{ mole } CO_2}{(3x+1) \text{ mole } H_2} \times \frac{44}{\text{molar volume conversion}} \qquad \text{(Equation 6-50)}$$

where:

E_{CO_2} = Emissions of CO_2 in units of mass (pounds, kg, tonnes) per year;
H_2R = Rate of hydrogen production in units of volume (scf, m^3) per year;
x = Stoichiometry from Equation 6-48;
44 = Molecular weight of CO_2; and
Molar volume conversion = Conversion from molar volume to mass (379.3 scf/lbmole or 23.685 Sm^3/kgmole).

This second rigorous approach is demonstrated in Exhibit 6-43.

EXHIBIT 6-43: Sample Calculation for Hydrogen Plant - Rigorous Approach based on H_2 Production Rate

INPUT DATA:
A hydrogen plant produces 13×10^9 scf of hydrogen per year using feed gas with the following composition:

CH_4 = 85%, C_2H_6 = 8%, C_4H_{10}= 3%; the balance is inerts.

Calculate the CO_2 emissions.

CALCULATION METHODOLOGY:
The first step is to examine the chemical reaction for each compound:

CH_4: $CH_4+2H_2O = 4H_2+1CO_2$
C_2H_6: $C_2H_6+4H_2O = 7H_2+2CO_2$
C_4H_{10}: $C_4H_{10}+8H_2O = 13H_2+4CO_2$

Next, the moles of carbon and hydrogen are determined by multiplying the number of molecules of each in each compound by the composition of each compound in the feed gas (i.e., CH_4, C_2H_6, and C_4H_{10}). These results are used to determine the ratio of moles of carbon to moles of H_2, and are shown in the table below.

Compound	# C Atoms	# H_2 Molecules	Concentration	Moles C	Moles H_2
CH_4	1	4	0.85	0.85	3.4
C_2H_6	2	7	0.08	0.16	0.56
C_4H_{10}	4	13	0.03	0.12	0.39
Total Moles				**1.13**	**4.35**

To use Equation 6-50, the carbon to hydrogen ratio must be calculated. The carbon to hydrogen ratio is calculated by dividing the total moles C by the total moles H_2 (1.13/4.35 = 0.26). Since each mole of carbon produces 1 mole of CO_2, the CO_2/H_2 ratio is the same as the C/H_2 ratio (0.26).

The CO_2 vent rate can then be calculated using Equation 6-50:

$$E_{CO_2} = 13{,}000 \frac{10^6 \text{ scf } H_2}{\text{year}} \times \frac{\text{lbmole } H_2}{379.3 \text{ scf}} \times \frac{0.26 \text{ lbmole } CO_2}{\text{lbmole } H_2} \times \frac{44 \text{ lb } CO_2}{\text{lbmole } CO_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CO_2} = 177{,}800 \text{ tonnes } CO_2/\text{yr}}$$

A simpler approach to estimate CO_2 emissions from hydrogen plants with a CO_2 vent is to use default emission factors that are based on either feedstock consumption or hydrogen production. These emission factors are based on a stoichiometric conversion (as shown in Equation 6-48) for a feed gas with an average natural gas composition. Table 6-50 provides the average natural gas composition used to derive these factors, which is based on measurements from pipeline-quality gas from 26 U.S. cities (GTI, 1992).

Table 6-50. Composition of U.S. Pipeline-Quality Natural Gas

Compound	Average Volume % [a, b]
CH_4	93.07
C_2H_6	3.21
C_3H_8	0.59
Higher hydrocarbons [c]	0.32
Non-hydrocarbons [d]	2.81

Footnotes and Sources:

[a] Gas Technology Institute (GTI). Database as documented in W.E. Liss, W.H. Thrasher, G.F. Steinmetz, P. Chowdiah, and A. Atari, "Variability of Natural Gas Composition in Select Major Metropolitan Areas of the United States", GRI-92/0123, March 1992.

[b] Perry and Green. *Perry's Chemical Engineer's Handbook*, Sixth Edition, Table 9-14, 1984.

[c] Higher molecular weight hydrocarbons were represented by C5 in calculating the CO_2 and H_2 production rates.

[d] The non-hydrocarbons are assumed to contain 0.565 volume % CO_2 based on an average natural gas composition from Perry's Chemical Engineers Handbook.

Please note that if the feed is different from pipeline-quality natural gas, the emission factors for the simple approach will overestimate emissions due to the assumed higher carbon content of natural gas. In such an event, the stoichiometric conversion presented in Equation 6-48 should be used instead. This simple approach is demonstrated in Exhibit 6-44.

The simple approach is based on an emission factor of 32,721 pounds of carbon per million scf of feedstock (excluding H_2O) or 8,064 pounds of carbon per million scf of H_2 produced. These emission factors are shown in Table 6-51 below:

Table 6-51. Stoichiometric Conversion Emission Factor

CO_2 Emissions based on Feedstock Consumption	CO_2 Emissions based on Hydrogen Production
119,976 lb $CO_2/10^6$ scf feedstock	29,568 lb $CO_2/10^6$ scf H_2 produced
54.42 tonnes $CO_2/10^6$ scf feedstock	13.41 tonnes $CO_2/10^6$ scf H_2 produced
1,922 tonnes $CO_2/10^6$ m^3 feedstock	473.6 tonnes $CO_2/10^6$ m^3 H_2 produced

EXHIBIT 6-44: Sample Calculation for Hydrogen Plant Emissions - Simple Approach

INPUT DATA:
A hydrogen plant produces 13×10^9 scf of hydrogen per year. Calculate the CO_2 emissions.

CALCULATION METHODOLOGY:
CO_2 emissions are calculated using the emission factor derived from the average U.S. natural gas composition.

$$E_{CO_2} = 13{,}000 \frac{10^6 \text{ scf } H_2}{\text{year}} \times \frac{13.41 \text{ tonnes } CO_2}{10^6 \text{ scf } H_2}$$

$$\underline{E_{CO_2} = 174{,}300 \text{ tonne } CO_2/\text{yr}}$$

Although rare and not applicable to most refineries, a partial H_2 generation unit may be used (i.e., where only a portion of the H_2 available in the hydrocarbon stream is converted to H_2). If such a system is used, site-specific data or engineering judgment must be used to estimate the CO_2 emissions. If site-specific data are not available, one suggested estimation approach is to ratio the actual H_2 generation rate for the year to the design basis, and multiply this ratio by the design CO_2 emissions to estimate the actual CO_2 emission rate. Alternatively, a simplifying assumption would be to assume full conversion and use the simple emission factor or apply Equation 6-50, recognizing that this will overestimate emissions.

6.11.4 Asphalt Blowing

Asphalt blowing is used for polymerizing and stabilizing asphalt to increase its resistance to weathering for use in the roofing and shingling industries. This process involves contacting the asphalt oils with heated air. In addition to occurring at some refineries, asphalt blowing can also occur at asphalt processing and roofing plants. The exhaust air may be vented directly to the atmosphere, or the emissions may be controlled such as through vapor scrubbing or incineration (incineration would result in CO_2 emissions). Emissions of CO_2 and CH_4 from asphalt blowing are considered very small, because the majority of light hydrocarbons are removed during distillation (IPCC, 2006; EEA, 2007). However, emissions can be calculated using site-specific data or default emission factors.

The rigorous approach to estimating CH_4 emissions from asphalt blowing is based on using site-specific measured data. Thus, measurements of the exhaust gas flow rate and composition are needed for this estimation method. This approach is the same as the cold process vent approach to estimating emissions described later in this *Compendium* (refer to Section 6.11.5.2).

A simple emission factor for uncontrolled asphalt blowing is available from AP-42 (EPA, AP-42, Section 5.1.2.10, 1995). The AP-42 emission factor for asphalt blowing is assumed to be on an air-free basis (AP-42 does not specify this, but notes the factor represents "emissions"). A gas composition is needed to estimate the CH_4 emissions when using the simple emission factor approach. Site-specific measured data or engineering judgment may be used to estimate the exhaust gas concentrations. In the absence of such data, the CH_4 and CO_2 emission factors provided in Table 6-52 can be used:

Table 6-52. Default Asphalt Blowing Emission Factors

Emission Factor	Factor	Units
Total Emissions [a]	30	kg/Mg blown asphalt
	60	lb emissions/ton blown asphalt
	0.03 [b]	tonnes emissions/tonne blown asphalt
CH_4 [c]	5.55E-04	tonne CH_4/bbl asphalt blown
	3.49E-03	tonne CH_4/m^3 asphalt blown
	3.07E-03	tonne CH_4/ton asphalt blown
	3.38E-03	tonne CH_4/tonne asphalt blown
CO_2 [d]	1.01E-03	tonne CO_2/bbl asphalt blown
	6.38E-03	tonne CO_2/m^3 asphalt blown
	5.61E-03	tonne CO_2/ton asphalt blown
	6.19E-03	tonne CO_2/tonne asphalt blown

Footnotes and Sources:

[a] EPA, AP-42, Section 5.2.1.10, 1995

[b] Derived from AP-42 factor.

[c] Dimpfl, L.H. Study Gives Insight Into Asphalt Tank Explosions, "Oil and Gas Journal", December 1980. Derived using CH_4 composition (13% CH_4 on an air-free basis).

[d] Dimpfl, L.H. Study Gives Insight Into Asphalt Tank Explosions, "Oil and Gas Journal", December 1980. Derived using CO_2 composition (9% CO_2 on an air-free basis).

The emission factors above were derived from asphalt blowing exhaust composition data presented in an Oil & Gas Journal article (Dimpfl 1980)[12]. If site-specific exhaust stream data are available, emission factors should be derived in a similar fashion. The derivation of these factors is provided in Appendix B.

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[12] The same speciation, presented on an air-free basis is also reported in ARPEL, *Atmospheric Emissions Inventories Methodologies in the Petroleum Industry*, Table 6.24, 1998.

In the absence of site-specific data, controlled CH_4 and CO_2 emissions can be calculated using a mass balance approach, as shown in the following equations:

$$E_{CH_4} = \left(Q \times EF_{CH_4}\right) \times \left(1\text{-}DE\right) \qquad \textbf{(}\text{Equation 6-51}\textbf{)}$$

where:

E_{CH_4} = CH_4 emissions (metric tonnes/yr);
Q = Quantity of asphalt blown (bbl/yr or ton/yr);
EF_{CH_4} = CH_4 Emission factor from Table 6-52 (tonne/bbl or tonne/ton); and
DE = Control measure destruction efficiency (default DE = 98%, expressed as 0.98).

$$E_{CO_2} = \left(Q \times EF_{CO_2}\right) + \left(Q \times EF_{CH_4} \times DE \times \frac{44 \text{ mass units } CO_2/\text{mole}}{16 \text{ mass units } CH_4/\text{mole}}\right) \qquad \textbf{(}\text{Equation 6-52}\textbf{)}$$

where:

E_{CO_2} = CO_2 emissions (metric tonnes/yr);
Q = Quantity of asphalt blown (bbl/yr or ton/yr);
EF_{CO_2} = CO_2 Emission factor from Table 6-52 (tonne/bbl or tonne/ton);
EF_{CH_4} = CH_4 Emission factor from Table 6-52 (tonne/bbl or tonne/ton); and
DE = Control measure destruction efficiency (default DE = 98%, expressed as 0.98)/

Note that the second terms of Equation 6-51 and Equation 6-52 should only be used to calculate emissions from asphalt blowing when vented emissions are routed to a combustion control device. Also note that the first term in Equation 6-52 represents the vented CO_2 emissions while the second term reflects CO_2 emissions from combustion.

Exhibit 6-45 provides an example calculation for asphalt blowing emissions.

EXHIBIT 6-45: Sample Calculation for Asphalt Blowing Emissions

INPUT DATA:
Asphalt blowing occurs at a refinery. During the reporting year, 100,000 tons of asphalt are treated with air blowing. A site-specific exhaust stream composition profile is not available. The exhaust air is vented to the atmosphere uncontrolled. Calculate the CO_2 and CH_4 emissions.

CALCULATION METHODOLOGY:
CO_2 and CH_4 emissions are calculated by multiplying the annual blown asphalt rate by the CO_2 and CH_4 emission factors provided in Table 6-52.

$$E_{CO_2} = \frac{100{,}000 \text{ tons asphalt blown}}{\text{year}} \times \frac{5.61\text{E-03 tonne } CO_2}{\text{ton asphalt blown}}$$

$$\underline{E_{CO_2} = 561 \text{ tonnes } CO_2 \text{ emissions/yr}}$$

$$E_{CH_4} = \frac{100{,}000 \text{ tons asphalt blown}}{\text{year}} \times \frac{3.07\text{E-03 tonne } CH_4}{\text{ton asphalt blown}}$$

$$\underline{E_{CH_4} = 307 \text{ tonnes } CH_4 \text{ emissions/yr}}$$

6.11.5 Coke Calcining

Coke calcining operations, which convert green coke to almost pure carbon by heating the green coke and evaporating moisture and volatiles, may produce CO_2 emissions. CO_2 emissions should be calculated using engineering approaches such as material balances that incorporate site-specific values such as the CO_2 content of the exhaust gas as shown in Equation 6-53.

$$E_{CO_2} = \frac{44 \text{ mass units } CO_2\text{/mole}}{12 \text{ mass units C/mole}} \times (GC \times CC_{GC} - (PC_{out} + PC_{dust}) \times CC_{PC}) \qquad \text{(Equation 6-53)}$$

where:

E_{CO_2} = CO_2 emissions (metric tonnes/yr);
GC = Mass of green coke fed to the coke calcining unit from facility records (metric tons/year);
CC_{GC} = Average mass fraction carbon content of green coke from facility measurement data (metric ton carbon/metric ton green coke);
PC_{out} = Mass of marketable petroleum coke produced by the coke calcining unit from facility records (metric tons petroleum coke/year); and
PC_{dust} = Annual mass of petroleum coke dust removed from the process through the dust collection system of the coke calcining unit from facility records (metric ton petroleum coke dust/year). For coke calcining units that recycle the collected dust, the mass of coke dust removed from the process is the mass of coke dust collected less the mass of coke dust recycled to the process;
CC_{PC} = Average mass fraction carbon content of marketable petroleum coke produced by the coke calcining unit from facility measurement data (metric ton carbon/metric ton petroleum coke);
44 = Molecular weight of CO_2 (kg/kg-mole); and
12 = Atomic weight of C (kg/kg-mole).

6.11.6 Other Refining Related Venting Emissions

Other routine process vents in refineries include sources ranging from additional process units to crude oil storage tanks and loading operations. In general, the contribution to total CO_2 and CH_4 emissions from these other sources of process venting are relatively small in refining operations, due to low concentrations and/or routing the stream to the fuel gas system or flare.

- Thermal cracking processes produce CO_2 emissions, but as discussed under flexi-coking, would be considered under combustion emissions.
- Stabilized crude oil storage tanks in refineries vent small quantities of CH_4, depending on the partial pressure of CH_4 in the vapor space, tank dimensions and throughput, and controls. The methodologies for quantifying CH_4 emissions from stabilized crude storage tanks are covered in Section 6.10 for crude oil transport.
- Loading operations in refineries are also expected to vent minor quantities of CH_4, as well, and methodologies listed in Section 6.10 for crude oil transport would also apply for refinery operations.
- Compressor starts at refineries generally use compressed air. However, if refinery fuel gas is used to start compressor turbines, the emission factors presented for the production segment can be used to estimate CH_4 emissions, adjusting for the CH_4 composition in the fuel gas.
- For acid gas removal units located at a refinery, CO_2 emissions should be estimated using the site specific carbon content of the sour gas feed stream, as shown in Equation 6-54. All hydrocarbons in the sour gas stream feed stream to the acid gas removal unit contactor are assumed to be oxidized to CO_2. (Refer to Section 5 for estimation of carbon content of the feed stream from gas compositional analyses.) If site specific data is

unavailable, a simplified assumption of 0.20 mole C/mole gas[13] could be applied. Note that if the tail gas from the sulfur recovery plant is routed to a flare or incinerator, the emissions may be accounted for and care should be taken to avoid double counting.

$$E_{CO_2} = \left(F_{SG} \times \frac{44 \text{ mass units } CO_2/\text{mole}}{\text{molar volume conversion}} \times F_C\right) \qquad \text{(Equation 6-54)}$$

where:

E_{CO_2}	=	Emissions of CO_2 in units of mass (pounds, kg, tonnes) per year;
F_{SG}	=	Volumetric flow rate of sour gas (including sour water stripper gas) fed to the sulfur recovery unit in units of volume (scf, standard cubic meter) per year;
F_C	=	Mole fraction of carbon in the sour gas fed to the sulfur recovery unit (mole C/mole gas), if unknown, assume default = 0.20; and
Molar volume conversion	=	Conversion from molar volume to mass (379.3 scf/lbmole or 23.685 Sm^3/kgmole).

Non-routine activities in refineries include equipment or process blowdowns, heater or boiler tube decoking, pressure relief valves, or emergency shut downs. Gas releases from these sources are generally routed to the fuel gas system or to a flare, in which case emissions from these sources would be included with the combustion source emission estimates (refer to Sections 4 and 5).

If process blowdowns occur that vent to the atmosphere, CH_4 emissions can be estimated using similar estimation methodologies included for the gathering and boosting segment, adjusting for the CH_4 composition in the fuel gas (refer to Section 6.4), or by using a simplified emission factor of 137,000 scf CH_4/million barrel of crude oil plus the quantity of intermediate products received from off-site that are processed at the facility[14].

Similar to associated gas venting, "cold" process vents refer to the vented release of emissions without combustion. While most process vents in a refinery are typically recovered to a fuel gas system or flare, there could be a vent stream that has unaccounted for venting that could result in CH_4 or CO_2 emissions (e.g. venting may occur through an unlit flare tip). The calculation methodologies outlined in Section 6.3.1 for associated gas venting should be used to estimate emissions from cold vents at a refinery.

Emissions from any other refinery process vents not addressed in the API Compendium should be estimated using an engineering approach.

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[13] This factor is from EPA's GHG Reporting Program (40 CFR Part 98, Subpart Y).

[14] This factor is from EPA's GHG Reporting Program (40 CFR Part 98, Subpart Y).

6.12 Petrochemical Manufacturing

The petrochemical industry consists of numerous processes that use fossil fuel or petroleum refinery products as feedstocks. During the petrochemical production processes, GHG emissions can be released to the atmosphere depending on the design of the system. Per IPCC guidance, there are six processes that have been recognized to have more significant CH_4 emissions compared to other petrochemical processes:

- Acrylonitrile - (vinyl cyanide, C_3H_3N) is made by way of direct ammoxidation of propylene with ammonia (NH_3) and oxygen over a catalyst. The process also produces by-products including CO_2 and CO, which are routed with the off gas stream to a flare or oxidizer.
- Carbon black – made from the incomplete combustion of an aromatic petroleum or coal-based feedstock. It is most commonly added to rubber to improve strength and abrasion resistance, and the tire industry is the largest consumer. The carbon black process results in CO_2 and other hydrocarbons in the tail gas stream, which may be combusted for energy recovery, flared, or vented to the atmosphere.
- Ethylene – used in the production of plastics such as polymers. Most ethylene is produced by steam cracking of hydrocarbon feedstock, leading to CO_2 emissions from the combustion units and small amounts of vented CH_4.
- Ethylene dichloride – an important intermediate in the synthesis of chlorinated hydrocarbons. It is also used as an industrial solvent and fuel additive. In addition to the byproduct CO_2 produced from the direction oxidation of the ethylene feedstock, CO_2 and CH_4 emissions are also generated from combustion units.
- Ethylene Oxide - used in the manufacture of glycols, glycol ethers, alcohols, and amines. Ethylene oxide is manufactured by the catalytic reaction of ethylene with oxygen. CO_2, a by-product of the oxidation reaction, is removed and may be vented to the atmosphere or recovered.
- Methanol – an alternative transportation fuel as well as a principal ingredient in paints, solvents, refrigerants, and disinfectants. Methanol-based acetic acid is used in making certain plastics and polyester fibers. Methanol is most commonly manufactured from synthesis gas using steam CH_4 reforming (refer to Section 6.11).

While these processes have the potential to result in vented CH_4 and/or CO_2, many of the streams containing these GHGs may be routed to furnaces, fuel gas systems, flares, or other control devices and accounted for in other source streams. Care should be taken to avoid double counting the emissions, if included as combustion emissions from other sources.

The petrochemical processes listed above are not intended to represent the entire petrochemical process industry. There are a number of other petrochemical processes that may emit small amounts of greenhouse gases for which specific guidance is not provided here but should be accounted for in specific inventories, as applicable (e.g., styrene production).

Emissions of CO_2 can be estimated using a material balance approach that calculates the difference in the amount of carbon entering the process as feedstock and the amount of carbon exiting the production process as a petrochemical product or by-product as shown in Equation 6-55. Note that this equation does not account for the GHG emissions associated with combustion of fuel to provide heat to the process; combustion emissions are addressed in Section 4. As previously stated, it is important to consider whether the CO_2 in the process off gas stream is accounted for in other combustion systems, such as flares, oxidizers, or fuel gas systems, to avoid double counting emissions.

$$ECO_{2i} = \left\{\sum_k\left(FS_{i,k} \times C_{FSk}\right) - \left[PP_i \times CP_i + \sum_j\left(SP_{i,j} \times SC_j\right)\right]\right\} \times \frac{44}{12} \qquad \text{(Equation 6-55)}$$

where:

ECO_{2i} = CO_2 emissions from production of petrochemical *i*, tonnes;
$FS_{i,k}$ = Annual consumption of feedstock *k* for production of petrochemical *i*, tonnes;
C_{FSk} = Carbon content of feedstock *k*, tonnes C/tonne feedstock;
Ppi = Annual production of primary petrochemical product *i*, tonnes;
C_{Pi} = Carbon content of primary petrochemical product *i*, tonnes C/tonne product;
$SP_{i,j}$ = Annual amount of secondary product *j* produced from production process for petrochemical *i*, tonnes (if applicable); and
SC_j = Carbon content of secondary product *j*, tonnes C/tonne product.

Additionally, nitrous oxide (N_2O) emissions result from two additional chemical processes:

- Adipic acid - Adipic acid is a dicarboxylic acid manufactured from a cyclohexanone/cyclohexanol mixture that is oxidized. Nitrous oxide is generated as an unintended by-product of the nitric acid oxidation stage. It is used in the manufacture of synthetic fibers, coatings, plastics, urethane foams, elastomers, and synthetic lubricants. Food-grade adipic acid is used as a flavor additive.
- Nitric acid production - Nitrous oxide is generated as a by-product of nitric acid oxidation in the second stage of a two-stage production process. Nitric acid (HNO_3) is an inorganic compound used primarily to make synthetic commercial fertilizers. It is typically produced by the catalytic oxidation of ammonia, where N_2O is formed as a by-product.

In the absence of site-specific data, GHG emissions could be calculated through the use of default emission factors, which are based on EPA's annual national GHG inventory (EPA, 2019b) and/or the Intergovernmental Panel on Climate Change (IPCC, 2019[15]). Table 6-53 provides average

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[15] Note that the 2019 refinement of the IPCC 2006 guidelines indicate that no changes were made from the 2006 IPCC version of the methods and emission factors for the petrochemical processes.

emission factors for each of the petrochemical processes described above based on the production rate (EPA, 2019b). The CO_2 and CH_4 emission factors are based on material balances of the petrochemical processes. As previously stated, care should be taken to avoid double counting CO_2 emissions from process venting with combustion emission sources. The N_2O emission factors account for the use of N_2O abatement technologies, such as non-selective catalytic reduction (NSCR) and are derived from IPCC 2006, Volume 3. Emissions are estimated by multiplying the chemical production rate by the appropriate emission factor based on the process type, and for N_2O, the abatement method.

Table 6-53. Chemical Production Emission Factors

Chemical Production Process	Emission Factor, Original units	Emission Factor, Converted Units
CH_4 Emission Factors		
Acrylonitrile[a]	0.18 kg CH_4/tonne produced	0.00018 tonne CH_4/tonne produced
Carbon Black[b]		
- without abatement	28.7 kg CH_4/tonne produced	0.0287 tonne CH_4/tonne produced
- with thermal abatement	0.06 kg CH_4/tonne produced	0.00006 tonne CH_4/tonne produced
Ethylene[b]		
- ethane feedstock	6 kg CH_4/tonne produced	0.006 tonne CH_4/tonne produced
- all other feedstocks (other than ethane)	3 kg CH_4/tonne produced	0.003 tonne CH_4/tonne produced
Ethylene Oxide[b]		
- without abatement	1.79 kg CH_4/tonne produced	0.00179 tonne CH_4/tonne produced
- with thermal abatement	0.79 kg CH_4/tonne produced	0.00079 tonne CH_4/tonne produced
Methanol[a]	2.3 kg CH_4/tonne produced	0.0023 tonne CH_4/tonne produced
N_2O Emission Factors		
Nitric acid[b]		
- with NSCR	2 kg N_2O/tonne produced	0.002 tonne N_2O/tonne produced
- without NSCR[c]	9 kg N_2O/tonne produced	0.009 tonne N_2O/tonne produced
Adipic acid[b]		
- with catalyic abatement[d]	0.053 kg N_2O/kg produced	0.053 tonne N_2O/tonne produced
- with thermal abatement[e]	0.013 kg N_2O/kg produced	0.013 tonne N_2O/tonne produced
- without abatement	0.3 kg N_2O/kg produced	0.3 tonne N_2O/tonne produced
CO_2 Emission Factors		

Chemical Production Process	Emission Factor, Original units	Emission Factor, Converted Units
Acrylonitrile[a]	1.00 tonne CO_2/tonne produced	1.00 tonne CO_2/tonne produced
Carbon Black[a]	2.63 tonne CO_2/tonne produced	2.63 tonne CO_2/tonne produced
Ethylene[a]	0.77 tonne CO_2/tonne produced	0.77 tonne CO_2/tonne produced
Ethylene Dicloride[a]	0.041 tonne CO_2/tonne produced	0.041 tonne CO_2/tonne produced
Ethylene Oxide[a]	0.46 tonne CO_2/tonne produced	0.46 tonne CO_2/tonne produced
Methanol[a]	0.67 tonne CO_2/tonne produced	0.67 tonne CO_2/tonne produced

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (EPA). Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2017, April 2019, pg 4-54. These values are country-specific and based on US operations.

[b] Intergovernmental Panel on Climate Change. 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 3: Industrial Processes and Product Use. Chapter 3: Chemical Industry Emissions. Prepared by the National Greenhouse Gas Inventories Programme. Eggleston, H.S., Buendia L., Miwa K., Ngara T. and Tanabe K. (eds).Published: IGES, Japan. 2006.

[c] Note that selective catalytic reduction (SCR) and extended absorption are not known to reduce N_2O emissions.

[d] Catalytic abatement is assumed to have a destruction efficiency of 92.5% of N_2O and a utility factor of 89% (IPCC 2006).

[e] Thermal abatement is assumed to have a destruction efficiency of 98.5% of N_2O and a utility factor of 97% (EPA 2009).

6.13 Retail and Marketing of Petroleum Liquids

The retail and marketing segment includes company-owned retail operations and support to customer fueling operations. Venting of GHG emissions from the retail and marketing of petroleum liquids is considered negligible, because of insignificant concentrations of CH_4 and CO_2 in the fuel products.

6.14 Fire Suppression Emissions

The use of fire suppression equipment may result in emissions of high global warming potential (GWP) greenhouse gases (GHGs) as a result of using them as substitutes for ozone-depleting substances (ODSs). The GHGs of concern from such fire suppression equipment are typically hydrofluorocarbons (HFCs) or perfluorocarbons (PFCs). The global warming potentials for such HFCs and PFCs are typically several thousand times larger than for carbon dioxide (CO_2). Carbon dioxide may also be used as a fire suppressant.

Emissions from the diversity of fuel burned during fires should be calculated using the methodology described in Section 4: Combustion Emissions.

To estimate fire extinguisher emissions, a material balance approach, such as provided by Equation 6-56 (EPA, 2012), should be used. The material balance should consider the amount of fire suppressant released in each event, the number of events annually, and the composition of the particular GHG in the fire suppressant.

$$E_j = r \times \sum_{i=1}^{k} Q_{C_{j+1}} \qquad \text{(Equation 6-56)}$$

where:

E_j = total emissions of chemical released in year j, by weight;
r = percentage of total chemical in operation released to the atmosphere;
Q_C = quantity of chemical used in new fire extinguishing equipment one lifetime (k) ago (e.g., j – k +1), by weight;
i = counter, from 1 to lifetime (k);
j = year of emissions; and
k = average lifetime of the equipment.

6.15 References

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Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Natural Gas and Oil Industry

Section 7 – Fugitive Emissions Estimation Methods

November 2021

Table of Contents

List of Tables

List of Figures

7.0 EQUIPMENT LEAKS EMISSION ESTIMATION METHODS

7.1 Methodology Overview

For the purposes of this document, fugitive emissions refer to the unintentional release of emissions from sources that can include equipment leaks or non-point evaporative sources, such as wastewater treatment systems, pits, impoundments, and mine tailing ponds. It is important to note that the boundary around what constitutes fugitive emissions may differ depending on the reference used. For example, the Intergovernmental Panel on Climate Change (IPCC) refers to fugitive emissions as all non-combustion sources of emissions1. This Compendium document distinguishes vented emissions separately from fugitive emissions.

Emissions from equipment leaks are discussed in Sections 7.2 through 7.4, while emissions from other fugitive sources and fluorinated gases are discussed in Sections 7.5 and 7.6, respectively.

Equipment leaks are a category of fugitive emissions that refers to unintentional emissions from leaking pressurized equipment. Any pressurized equipment has the potential to leak; these leaks generally occur through valves, flanges, seals, or related equipment associated with “live” crude or gas system components.

Fugitive emissions are also associated with non-point evaporative sources, such as from wastewater treatment, pits, impoundments, and mine tailing pond surface emissions as well as unintentional losses from electrical transformers and refrigeration systems. This section presents methods for estimating CH4 and potentially CO2 emissions from these fugitive sources, as well as estimation methods for perfluorocarbons (PFCs), hydrofluorocarbons (HFCs), and sulfur hexafluoride (SF6) emissions. Table 7-1 illustrates the range of available options for estimating fugitive GHG emissions from equipment leaks and associated considerations.

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[1] IPCC defines fugitives for oil and gas operations as: “In general, fugitive emissions from oil and gas activities may be attributed to the following primary types of sources: fugitive equipment leaks; process venting; evaporation losses; disposal of waste gas streams (e.g., by venting or flaring), and accidents and equipment failures.” Reference: IPCC, *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories*, Chapter 2, Section 2.7, May 2000.

Table 7-1. Emission Estimation Approaches – GHG and Source-Specific Considerations for Fugitive Sources

Types of Approaches	CH_4 Non-combustion Emissions	CO_2 Emissions	PFC, HFC, SF_6 Emissions
Published emission factors	• Based on facility type or "average" equipment and emission source characteristics • Relies on population based updates over time to remain reliable.	• Limited emission factors specific to non-combustion CO_2 emissions. • May be scaled from CH_4 emission factors	• Simplified estimations based on average equipment and emission source characteristics are aligned with low contribution to overall emissions
Engineering calculations	• Highly reliable for specific emission sources • May require detailed input data	• Highly reliable for many emission sources • May require detailed input data	• Material balance methods provide good reliability • Requires data tracking
Monitoring over a range of conditions and deriving emission factors	• Highly reliable for specific emission sources • Generally not practical given the substantial number and variety of emission sources	• Generally not practical given the low contribution to overall emissions	• Generally not practical given the low contribution to overall emissions
Periodic or continuous monitoring of emissions or parameters for calculating emissions	• Highly reliable for specific emission sources • Generally not practical given the substantial number and variety of emission sources	• Not practical given the number and variety of emission sources and the low contribution to overall emissions	• Not practical given the number and variety of emission sources and the low contribution to overall emissions

A variety of fugitive emission sources are related to oil and gas industry operations. The type of fugitive emissions discussed in this subsection are equipment leaks from valves, flanges, pump seals, compressor seals, relief valves, sampling connections, process drains, open-ended lines, and other miscellaneous component types. There have been numerous documents and several recent studies published outlining the estimation of fugitive CH_4 emissions from equipment leaks, based on the increased focus on accurately quantifying, and ultimately reducing, CH_4 emissions. In comparison, data on fugitive equipment leak emissions of CO_2 are not generally presented because

CO_2 emissions are more commonly associated with combustion sources. It may be possible to adapt the estimation methods presented for CH_4 to the oil and gas operations for which CO_2 equipment leaks might be of significance, such as with equipment from a CO_2-enhanced oil production field. This is addressed further as related to specific emission sources.

A number of emission factors and correlation equations have been developed for estimating fugitive equipment leak emissions for VOC and TOC, for example, based on US EPA Method 21 (EPA, 2017). Many of these approaches require monitoring data and calculations at the component-level. The approaches available for quantifying most GHG fugitive equipment leak emissions are listed below, in order of increasing data requirements and generally increasing accuracy:

1. Facility-level average emission factors;
2. Equipment-level average emission factors;
3. Component-level average emission factors; and
4. Component-level monitoring or measurement approaches.

When estimating the fugitive equipment leak contribution to a GHG inventory, the method that meets the inventory accuracy needs and for which data are available should be used. Figure 7-1 presents the available options for consideration based on the overall contribution of the fugitive emissions to the entity's inventory or the availability of information from a component count program [e.g., leak detection and repair (LDAR)]. However, **methodologies required by local regulations take precedence over the options provided in the decision trees.**

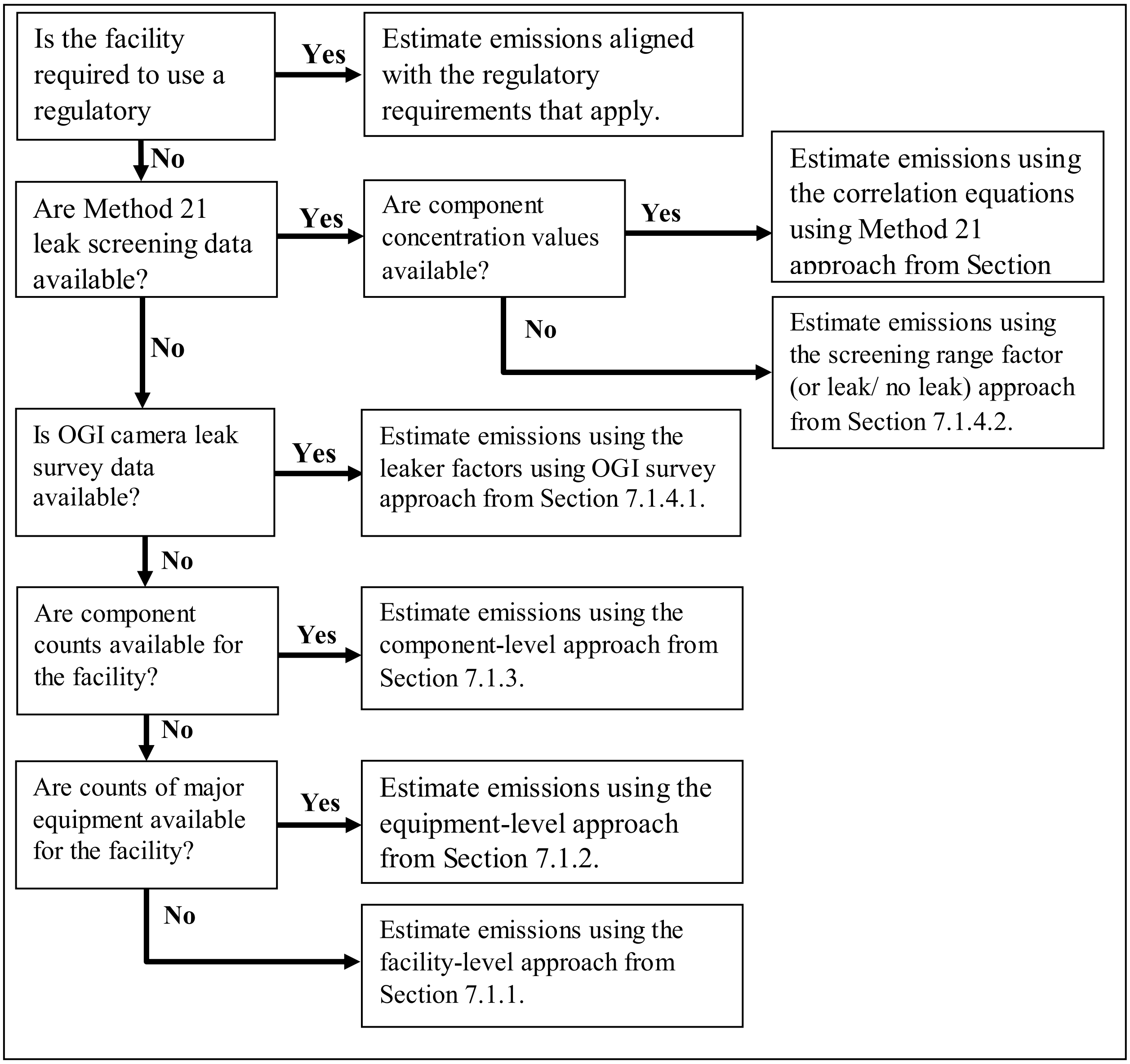

Figure 7-1. Emission Estimation Approaches for Fugitive Equipment Leaks

The contribution of fugitive equipment leak emissions to an overall facility’s GHG inventory varies with the type of facility. For example, fugitive CH_4 emissions from equipment leaks at a gas processing facility could be a significant element of the total GHG inventory, so the accuracy of the fugitive emissions estimates could be a determining factor in the overall facility inventory. Conversely, refinery fugitive equipment leak emissions will generally have an insignificant contribution to the total refinery GHG inventory because most refinery streams contain only small amounts of CH_4 (refer to Appendix D for more information). Using a less detailed estimation method for refinery fugitive emissions would generally be acceptable because the contribution of fugitive equipment leak emissions would have very little influence on the overall refinery inventory accuracy.

The selection of a fugitive equipment leak estimation approach must also consider the data available to support the estimate. Most fugitive equipment leak emission estimation methods require site-specific gas composition to convert from a TOC, VOC, or default CH_4 concentration basis. The facility-level average emission factor approach (Section 7.1.1) requires only identifying the type of facility and knowing its capacity. General major equipment counts are required for the approach described in Section 7.1.2. Both facility-level and equipment-level approaches can be utilized in the absence of component count data. Conversely, component-level average emission factor approaches (Sections 7.1.3 and 7.1.4) require detailed count of components (such as valves, connections, pump seals, etc.), and for some emissions factors, these component counts will have to be categorized by service type (such as for valves in gas, light liquid, or heavy liquid service). Some of the more rigorous component-level measurement approaches (detailed in Section 7.1.4) require monitoring data in addition to component counts.

Ultimately, accuracy must be balanced against the available data. If the available data will not support an estimate of the needed accuracy, additional data gathering may be required. A balance needs to be maintained between the gains in accuracy and the cost of additional data gathering. Methodologies selected need to be consistent with the contribution of particular sources to the overall inventory.

7.1.1 Facility-Level Average Emission Factor Approach

The level of data available is critical in determining the best emission estimation approach to utilize. Facility-level approaches can be used when component count data and even major equipment counts are unavailable. It should be noted that the facility-level approach is the least accurate method for quantifying fugitive GHG emissions from equipment leaks.

Applying average facility-level emission factors is the simplest method for estimating CH_4 fugitive emissions from oil and gas operations. The user simply needs to know the type of facility and its throughput to use these factors, such as onshore gas production in million standard cubic feet per day (scfd). These facility-level factors were developed by aggregating component emission measurements and activity factors for a “typical” facility, primarily for upstream gas industry facilities. Facility-level emission factors for upstream, midstream, and downstream operations are presented in Sections 7.2, 7.3, and 7.4, respectively.

7.1.2 Equipment-Level Average Emission Factor Approach

The equipment-level average emission factor approach allows the fugitive equipment leak emission estimates to be tailored to a particular facility based on the population of major equipment at the facility, which can be used to model the number of components when component count data is not available. This approach requires more information than the facility-level approach, but results in a slightly more accurate emission estimate than the facility-level approach. It is especially useful when trying to estimate GHG emissions for a planned facility that has not yet been fully designed or for an existing facility where no detailed minor component count data are available.

Fugitive emission factors for production equipment, processing equipment, transmission and storage equipment, as well as distribution equipment and stations, are provided in the relevant Sections 7.2, 7.3, and 7.4. The emission factors were developed from extensive component monitoring and emission measurement data. The minor component emission factor data were then aggregated using activity factors that characterized the number of each minor component per major equipment system. This approach of aggregating individual components into major equipment systems may be appropriate for some GHG emission calculation efforts, where component count data is unavailable.

7.1.3 Component-Level Average Emission Factor Approach

When data on the counts of each component-type are available for a facility, but leak monitoring data are not, an approach using component-level average emission factors can be used. When using the component-level average emission factor approach, site-specific data should be used for the component counts. This approach provides a more accurate estimation than equipment- or facility-level emission factors, since it is based on site-specific component count data.

If site-specific counts are not available, then component counts may be estimated based on counts for similar facilities within the organization, when using the component-level average emission factor approach. In the absence of component counts from other similar facilities within the organization, "generic" component counts can be utilized as detailed in Appendix C, Section C.1.1.

The component-level average emission factor approach is based on the number of components, categorized as valves, flanges, pump seals, compressor seals, relief valves, sampling connections, process drains, open-ended lines, and other miscellaneous types, in the facility. The emission factors were developed from extensive component monitoring and emission measurement data, and may be further subdivided by stream service type (e.g., gas, light liquid, heavy liquid) or other factors.

Average emission factors at the component-level for oil and gas production facilities are provided in Section 7.2. Average component-level emission factors for midstream and downstream operations are included in Section 7.3 and 7.4, respectively.

7.1.4 Component-Level Monitoring or Measurement Approaches

The component-level monitoring or measurement approaches are based on the number of components in the facility along with additional information. This measurement approach is the most rigorous with regards to data requirements and also provides the highest level of accuracy of the methods presented in this document. For this approach, monitoring data from US EPA Method 21 or Optical Gas Imaging (OGI) can be utilized. Additionally, Hi-Flow monitors can be utilized to determine actual mass emission rates.

This section provides an overview of estimation methods for CH_4 and CO_2 fugitive emissions from equipment leaks that are more rigorous than the methods presented in Sections 7.1.1 through 7.1.3. The measurement-based approaches available for estimating fugitive equipment leak emissions, in order of increasing data requirements and potentially increasing accuracy are:

1. Leaker Factors using leak screening surveys;
2. Screening Range Factors;
3. Correlation Equations Using Method 21 Monitoring; and
4. Unit-Specific correlation approach.

For all of these approaches, the CH_4 composition of the fugitive stream and the population of fugitive components, or number of leaking components, must be known. When site specific speciation data are not available, "generic" compositions may be utilized for estimating CH_4 emissions from fugitive sources. These "generic" compositions are further detailed in Appendix C, Section C.1.1.

7.1.4.1 Leaker Factors Using Leak Screening Surveys

Existing regulations require, or allow, the use of optical gas imaging (OGI) cameras to identify leaking components, as an alternative to U.S. EPA Method 21. This method of detecting leaks differs from Reference Method 21, which requires screening at the interface of each individual component. Optical gas imaging does not provide screening values (or concentration associated with the leaking component, in ppmv), but it does allow the facility to identify which components are leaking (also called "leakers"). In cases where optical gas imaging is utilized, total component count data may not be available since only the "leakers" are used in the emission estimation.

The "leaker" emission factor approach can be utilized when optical gas imaging is used and the total number of leaking components is available. The leaker emission factor approach can also be used with data generated using other leak detection methods, such as the use of flame ionization detectors (FIDs) as used in methods such as EPA Method 21, for leaks over a defined leak screening threshold. In the leaker emission factor approach, total fugitive emissions for a facility are quantified using the number of leaking components and associated leaker emission factors. Emission factors utilizing this approach have been published in EPA's GHGRP Subpart W, as well as other published studies presented in Sections 7.2 through 7.4.

7.1.4.2 Screening Range Factor Approach

The screening range factor approach, also called the leak/no-leak approach, is based on monitoring data that have been categorized into two or more ranges. Monitoring data are broken into categories of "leakers", which in general, are those components with leak screening readings greater than or equal to a specified threshold. For example, certain EPA methodologies utilize 10,000 ppmv[2] and others 500 ppmv, and "non-leakers" with readings less than the threshold value. The leakers over the threshold level, are assigned an emission factor and those below the leaker threshold level are assigned a non-leaker emission factor. The specific "leaker" threshold relevant to each published study is further detailed in Sections 7.2, 7.3, and 7.4.

This threshold criterion for separating leakers from non-leakers may not coincide with the leak definition required by local regulations that apply to each facility, but it is the only level for which there is any significant amount of mass emission data to develop screening range factors. The screening range approach should be more accurate than previously presented approaches because it is based on a site-specific percent "leaking" measurement. This approach could be appropriate for facilities that are already collecting monitoring data for their LDAR program, or would be willing to do so to improve their emission estimates.

When using the screening range factor approach, the components should be grouped into "streams" where all the components have approximately the same TOC weight fraction and monitoring readings within the same category.

7.1.4.3 Correlation Equations Using Method 21 Monitoring

The correlation approach predicts the mass emission rate as a function of the screening value for a particular equipment type. The screening values for the correlation approach are concentration

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[2] The 10,000 ppmv break point is based on early leak definitions, such as in 40 CFR 60 Subpart VV.

measurements obtained during monitoring using US EPA Method 21 for each individual component. This method can be utilized when Reference Method 21 is used and screening values (or monitored concentrations, in units of ppmv) are available for each component.

The screening value to leak rate correlations were developed based on data collected from petroleum industry units, including refineries, and oil and gas production operations. The key difference between this approach and those previously discussed is that the user must estimate the emission rate for each component individually, rather than in large groups by component and service type. This method is generally only practical when the site maintains a specialized database that records LDAR monitoring activities and calculates the emission rates, although a facility with few components could use a spreadsheet to estimate emissions by the correlation approach. The specialized databases are common in refineries, but less common in other oil and gas industry facilities. While refineries have the database to support emission estimating by correlations, the CH4 composition of refinery fugitive equipment leak emissions is generally negligible (with the exception of the natural gas system, which is not commonly covered by the LDAR database). If monitoring data and the means to make the correlation calculations on an individual component basis are available, the correlation approach can provide accurate estimates of equipment leak emissions.

The correlation approach uses measured concentration levels for all components screened, with the exception of those components that were either below the lower limit of detection of the analyzer (often called “default zero”) or above the upper limit of detection (often called “pegged”). Default zero and pegged emission factors are used for these types of readings as an adjunct to the correlation equations.

7.1.4.4 Unit-Specific Correlation Approach

The previous subsection described the use of leak rate and screening value correlations using methodologies that have been published for general petroleum industry use. It is also possible to develop unit-specific and/or site-specific correlations that can be used in the same manner. Developing unit-specific correlations requires the collection of screening values and measured mass emissions for a subset of components from the subject process unit. These data must then be statistically analyzed to develop the correlation equations. An in-depth description of the Unit-Specific Correlation Approach may be found in the EPA Protocol for Equipment Leak Emission Estimates, Section 2.3.4 (EPA 1995). This approach can be quite expensive. An existing unit-specific correlation (if available) may be used for the subject process, but it would seldom be justified to try to develop unit-specific correlations to support GHG emission estimates.

7.1.5 Time Basis of Equipment Leaks

All of the fugitive approaches presented in this section result in estimates of the equipment leak rate over a short time period, such as an hour or a day. Those estimates are multiplied by the number of hours (or days) of annual operation to result in the annual emission estimate. The components subject to fugitive equipment leaks have the potential to leak any time the line is filled with hydrocarbons, even if not under normal pressure or if the component is idle (such as a pump). For this reason, most equipment leaks are calculated as if they emitted continuously for the full year, or 8,760 hours per year. If a facility shuts down and depressurizes equipment for maintenance for a portion of the year, that time can be deducted from the annual operating hours. Depressurized equipment that is free of hydrocarbons (e.g. purged with air) would also not have fugitive emissions; that time can be deducted from the annual operating hours as well.

If the facility conducts routine (periodic) monitoring or monitors components following leak repair, the facility may utilize the date the leak was found and the date of repair to determine the number of hours for each applicable emission factor. For example, if the facility is using the Screening Range Factor approach and observed a component to be leaking but immediately repaired the leak and confirmed via U.S. EPA Method 21 monitoring, or other equivalent methods, then the leaker emission factor should be assumed only for a portion of the 8,760 hours per year. Since it is unknown when the leak occurred, simplifying assumptions can be used to account for the duration of the leaking component. If prior monitoring data are available, emissions can be estimated by assuming that the leaker emission factor is multiplied by half of the operating hours of a piece of equipment between the previous leak survey (in which the component was found not leaking) and the time when the leak was found and repaired (CCAC, 2017).

7.2 Equipment Leaks Estimation – Upstream Operations

In upstream operations, fugitive emissions from equipment leaks can occur from valves, flanges, seals, or related equipment associated with petroleum and natural gas system components. This section provides further details on the various methodologies, or approaches, as well as emission factors for calculating equipment leak emissions from the following operations:

- Offshore oil and gas exploration and production;
- Onshore oil and gas exploration and production; and

- Gathering and boosting operations.

A summary of all the emission factor sets included for upstream oil and gas operations is provided in Table 7-2. As shown, the emission factor sets are organized by the type of operation and the equipment leak approach. This summary is intended to help guide the user in selection of the most appropriate emission factors for quantification of equipment leak emissions from upstream operations. The application of specific sets of emission factors will depend on the type of operation and the data available for quantifying equipment leak emissions. For example, emission factors derived from studies using an OGI camera for leak monitoring that have been obtained from onshore production operations are not included for either offshore or gathering and boosting operations.

7.2.1 Offshore Oil and Gas Exploration and Production

7.2.1.1 Facility Level

As detailed in Section 7.1.1, applying average facility-level emission factors is the simplest method for estimating CH_4 emissions from oil and gas operations. Fugitive emissions from equipment leaks can be calculated using the facility-level approach when only the type of facility and throughput are known. Facility-level emission factors for offshore oil and gas exploration and production are presented in Table 7-3.

Table 7-3 provides separate fugitive emission factors from equipment leaks for oil and gas production operations. However, oil and gas can be produced from the same well. For facilities that produce any natural gas or are equipped similarly to the gas well schematic shown in Figure 7-2, the gas production emission factors should be used. For facilities that do not market the associated gas, or produce only crude or are equipped similar to the oil well schematic shown in Figure 7-2, the oil production emission factors should be used.

The level of accuracy may not be sufficient for many facilities considering the increased focus on methane emissions. If the facility is atypical of the industry average or greater accuracy is needed to support emission reduction estimates, one of the more rigorous approaches should be used.

Table 7-2. Equipment Leaks Emission Factor Summary Table – Upstream Operations

Table Number	Table Title	Data Source(s)	Location	Year Published	Measurement Approach	Sample Size	Original Data Source
Section 7.2.1.1 Offshore Oil and Gas Exploration and Production – Facility Level							
7-3	Facility-Level Average Equipment Leak Emission Factors for Offshore Production	This table assumes offshore emission factors based on a percentage of onshore emission factors, listed in Table 7.2-6. See Table 7.2-6 for references.					
7.2.1.3 Offshore Oil and Gas Exploration and Production – Component Level Average Emission Factor							
7-4	API Average Offshore Equipment Leak Emission Factors	American Petroleum Institute (API). Emission Factors for Oil and Gas Production Operations, API Publication No. 4615, January 1995	US	1995	Document not publically available without purchase. Data source referenced in USEPA GHGRP Regulatory Program.		
7-5	Offshore THC Equipment Leak Emission Factors	Norwegian Environment Agency. *Cold Venting and Fugitive Emissions from Norwegian Offshore Oil and Gas Activities: Module 2 - Emission Estimates and Quantification Methods*, Sub-report 2, 15 March 2016, Table 49.	Norway	2016			
7-6	Generic Offshore THC Equipment Leak Emission Factors	Norwegian Environment Agency. *Cold Venting and Fugitive Emissions from Norwegian Offshore Oil and Gas Activities: Module 2 - Emission Estimates and Quantification Methods*, Sub-report 2, 15 March 2016, Table 52.	Norway	2016			

Table Number	Table Title	Data Source(s)	Location	Year Published	Measurement Approach	Sample Size	Original Data Source
7.2.1.5 Offshore Oil and Gas Exploration and Production – Screening Range Factors							
7-7	API Oil and Gas Offshore Screening Emission Factors	American Petroleum Institute (API). Emission Factors for Oil and Gas Production Operations, API Publication No. 4615, January 1995, Table ES-2	US	1995	Document not publically available without purchase. Data source referenced in USEPA GHGRP Regulatory Program.		
7.2.2.1 Onshore Oil and Gas Exploration and Production – Facility Level							
7-8	Facility-Level Average Equipment Leak Emission Factors for Onshore Production	Harrison, et al. Methane Emissions from the U.S. Petroleum Industry, Final Report, EPA-600/R-99-010. U.S. Environmental Protection Agency	US	1999	Derived	Derived	API. Emission Factors for Oil and Gas Production Operations, API Publication No. 4615. Published in 1995.
		Campbell, et al. 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	US	1996	GRI High Flow or EPA Protocol Method 21	For onshore production in Eastern U.S., 192 individual well sites at 12 eastern gas production facilities. For onshore production in the Western U.S., 83 gas wells at 4 gas production sites.	Direct measurement study conducted in the early 1990s and published in 1996.
		Hummel, et al. Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Final Report, GRI-94/0257.25 and EPA-600/R-96-080h. Gas Research Institute and U.S. Environmental Protection Agency	US	1996	GRI High Flow or EPA Protocol Method 21		Direct measurement study conducted in the early 1990s and published in 1996. Data source referenced in USEPA GHGRP Regulatory Program.
		DOE, Petroleum Supply Annual	US	1993	Not applicable	Not applicable	Not applicable

Table Number	Table Title	Data Source(s)	Location	Year Published	Measurement Approach	Sample Size	Original Data Source
		DOE, Natural Gas Annual	US	1995	Not applicable	Not applicable	Not applicable
7.2.2.2 Onshore Oil and Gas Exploration and Production – Equipment Level							
7-9	Equipment Leak Emission Factors for Onshore Crude Production Equipment	Harrison, M.R., T.M. Shires, R.A. Baker, and C.J. Loughran. Methane Emissions from the U.S. Petroleum Industry, Final Report, EPA 600/R-99-010, U.S. Environmental Protection Agency, 1999	US	1999	Derived	Derived	API. Emission Factors for Oil and Gas Production Operations, API Publication No. 4615. Published in 1995.
		Tilkicioglu, B.H and D.R. Winters. Annual Methane Emission Estimate of the Natural Gas and Petroleum Systems in the United States. Pipeline Systems Incorporated (PSI), December 1989	US	1989	Document not publically available without purchase.		
7-10	Equipment Leak Emission Factors for Onshore Natural Gas Production Equipment	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	US	1996	High flow analyzer or bagging technique.	For onshore production in Eastern U.S., 192 individual well sites at 12 eastern gas production facilities. For onshore production in the Western U.S., 83 gas wells at 4 gas production sites.	Direct measurement study conducted in the early 1990s and published in 1996.

Table Number	Table Title	Data Source(s)	Location	Year Published	Measurement Approach	Sample Size	Original Data Source
		Campbell, L.M., et al. Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines, Final Report, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996	US	1996	FID to identify leak, laminar flow element (LFE) to estimate leaks below 450 scfh, and dry gas meter for leaks above 450 scfh	146 leak tests performed by participating companies out of target sample size of 200 tests	Direct measurement study conducted in the early 1990s and published in 1996.
7-11	Equipment Leak Emission Factors for Wells by Region	Allen, David, et al. Measurements of Methane Emissions at Natural Gas Production Sites in the United States – Supporting Information. Proceedings of the National Academy of Sciences of the United States of America. October 2013	US	2013	Detected with FLIR camera, not including leaks from pneumatic pumps or controllers. Specifically leaks in piping, valves, separators, wellheads, and connectors.	478 wells at 146 sites	Direct measurement study conducted in 2012, published in 2013. Cited the use of activity data from EPA Inventory 2011 for activity basis of national NG well estimate.
		Townsend-Small, Amy, et al. Emissions from Coalbed and Natural Gas Methane from Abandoned Oil and Gas Wells in the United States. Geophysical Research Letters, 43, 2283-2290. 2016	US	2016	Screening (using remote methane leak detector or detecto-pak infrared) then measurement of emission rates using combination of static and dynamic flux chambers with CH_4 concentration analyzers.	138 oil and gas wells	Direct measurement study conducted in September through December 2015, published in March 2016.

Table Number	Table Title	Data Source(s)	Location	Year Published	Measurement Approach	Sample Size	Original Data Source
		Jeff Kuo, Travis C. Hicks, Brian Drake & Tat Fu Chan (2015) Estimation of methane emission from California natural gas industry, Journal of the Air & Waste Management Association, 65:7, 844-855.	US - California	2015	Hi-Flow sampler and Bagging	25 facilities with 95,157 components surveyed	Direct measurement study
7.2.2.3 Onshore Oil and Gas Exploration and Production – Component Level Average Emission Factor							
7-12	EPA Average Oil and Gas Production Equipment Leak Emission Factors	U.S. Environmental Protection Agency (EPA). Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017, EPA Office of Air Quality Planning and Standards, November 1995.	US	1995	Derived	Derived from bagging data from 24 oil and gas production facilities	API. Emission Factors for Oil and Gas Production Operations, API Publication Number 4615, January 1995. API. Fugitive Hydrocarbon Emissions from Oil and Gas Production Operations, API 4589, Star Environmental, 1993.
7-13	API Oil and Natural Gas Production Average Equipment Leak Emission Factors	American Petroleum Institute (API). Emission Factors for Oil and Gas Production Operations, API Publication Number 4615, Health and Environmental Sciences Department, January 1995.	US	1995	Document not publically available without purchase. Data source referenced in USEPA GHGRP Regulatory Program.		

Table Number	Table Title	Data Source(s)	Location	Year Published	Measurement Approach	Sample Size	Original Data Source
7-14	Canadian Natural Gas Facility Average Equipment Leak Emission Factors	Clearstone Engineering Ltd.. A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry, Volume 5, September 2004	Canada	2004	Document not publically available without purchase.		
7-15	Canadian Oil Facility Average Equipment Leak Emission Factors	Clearstone Engineering Ltd.. A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry, Volume 5, September 2004	Canada	2004	Document not publically available without purchase.		
7-16	Onshore Oil and Gas Production and Gathering and Boosting Equipment Leak Emission Factors	U.S. Environmental Protection Agency (USEPA), 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Data reported as of August 2, 2019. Table W-1A. https://ecfr.io/Title-40/sp40.23.98.w Part of USEPA GHGRP Regulatory Program.	US	2019	Derived	Derived	GRI. Methane Emissions from the Natural Gas Industry. Volume 8. June 1996. GRI. *Methane Emissions from the Natural Gas Industry*. Volume 6. 1996. API. *Emission Factors for Oil and Gas Production Operations*. Table 9, page 10. API Publication Number 4615. January 1995.

Table Number	Table Title	Data Source(s)	Location	Year Published	Measurement Approach	Sample Size	Original Data Source
7-17	Onshore Oil and Gas Production and Gathering and Boosting Equipment Leak Emission Factors for Western United States from API Study	Pacsi, Adam, et al., Equipment Leak Detection and Quantification at 67 Oil and Gas Sites in the Western United States, Elementa: Science of the Anthropocene (2019) 7:29.	US	2019	OGI and FID	67 sites with OGI and 65 with FID	Direct measurement study conducted between June and December 2015 and published in 2019.
7-18	Population Average Equipment Leak Emission Factors in Alberta, Canada, Upstream Oil and Gas	Clearstone Engineering Ltd. Technical Report – Update of Equipment, Component and Fugitive Emission Factors for Alberta Upstream Oil and Gas. 10 June 2018.	Canada	2018	OGI detection and high flow sampler	333 locations operated by 63 different companies	Direct measurement study conducted in August and September of 2017, published in 2018.
7-19	Component-Level Emission Factors for Components on Production Wellheads in California, USA	Jeff Kuo, Travis Hicks, Brian Drake, Tat Fu Chan (2015) Estimation of Methane Emission from California Natural Gas Industry, Journal of Air and Waste Management Association, 65:7, 844-855.	US - California	2015	Hi-Flow sampler and Bagging	25 facilities with 95,157 components surveyed	Direct measurement study conducted in 2012

Table Number	Table Title	Data Source(s)	Location	Year Published	Measurement Approach	Sample Size	Original Data Source
7-20	Component-Level Emission Factors for Components on Production and Processing Equipment in California, USA	Jeff Kuo, Travis Hicks, Brian Drake, Tat Fu Chan (2015) Estimation of Methane Emission from California Natural Gas Industry, Journal of Air and Waste Management Association, 65:7, 844-855.	US - California	2015	Hi-Flow sampler and Bagging	25 facilities with 95,157 components surveyed	Direct measurement study conducted in 2012
7-21	Emission Factors for Equipment Leak Emissions after the Implementation of DI&M Program in Upstream Gas Segments	CCAC O&G Methane Partnership – Technical Guidance Document Number 2: Fugitive Component and Equipment Leaks. Climate & Clean Air Coalition. March 2017	Not specified	2017	Derived	Derived	CAPP, Update of Fugitive Equipment Leak Emission Factors, published in 2014
7-22	Emission Factors for Equipment Leak Emissions after the Implementation of DI&M Program in Upstream Oil Segments	CCAC O&G Methane Partnership – Technical Guidance Document Number 2: Fugitive Component and Equipment Leaks. Climate & Clean Air Coalition. March 2017	Not specified	2017	Derived	Derived	CAPP, Update of Fugitive Equipment Leak Emission Factors, published in 2014

Table Number	Table Title	Data Source(s)	Location	Year Published	Measurement Approach	Sample Size	Original Data Source
7.2.2.4 Onshore Oil and Gas Exploration and Production – Component Level OGI Leaker Factors							
7-23	Default Whole Gas Leaker Emission Factors; Surveys using 40 CFR §98.234(a)(1)-(6)	U.S. Environmental Protection Agency (USEPA), 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Data reported as of August 2, 2019. Table W-1E. Part of USEPA GHGRP Regulatory Program.	US	2019	Derived	Derived	API. Emission Factors for Oil and Gas Production Operations. Table 10, page 16. API Publication Number 4615. January 1995.
7-24	Default Whole Gas Leaker Emission Factors; Method 21 Surveys at 500 ppmv Leak Detection Threshold	U.S. Environmental Protection Agency (USEPA), 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Data reported as of August 2, 2019. Table W-1E. Part of USEPA GHGRP Regulatory Program.	US	2019	Derived	Derived	API. Emission Factors for Oil and Gas Production Operations. Table 10, page 16. API Publication Number 4615. January 1995.
7-25	Canadian Leaker Emission Factors for Upstream Oil and Gas Sites	Clearstone Engineering Ltd. Technical Report – Update of Equipment, Component and Fugitive Emission Factors for Alberta Upstream Oil and Gas. 10 June 2018.	Canada	2018	OGI detection and high flow sampler	333 locations operated by 63 different companies	Direct measurement study conducted in August and September of 2017, published in 2018.

Table Number	Table Title	Data Source(s)	Location	Year Published	Measurement Approach	Sample Size	Original Data Source
7.2.2.5 Onshore Oil and Gas Exploration and Production – Screening Range Factor							
7-26	EPA Onshore Oil and Natural Gas Production Equipment Leak Screening Emission Factors	U.S. Environmental Protection Agency (EPA). Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017, EPA Office of Air Quality Planning and Standards, November 1995, Table 2-8.	US	1995	Derived	Derived from bagging data from 24 oil and gas production facilities	API. Emission Factors for Oil and Gas Production Operations, API Publication Number 4615, January 1995. API. Fugitive Hydrocarbon Emissions from Oil and Gas Production Operations, API 4589, Star Environmental, 1993.
7-27	API Onshore Oil and Natural Gas Production Equipment Leak Screening Emission Factors	API. Emission Factors for Oil and Gas Production Operations, API Publications No. 4615, Health and Environmental Services Department, January 1995, Table ES-2.	US	1995	Document not publically available without purchase. Data source referenced in USEPA GHGRP Regulatory Program.		
7-28	Alternative Leak/No-Leak Emission Factors for Equipment Leaks with OGI Technologies	CCAC O&G Methane Partnership – Technical Guidance Document Number 2: Fugitive Component and Equipment Leaks. Climate & Clean Air Coalition. March 2017	Not specified	2017	Derived	Derived	Cites Epperson et al. study published in 2007 (Epperson D., Siegell J., Ritter K. Derivation of new emission factors for quantification of mass emissions when using optical gas imaging for detecting leaks. Lev-On M1. J Air Waste Manag Assoc. 2007) which cites

Table Number	Table Title	Data Source(s)	Location	Year Published	Measurement Approach	Sample Size	Original Data Source
							data from API Publication No. 310 from 1997.
7.2.3.1 Gathering and Boosting – Facility Level							
Unnumbered table presented in section 7.2.3	N/A	Zimmerle, Daniel, et al., Methane Emissions from Gathering Compressor Stations in the US. Environmental Science & Technology. 14 May 2020.	US	2020	OGI and High flow sampler	180 facilities	Zimmerle study conducted in 2017, study published in 2019. (Characterization of Methane Emissions From Gathering Compressor Stations: Final Report. Energy Institute). Greenhouse Gas Reporting Program Subpart W, activity data from 2017.
7.2.3.2 Gathering and Boosting – Equipment Level							
Unnumbered table presented in section 7.2.3	N/A	EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 – 2017.	US	2019	These values were calculated using 2017 year-specific GHGRP Subpart W data by region.	Not applicable	Not applicable

Table Number	Table Title	Data Source(s)	Location	Year Published	Measurement Approach	Sample Size	Original Data Source
7-29	Equipment-Level Emission Factors for Equipment Leaks from Gathering and Boosting	Zimmerle, Daniel, et al., Methane Emissions from Gathering Compressor Stations in the US. Environmental Science & Technology. 14 May 2020.	US	2020	OGI and High flow sampler	180 facilities	Zimmerle study conducted in 2017, study published in 2019. Greenhouse Gas Reporting Program Subpart W, activity data from 2017.
7.2.3.3 Gathering and Boosting – Component Level Average Emission Factor							
7-30	Natural Gas Plant, Gathering Compressor Stations, and Well Site Average Equipment Leak Emission Factors	U.S. Environmental Protection Agency (EPA). EPA Phase II Aggregate Site Report: Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites, Technical Report, prepared by National Gas Machinery Laboratory, Clearstone Engineering, Ltd., and Innovative Environmental Solutions, Inc., March 2006, Table 4.	US	2006	HiFlow Sampler	Based on surveys at five gas processing plants, seven gathering compressor stations, and 12 well sites.	Direct measurement study conducted in 2004 and 2005, published in 2006.
7-31	Population Equipment Leak Emission Factors for Components in Gathering and Boosting	Zimmerle, Daniel, et al., Characterization of Methane Emissions from Gathering Compressor Stations: Final Report. Energy Institute – Colorado State University. 2019	US	2019	OGI and High flow sampler	Field measurements were made at 180 facilities in 11 U.S. states during June-November 2017. Measured facilities were sampled from 1705 partner facilities located in	Incorporated data from GSI Environmental Inc. study (*Integrated Component-Specific Measurements to Develop Emission Factors for Compressors and Gas Gathering Lines*)

Table Number	Table Title	Data Source(s)	Location	Year Published	Measurement Approach	Sample Size	Original Data Source
						28 American Association of Petroleum Geologists (AAPG) basins.	conducted in 2017-2018, published in 2018.
7.2.3.3 Gathering and Boosting – Component Level OGI Leaker Factors							
7-32	Leaker Emission Factors for Components in Gathering and Boosting	Zimmerle, Daniel, et al., Characterization of Methane Emissions from Gathering Compressor Stations: Final Report. Energy Institute – Colorado State University. 2019.	US	2019	OGI and High flow sampler	Field measurements were made at 180 facilities in 11 U.S. states during June-November 2017. Measured facilities were sampled from 1705 partner facilities located in 28 American Association of Petroleum Geologists (AAPG) basins.	Incorporated data from GSI Environmental Inc. study conducted in 2017 - 2018, published in 2018.

Table 7-3. Facility-Level Average Equipment Leak Emission Factors for Offshore Production

Source	**Methane Emission Factor, Original Units**	**Methane Content, (mole %)**	**Methane Emission Factor, Converted to Tonne Basis** [a]	**Uncertainty** [b] **(± %)**	**Converted Whole Gas Emission Factor**
Offshore Oil Production [c]	0.2069 lb CH_4/ bbl produced	78.8	9.386E-05 tonne CH_4/bbl produced	Not specified	6.21 scf gas/bbl produced
			5.903E-04 tonne CH_4/m^3 produced		1.11 m^3 gas/m^3 produced
Offshore Gas Production [d]	22.93 lb CH_4/10^6 scf produced	78.8	1.040E-02 tonne CH_4/10^6 scf produced		688.1 scf gas/10^6 scf produced
			3.673E-01 tonne CH_4/10^6 m^3 produced		688.1 m^3 gas/10^6 m^3 produced

Footnotes and Sources:

[a] The emission factors can be adjusted based on the relative concentrations of CH_4 and CO_2 to estimate CO_2 emissions.

[b] Uncertainty is based on a 95% confidence interval from the data used to develop the original emission factor.

[c] Assumed to be 40% of the onshore oil production emission factor exhibited in Table 7-8.

[d] EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 – 2017. 2019. These values were calculated using 2017 year-specific GHGRP Subpart W data by region.

Note: These factors, used in the USEPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017 (EPA 2019), are updated annually based on data reported from operators under the GHGRP. Note: Deepwater is defined by the US Department of the Interior Minerals Management Service as water depths greater than or equal to 1,000 ft (305 m).

[d] Assumed to be 40% of the onshore gas production emission factor exhibited in Table 7-8.

Most of the factors shown in the tables in this chapter are CH_4 emission factors. In addition to CH_4, CO_2 also may be released from fugitive equipment leaks if CO_2 is present in the gas stream (e.g., enhanced oil recovery operations and some gas production operations). Fugitive emission factors from equipment leaks specific to CO_2 are limited in current, publicly available studies. As an approximation, the CH_4 emission factor can be adjusted to account for the CO_2 composition of the gas for fugitive sources from equipment leaks other than underground pipelines. This conversion is shown in the following equation and demonstrated in Exhibit 7-1.

$$\mathrm{CO_2\ EF} = \mathrm{CH_4 EF} \times \left(\frac{\mathrm{MW\ CO_2}}{\mathrm{MW\ CH_4}} \right) \times \left(\frac{\mathrm{mole\%\ CO_2}}{\mathrm{mole\%\ CH_4}} \right) \qquad \text{(Equation 7-1)}$$

or

$$\mathrm{CO_2\ Emissions\ (tonnes/yr)} = \mathrm{CH_4\ Emissions\ (tonnes/yr)} \times \left(\frac{\mathrm{MW\ CO_2}}{\mathrm{MW\ CH_4}} \right) \times \left(\frac{\mathrm{mole\%\ CO_2}}{\mathrm{mole\%\ CH_4}} \right) \qquad \text{(Equation 7-2)}$$

where

EF = emission factor (mass/activity); and

MW = molecular weight (tonne/tonne-mole).

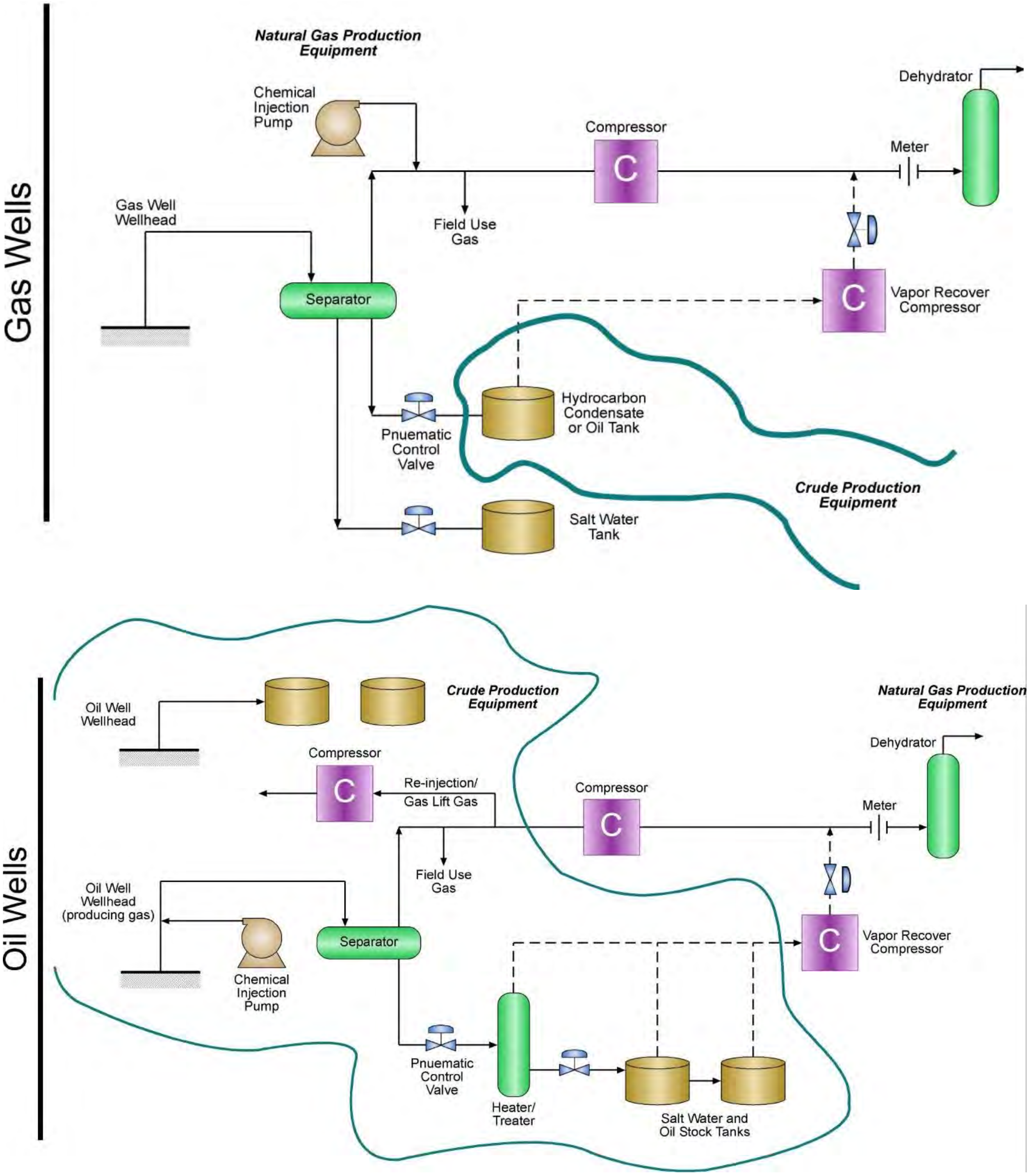

Figure 7-2. Boundaries Between Crude and Natural Gas Production Equipment

Exhibit 7-1 demonstrates the use of facility-level average emission factors for offshore production.

EXHIBIT 7-1: Sample Calculation for Facility-Level Average Fugitive Equipment Leak Emission Factor Approach

INPUT DATA:

An offshore oil production facility has a production throughput of 795 m^3 per day of crude. The CH_4 content of the associated gas is 68 mole %, and the CO_2 content is 4 mole %. Assume that the facility operates continuously throughout the year. Calculate the CH_4 and CO_2 emissions.

CALCULATION METHODOLOGY:

CH4 emissions are calculated using the emission factor for offshore oil production from Table 7-3, and correcting for the actual CH_4 composition of the gas. CO_2 emissions are calculated by the ratio of CH_4 to CO_2 in the produced gas.

$$E_{CH_4} = \frac{795\text{ m}^3}{\text{day}} \times \frac{365\text{ day}}{\text{year}} \times \frac{5.903\times10^{-4}\text{ tonne CH}_4}{\text{m}^3\text{ produced}} \times \frac{0.68\text{ tonne mol CH}_4\text{ actual}}{0.788\text{ tonne mol CH}_4\text{ default}}$$

$$E_{CH_4} = 148\text{ tonnes CH}_4\text{/yr}$$

$$E_{CO_2} = \frac{148\text{ tonnes CH}_4}{\text{yr}} \times \frac{\text{tonne mol CH}_4}{16\text{ tonne CH}_4} \times \frac{\text{tonne mol gas}}{0.68\text{ tonne mol CH}_4} \times \frac{0.04\text{ tonne mol CO}_2}{\text{tonne mol gas}} \times \frac{44\text{ tonne CO}_2}{\text{tonne mol CO}_2}$$

$$E_{CO_2} = 23.9\text{ tonnes CO}_2\text{/yr}$$

7.2.1.2 Equipment Level

This document does not cite any equipment-level emission factors for offshore oil and gas exploration and production.

7.2.1.3 Component Level – Average Emission Factor

The component-level average emission factor approach is based on the number of components in the facility. Where no monitoring data is available, this approach provides a more accurate estimation than equipment or facility level emission factors, since it is based on site-specific component population data. This methodology requires component counts; however, if this information is not available generic counts can be obtained as detailed in Appendix C, Section C.1.2.

It should be noted that many of the component-level average emission factors were developed for estimating TOC (also referred to as THC) or VOC, rather than CH_4. This section includes a methodology for converting the TOC-based emission factors to CH_4 fugitive equipment leak emissions, based on either site-specific data or on default composition by type of facility.

EPA provides the following equation to estimate TOC mass emissions for a given component type:

$$E_{TOC}=FA\times WF_{TOC}\times N \qquad \text{(Equation 7-3)}$$

where

E_{TOC} = emission rate of TOC from all components of a given type in the stream;

F_A = average TOC emission factor for the component type A from the applicable tables;

WF_{TOC} = average weight fraction TOC in the stream (if unknown assume 1.0); and

N = number of components of the given type in the stream.

The weight fraction concentration of TOC within the equipment is needed because equipment with higher TOC concentrations tends to have higher TOC leak rates. When using the average emission factor approach for streams with different TOC concentrations, the components should be grouped according to the TOC weight fraction, prior to applying Equation 7-3.

On the same basis, Equation 7-3 can be restated in terms of CH_4 emissions (a constituent of TOC) by replacing the TOC weight fraction with the weight fraction of CH_4 (WF_{CH4}). The derivation is shown below:

$$E_{TOC} = F_A \times WF_{TOC} \times N$$

(Equation 7-4)

$$E_{CH_4} = E_{TOC} \times \frac{WF_{CH_4}}{WF_{TOC}} \qquad \text{(Equation 7-5)}$$

Combining these equations, the weight fraction of TOC cancels out, resulting in an equation stated in terms of CH_4 emissions, as shown for Equation 7-6.

$$E_{CH_4} = (F_A \times WF_{TOC} \times N) \text{ x } \frac{WF_{CH_4}}{WF_{TOC}} \qquad \text{(Equation 7-6)}$$

$$E_{CH_4} = F_A \times WF_{CH_4} \times N$$

where

E_{CH_4} = emission rate of CH_4 from all components of a given type in the stream; and

WF_{CH_4} = average weight fraction of CH_4.

Table 7-4 provides average fugitive equipment leak emission factors for offshore facilities. Although these emission factors are reported in terms of individual components, the average emission factor approach is intended for application to a population of components.

Table 7-4. API Average Offshore Equipment Leak Emission Factors

Component Type	Emission Factor, Original Units [a], lb TOC/comp/day	Emission Factor, Converted to tonne TOC/comp/hr	Uncertainty (± %)
Valves	0.027	5.14E-07	Not specified
Pump seals	0.010	1.95E-07	
Others	0.367	6.94E-06	
Connectors	0.006	1.08E-07	
Flanges	0.010	1.97E-07	
Open-ended lines	0.054	1.01E-06	

Footnote and Source:

[a] American Petroleum Institute (API). *Emission Factors for Oil and Gas Production Operations*, API Publication Number 4615, Health and Environmental Sciences Department, January, 1995, Table ES-1.

Table 7-5 also provides average fugitive equipment leak emission factors for offshore facilities. The Norwegian Environment Agency's Sub-Report 2 provides total hydrocarbon (THC) emission factors by service type. For these service type-specific emission factors, component counts are required for each service category, such as valves in gas, light liquid, or heavy liquid service. According to EPA (EPA 1995), gas service is any material that is in a gaseous or vapor state at process conditions. Light liquid service is defined as any material in a liquid state in which the sum of the concentration of individual constituents with a vapor pressure over 0.3 kPa at 20°C is greater than or equal to 20 weight percent, which generally includes naphtha and more volatile oil and gas liquids. A heavy liquid is any liquid that is not in gas/vapor or light liquid service, which would generally include kerosene and less volatile oil and gas liquids.

Table 7-5. Offshore THC Equipment Leak Emission Factors

Component Type	Emission Factor, Original Units [a], lb THC/comp/day	Emission Factor, Converted to tonne THC/comp/hr	Uncertainty (± %)
Service Type - Gas			
Connector	1.10E-02	2.08E-07	Not specified
Flange	2.10E-02	3.97E-07	
Open ended line	1.10E-01	2.08E-06	
Other [b]	4.70E-01	8.88E-06	
Pump	1.30E-01	2.46E-06	
Valve	2.40E-01	4.54E-06	
Service Type – Natural Gas Liquids			
Connector	1.10E-02	2.08E-07	Not specified
Flange	5.80E-03	1.10E-07	
Open ended line	7.40E-02	1.40E-06	
Other [b]	4.00E-01	7.56E-06	
Pump	6.90E-01	1.30E-05	
Valve	1.30E-01	2.46E-06	
Service Type – Heavy Oil (API < 20°)			
Connector	4.00E-04	7.56E-09	Not specified
Flange	2.10E-05	3.97E-10	

Component Type	Emission Factor, Original Units [a], lb THC/comp/day	Emission Factor, Converted to tonne THC/comp/hr	Uncertainty (± %)
Open ended line	7.40E-02	1.40E-06	
Other [b]	1.70E-03	3.21E-08	
Pump	6.90E-01	1.30E-05	
Valve	4.40E-04	8.32E-09	
Service Type – Light Oil (API ≥ 20°)			
Connector	1.10E-02	2.08E-07	Not specified
Flange	5.80E-03	1.10E-07	
Open ended line	7.40E-02	1.40E-06	
Other [b]	4.00E-01	7.56E-06	
Pump	6.90E-01	1.30E-05	
Valve	1.30E-01	2.46E-06	
Service Type – Water/Oil			
Connector	5.80E-03	1.10E-07	Not specified
Flange	1.50E-04	2.83E-09	
Open ended line	1.30E-02	2.46E-07	
Other [b]	7.40E-01	1.40E-05	
Pump	1.30E-03	2.46E-08	
Valve	5.20E-03	9.83E-08	
Service Type – Oil/Water/Gas			
Connector	1.10E-02	2.08E-07	Not specified
Flange	2.10E-02	3.97E-07	
Open ended line	1.10E-01	2.08E-06	
Other [b]	7.40E-01	1.40E-05	
Pump	1.30E-01	2.46E-06	
Valve	2.40E-01	4.54E-06	

Footnote and Source:

[a] Norwegian Environment Agency. *Cold Venting and Fugitive Emissions from Norwegian Offshore Oil and Gas Activities: Module 2 - Emission Estimates and Quantification Methods*, Sub-report 2, 15 March 2016, Table 49.

[b] Norwegian Environment Agency notes that compressor seals are included in the definition of "Other".

The Norwegian Environment Agency's Sub-Report 2 also provides general offshore factors for fugitive equipment leak emissions that are used in the UK Offshore oil and gas industry, seen below in Table 7-6.

Table 7-6. Generic Offshore Equipment Leak Emission Factors

Component Type	Emission Factor, Original Units [a], kg THC/comp/yr	Emission Factor, Converted to tonne THC/comp/hr	Uncertainty (± %)
Flange	0.946	1.08E-07	Not specified
Valve	4.52	5.16E-07	
Open ended line	8.94	1.02E-06	
Pump	1.72	1.96E-07	
Other	60.9	6.95E-06	

Footnote and Source:

[a] Norwegian Environment Agency. *Cold Venting and Fugitive Emissions from Norwegian Offshore Oil and Gas Activities: Module 2 - Emission Estimates and Quantification Methods*, Sub-report 2, 15 March 2016, Table 52. Assumes original emission factor is in units of kg THC/comp/yr. Emission factors should be adjusted by a factor of 1.3 for facilities built between 1980-1988 and by 1.5 for those built before 1980.

An example calculation illustrating the use of component-level fugitive equipment leak emission factors is provided in Exhibit 7-2.

EXHIBIT 7-2: Sample Calculation for Offshore Production Component-Level Average Fugitive Equipment Leak Emission Factor Approach

INPUT DATA:

There are 100 valves, 250 flanges, 3 pump seals, and 2 open ended lines in a stream at an offshore production site. No stream speciation data is available from the facility to quantify methane emissions. Calculate the CH_4 emissions.

CALCULATION METHODOLOGY FOR OFFSHORE CASE:

CH_4 emissions would be calculated using Equation 7-6 and the average TOC emission factor for the components from Table 7-4 as follows. Since data are unavailable on stream composition, use the speciation fractions of the average CH_4 fraction to apply to the TOC fugitive equipment leak emissions from offshore oil and natural gas production from Table C-1 in Appendix C, Section C.1.1.

Valves:

$$E_{CH_4} = \frac{0.027 \text{ lb TOC}}{\text{valve-day}} \times \frac{0.791 \text{ tonne CH}_4}{\text{tonne TOC}} \times \frac{365 \text{ days}}{\text{yr}} \times \frac{\text{tonne}}{2204 \text{ lb}} \times 100 \text{ valves}$$

E_{CH_4}= 0.35 tonnes CH_4/yr

Flanges:

$$E_{CH_4} = \frac{0.010 \text{ lb TOC}}{\text{flange-day}} \times \frac{0.791 \text{ tonne CH}_4}{\text{tonne TOC}} \times \frac{365 \text{ days}}{\text{yr}} \times \frac{\text{tonne}}{2204 \text{ lb}} \times 250 \text{ flanges}$$

E_{CH_4}= 0.33 tonnes CH_4/yr

Pump Seals:

$$E_{CH_4} = \frac{0.010 \text{ lb TOC}}{\text{pump seal-day}} \times \frac{0.791 \text{ tonne CH}_4}{\text{tonne TOC}} \times \frac{8760 \text{ hr}}{\text{yr}} \times \frac{\text{tonne}}{2204 \text{ lb}} \times 3 \text{ pump seals}$$

E_{CH_4}= 0.004 tonnes CH_4/yr

OELs:

$$E_{CH_4} = \frac{0.054 \text{ lb TOC}}{\text{OEL-day}} \times \frac{0.791 \text{ tonne CH}_4}{\text{tonne TOC}} \times \frac{8760 \text{ hr}}{\text{yr}} \times \frac{\text{tonne}}{2204 \text{ lb}} \times 2 \text{ OEL}$$

E_{CH_4}= 0.014 tonnes CH_4/yr

Total CH_4 Emissions from All Components:

E_{CH_4}= 0.35 + 0.33 + 0.004 + 0.014 = 0.70 tonnes CH_4/yr

7.2.1.4 Component Level - Leaker Factors

This document does not cite any specific OGI leaker emission factors for offshore oil and gas exploration and production. The general leaker emission factors presented in Table 7-28 in Section 7.2.2.5 can be used for offshore production, as they are not specific to a sector (CCAC, 2017).

7.2.1.5 Component Level - Screening Range Factors

The screening range factor approach, also called the leak/no-leak approach, is based on monitoring data that have been categorized into two or more ranges. Monitoring data are broken into categories of "leakers", over a certain leak threshold and "non-leakers" that are under that leak screening threshold. For example, for most studies presented in this section, "leakers" are defined as leaks found with U.S. EPA Reference Method 21 readings greater than or equal to 10,000 ppmv, and "non-leakers" with readings less than 10,000 ppmv.

When using the screening range factor approach, the components should be grouped into "streams" where all the components have approximately the same TOC weight fraction and monitoring readings within the same category. The following equation is used in the calculations:

$$E_{TOC} = (F_G \times N_G) + (F_L \times N_L) \qquad \text{(Equation 7-7)}$$

where

E_{TOC} = emission rate of TOC from all components of a given type in the stream;

F_G = TOC emission factor for components with screening values greater than or equal to 10,000 ppmv;

N_G = number of components with screening values greater than or equal to 10,000 ppmv;

F_L = emission factor for components with screening values less than 10,000 ppmv; and

N_L = number of components with screening values less than or equal to 10,000 ppmv.

Methane emissions can be estimated from the TOC emission factors using Equation 7-5.

EPA screening emission factors for oil and gas production are included in Table 7-7 for "leakers" and "non-leakers." Note that these emission factors in Table 7-7 are not facility specific for the leaker emission factors ≥10,000 ppmv.

Table 7-7. API Oil and Gas Offshore Screening Emission Factors

Component Type	Emission Factor, Original Units [a, b], lb TOC/comp/day		Emission Factor, Converted to tonne TOC/comp/hr [b]		Uncertainty (± %)
	< 10,000 ppmV	≥ 10,000 ppmV [c]	< 10,000 ppmV	≥ 10,000 ppmV [c]	
Valves	8.50E-04	3.381	1.61E-08	6.390E-05	Not specified
Connectors	5.11E-04	1.497	9.66E-09	2.829E-05	
Flanges	1.33E-03	4.490	2.51E-08	8.486E-05	
Open-ended Lines	9.40E-04	1.600	1.78E-08	3.024E-05	
Pump Seals	1.03E-02	3.905	1.95E-07	7.380E-05	
Others	3.76E-03	3.846	7.11E-08	7.269E-05	

Footnotes and Sources:

[a] American Petroleum Institute (API). *Emission Factors for Oil and Gas Production Operations*, API Publication No. 4615, Health and Environmental Sciences Department, January 1995, Table ES-2.

[b] NA means not available on the "all facilities" basis. The emission factors for leaking components were developed as a single factor across all facility types. The emission factors for non-leaking components, however, were developed for each facility type.

[c] These screening factors have no specified facility type and are assumed to be applicable for all sectors.

An example calculation illustrating the use of the screening factors approach is provided in Exhibit 7-3.

EXHIBIT 7-3: Sample Calculation for Screening Factor Approach

INPUT DATA:

Assume that there are 100 valves at an offshore facility and that there is no stream composition data available. Five of the valves had a screening value of >10,000 ppmv and the remaining 95 valves had a screening factor of <10,000 ppmv. The stream composition is assumed to be Calculate the CH_4 emissions using the "Valves" screening factor for offshore provided in Table 7-7.

CALCULATION METHODOLOGY:

Because no plant-specific stream composition data is available, the composition data will be assumed .

1. *Calculate CH_4 emissions using the "Offshore Valves" screening factor.* The emission factors in Table 7-8 are in terms of TOC. TOC emissions are calculated using Equation 7-7. Emissions are calculated below, by screening value:

For components screening ≥ 10,000 ppmv:

$$E_{TOC\ \geq 10{,}000} = \frac{6.390 \times 10^{-5}\ \text{tonne TOC}}{\text{valve-hr}} \times 5\ \text{valves}$$

$$E_{TOC\ \geq 10{,}000} = 3.195 \times 10^{-4}\ \text{tonne TOC/hr}$$

For components screening <10,000 ppmv:

$$E_{TOC\ <\ 10{,}000} = \frac{1.61 \times 10^{-8}\ \text{tonne TOC}}{\text{valve-hr}} \times 95\ \text{valves}$$

$$E_{TOC\ <\ 10{,}000} = 1.53 \times 10^{-6}\ \text{tonne TOC/hr}$$

The combined valve emissions are:

$$E_{TOC\ Total} = (3.195 \times 10^{-4}) + (1.53 \times 10^{-6})$$

$$E_{TOC\ Total} = 3.21 \times 10^{-4}\ \text{tonne TOC/hr}$$

Using Equation 7-6, the TOC emissions are converted to CH_4 emissions. From Table C-1, the average stream concentration of CH_4 in offshore production is assumed to be 79.1 weight percent.

$$E_{CH_4} = \frac{3.21 \times 10^{-4}\ \text{tonne TOC}}{\text{hr}} \times \frac{0.791\ \text{tonne CH}_4}{\text{tonne TOC}} \times \frac{8{,}760\ \text{hr}}{\text{yr}}$$

$$E_{CH_4} = 2.22\ \text{tonne CH}_4\text{/yr}$$

7.2.1.6 Correlation Equations Using Method 21 Monitoring

The correlation equation approach predicts the mass emission rate as a function of the screening value for a particular equipment type as detailed in Section 7.1.2.2. Since Method 21 monitoring data is not likely available for upstream operations, use of this approach is not common. If Method 21 monitoring data (i.e., screening values) are available, please refer to Section 7.3 for the detailed approach methodology and correlation equations.

7.2.2 Onshore Oil and Gas Exploration and Production

7.2.2.1 Facility Level

As described in Section 7.1.1, applying average facility-level emission factors is the simplest method for estimating CH_4 emissions from onshore oil and gas exploration and production. Facility-level equipment leak emission factors for onshore oil and gas exploration and production are presented in Table 7-8. If greater accuracy is needed for reporting or to support emission reduction estimates, one of the more rigorous approaches should be used.

Table 7-8 provides separate equipment leak emission factors for oil and gas production operations. However, oil and gas can be produced from the same well. For facilities that produce any natural gas or are equipped similarly to the gas well schematic shown in Figure 7-2, the gas production emission factors should be used. For facilities that do not market the associated gas, or produce only crude or are equipped similar to the oil well schematic shown in Figure 7-2, the oil production emission factors should be used.

Table 7-8. Facility-Level Average Equipment Leak Emission Factors for Onshore Production

Source	**Methane Emission Factor, Original Units**	**Methane Content (mole %)**	**Methane Emission Factor, Converted to Tonne Basis [a]**	**Uncertainty (± %) [b]**	**Converted Whole Gas Emission Factor**
Oil Production [c]	0.5173 lb CH_4/bbl produced	78.8	2.346E-04 tonne CH_4/bbl produced	95.5	15.52 scf gas/bbl produced
			1.476E-03 tonne CH_4/m^3 produced		2.77 m^3 gas/m^3 produced
Gas Production [d]	57.33 lb $CH_4/10^6$ scf produced		2.601E-02 tonne $CH_4/10^6$ scf produced	52.9	1,720.4 scf gas/10^6 scf produced
			9.184E-01 tonne $CH_4/10^6$ m^3 produced		1,720.4 m^3 gas/10^6 m^3 produced

Footnotes and Sources:

[a] The emission factors can be adjusted based on the relative concentrations of CH_4 and CO_2 to estimate CO_2 emissions.

[b] Uncertainty is based on a 95% confidence interval from the data used to develop the original emission factor.

[c] Factors obtained from EPA petroleum methane emissions study; see derivation in Appendix C, Section C.3.1.

[d] Factors obtained from GRI/EPA Study, Vol. 2; see derivation in Appendix C, Section C.3.2.

7.2.2.2 Equipment Level

The equipment-level average emission factor approach allows the equipment leak emission estimate to be tailored to a particular facility based on the population of major equipment at the facility. The method for estimating the emissions using the major equipment approach is presented in the equation below:

$$E_{CH_4\ (or\ CO_2)} = F_{A\ (CH_4\ or\ CO_2)} \times N \qquad \text{(Equation 7-8)}$$

where

$E_{(or)}$ = emission rate of CH_4 (or CO_2) from a population of equipment;

$F_{A\ (or)}$ = applicable average CH_4 or CO_2 emission factor for the major equipment type A; and

N = number of pieces of equipment in the plant/process.

Table 7-9 and Table 7-10 provide equipment leak emission factors for equipment associated with oil and gas exploration and production operations. For facilities where oil and gas are produced from the same well, Figure 7-2 illustrates the boundaries between crude production equipment and natural gas production equipment. The emission factors were developed for separate assessments of natural gas sector equipment versus oil and gas industry equipment (Harrison, 1999; Shires, 2002). Emission factors from Table 7-9 should be applied to counts of equipment associated with crude production and configured similar to the oil well schematic shown in Figure 7-2. Likewise, Table 7-10 emission factors should be applied to natural gas production equipment configured similar to the gas well schematic shown in Figure 7-2. Equipment with minimal to no gas handling should use the emission factors for crude production equipment.

For both Table 7-9 and Table 7-10, the CH_4 emission factors are based on an average CH_4 composition of 78.8 mole % as provided in Table D-4. The emission factors can be adjusted to other CH_4 concentrations by the ratio of the actual CH_4 content to the default value. In addition, in the absence of CO_2-specific emission factors, CO_2 emissions can be approximated from the CH_4 emission factors based on the ratio of CO_2 to CH_4 in the produced gas. The conversion to CO_2 is shown in Equations 7-1 and 7-2 and demonstrated in Exhibit 7-1.

Table 7-9. Equipment Leak Emission Factors for Onshore Crude Production Equipment

Equipment Basis	Original Methane Emission Factor, [a] Original Units		Methane Content, [b] (mole %)	Methane Emission Factor, [b] Converted to Tonne Basis		Uncertainty, (± %) [c]	Whole Gas Emission Factor [b], Converted	
Oil wellheads – heavy crude	0.83	scf CH_4/ well/day	78.8	6.63E-07	tonne CH_4/well/hr	30	0.044	scf gas/well/hr
Oil wellheads – light crude	19.58	scf CH_4/ well/day		1.56E-05	tonne CH_4/well/hr	30	1.035	scf gas/well/hr
Oil pump stations [d]	1.06	lb CH_4/ mile/yr	78.8	5.49E-08	tonne CH_4/mile/hr	Not specified	0.0036	scf gas/mile/hr
				3.41E-08	tonne CH_4/km/hr		0.0023	scf gas/km/hr
Separators – heavy crude	0.85	scf CH_4/ separator/day		6.79E-07	tonne CH_4/ separator/hr	30	0.045	scf gas/ separator/hr
Separators – light crude	51.33	scf CH_4/ separator/day		4.10E-05	tonne CH_4/ separator/hr	30	2.714	scf gas/ separator/hr
Heater treaters – light crude	59.74	scf CH_4/ heater/day		4.77E-05	tonne CH_4/ heater/hr	30	3.159	scf gas/heater/hr
Headers – heavy crude	0.59	scf CH_4/ header/day		4.72E-07	tonne CH_4/ header/hr	30	0.031	scf gas/ header/hr

Equipment Basis	**Original Methane Emission Factor, [a] Original Units**		**Methane Content, [b] (mole %)**	**Methane Emission Factor, [b] Converted to Tonne Basis**		**Uncertainty, (± %) [c]**	**Whole Gas Emission Factor [b], Converted**	
Headers – light crude	202.78	scf CH_4/ header/day		1.62E-04	tonne CH_4/ header/hr	30	10.722	scf gas/ header/hr
Tanks – light crude	34.4	scf CH_4/ tank/day		2.75E-05	tonne CH_4/ tank/hr	30	1.82	scf gas/tank/hr
Small compressors – light crude	46.14	scf CH_4/ compressor/ day		3.69E-05	tonne CH_4/ compressor/hr	100	2.440	scf gas/ compressor/hr
Large compressors – light crude [e]	16,360	scf CH_4/ compressor/ day		1.31E-02	tonne CH_4/ compressor/hr	100	865.1	scf gas/ compressor/hr
Sales areas	40.55	scf CH_4/ area/day		3.24E-05	tonne CH_4/ area/hr	30	2.144	scf gas/area/hr

Footnotes and Sources:

[a] Harrison, M.R., T.M. Shires, R.A. Baker, and C.J. Loughran. *Methane Emissions from the U.S. Petroleum Industry*, *Final Report*, EPA 600/R-99-010, U.S. Environmental Protection Agency, 1999.

[b] Emission factors converted from scf are based on 60 °F and 14.7 psia. The average CH_4 concentration associated with these emission factors provided in Table E-4 is 78.8 mole %. If the actual CH_4 content differs from the default value, the emission factors shown above can be adjusted by the ratio of the site CH_4 content to the default concentration.

[c] Uncertainty was assumed based on engineering judgement (Harrison, et al., 1999).

[d] PSI, 1989.

[e] Large compressors are those with more than three stages of compression.

The emission factors shown in Table 7-9 for crude production equipment are derived from API Report 4615 *Emission Factors for Oil and Gas Production Operations* (API, 1995) and average component counts per equipment (Harrison et al., 1999). Separate emission factors are provided for heavy versus light crude, since heavier crude has less entrained CH_4 and therefore lower emissions. API Report 4638, *Calculation Workbook For Oil and Gas Production Equipment Fugitive Emissions*, designates heavy crude as having an API gravity of less than 20° and light crude as having an API gravity of greater than 20° (API, 1996). Please note that the EPA defines light and heavy crude according to vapor pressure.[3]

Emission factors provided in Table 7-10 are derived from the GRI/EPA U.S. CH_4 emissions study (Harrison, et al., 1996). Emission factors for both CH_4 and CO_2 are provided for gathering pipelines. The derivation of all the emission factors presented in Table 7-10 can be found in Appendix C, Section C.3.2.

Table 7-11 provides a summary of CH_4 equipment leak emission factors from various published studies for production wells in the United States, organized by region and type of well. These emission factors were calculated from direct measurements from leaks in piping, valves, separators, wellheads, and connectors on each well site (Allen, 2016). Note that the California natural gas wellhead emission factor in Table 7-11 below is only applicable for conventional natural gas, not gas that is produced from hydraulic fracturing (Kuo, 2015).

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[3] EPA defines gas/vapor service as material in a gaseous state at operating conditions; light crude as material in a liquid state in which the sum of the concentration of individual constituents with a vapor pressure over 0.3 kilopascals (kPa) at 20 °C is greater than or equal to 20 weight percent; and heavy crude as not in gas/vapor service or light liquid service (EPA, *Protocol for Equipment Leak Emission Estimates*, 1995).

Table 7-10. Equipment Leak Emission Factors for Onshore Natural Gas Production Equipment

Equipment Basis	Reference Methane Emission Factor [a, b], Original Units		Methane Content (mole %)	Methane Emission Factor [c], Converted to Tonne Basis		Uncertainty [d] (± %)	Whole Gas Emission Factor [c], Converted	
Gas wellheads [e]	8,217	scf CH_4/well/yr	78.8	1.80E-05	tonne CH_4/well/hr	25.7	1.19	scf gas/well/hr
Separators [e]	20,174	scf CH_4/separator/yr		4.42E-05	tonne CH_4/separator/hr	87.9	2.92	scf gas/separator/hr
Gas heaters [e]	20,985	scf CH_4/heater/yr		4.60E-05	tonne CH_4/heater/hr	173	3.04	scf gas/heater/hr
Small reciprocating gas compressor [e]	97,023	scf CH_4/compressor/yr		2.12E-04	tonne CH_4/compressor/hr	127	14.06	scf gas/compressor/hr
Large reciprocating gas compressor [e, f]	5.55E+06	scf CH_4/compressor/yr		1.22E-02	tonne CH_4/compressor/hr	202	804	scf gas/compressor/hr
Large reciprocating gas compressor stations [f, g]	8,247	scf CH_4/station/yr		1.81E-05	tonne CH_4/station/hr	126	1.20	scf gas/station/hr
Meters/piping [e]	16,073	scf CH_4/meter/yr		3.52E-05	tonne CH_4/meter/hr	159	2.33	scf gas/meter/hr
Dehydrators [e]	32,561	scf CH_4/dehydrator/yr		7.13E-05	tonne CH_4/dehydrator/hr	45.1	4.72	scf gas/dehydrator/hr
Gathering pipelines [e, h]	826	lb CH_4/mile/yr		4.28E-05	tonne CH_4/mile/hr	113	2.83	scf gas/mile/hr
				2.66E-05	tonne CH_4/km/hr		1.76	scf gas/km/hr

Equipment Basis	Reference Methane Emission Factor [a, b], Original Units		Methane Content (mole %)	Methane Emission Factor [c], Converted to Tonne Basis		Uncertainty [d] (± %)	Whole Gas Emission Factor [c], Converted	
CO_2 from oxidation [e, i]	84.7	lb CO_2/mile/yr		4.38E-06	tonne CO_2/mile-hr	70.2	NA [j]	
				2.72E-06	tonne CO_2/km/hr		NA [j]	
CO_2 from pipeline leaks [e, k]	112.8	lb CO_2/mile/yr		5.84E-06	tonne CO_2/mile/hr	114	5.55	scf gas/mile/hr
				3.63E-06	tonne CO_2/km/hr		3.45	scf gas/km/hr

Footnotes and Sources:

[a] 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.

[b] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, *Final Report*, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[c] Emission factors converted from scfy are based on 60 °F and 14.7 psia. The average CH_4 concentration associated with these emission factors provided in Table D-4 is 78.8 mole %; the average CO_2 concentration (for buried pipelines) also provided in Table D-4 is 2 mole %. If the actual concentration differs from the default value, the emission factors shown above can be adjusted by the ratio of the site concentration to the default concentration.

[d] Uncertainty is based on a 95% confidence interval from the data used to develop the original emission factor.

[e] Emission factor derivation provided in Appendix C, Section C.3.2.

[f] Large compressors are those with more than 3 stage of compression. Large compressor stations are those with five or more compressors.

[g] Because the data used to calculate the reference emission factor was unavailable, the Uncertainty at a 95% confidence interval was calculated based on the Uncertainty at a 90% confidence interval presented in the source assuming a data set size of ten.

[h] More detailed gathering pipeline fugitive emission factors are presented in Appendix C, Section C.3.2.

[i] A portion of CH_4 emitted from underground pipeline leaks is oxidized to form CO_2.

[j] Whole gas factor conversion is not relevant for oxidation of CH_4 to CO_2.

[k] This emission factor is a combination of CO_2 oxidized from methane and native CO_2 in the composition of the gas.

Table 7-11. Equipment Leak Emission Factors for Wells by Region

Type of Well	Methane Emission Factor, Original Units		Methane Content, [g] (mole %)	Methane Emission Factor, Converted to Tonne Basis, tonne CH_4/well-hr	Uncertainty (± %)	Converted Whole Gas Emission Factor, scf gas/well-hr [a]
Region – National United States						
NG Well [b]	33900	scfy CH_4/well	81.6	7.40E-05	36	4.7
Abandoned Oil and Gas Well [c]	1.38	g CH_4/hr/well		1.38E-06	217	0.09
Abandoned Oil and Gas Plugged Well [c]	0.002	g CH_4/hr/well		2.00E-09	150	1.00E-04
Abandoned Oil and Gas Unplugged Wells [c]	10.02	g CH_4/hr/well		1.002E-05	124	0.64
Region – Eastern United States						
NG Well [b]	0.098	scfm CH_4/well	98 [d]	1.1E-04	40	6.0
Abandoned Oil and Gas Well [c]	14.00	g CH_4/hr/well	81.6	1.40E-05	135	0.90
Abandoned Oil and Gas Plugged Well [c]	0.00	g CH_4/hr/well	81.6	0.00	NA	0.0
Abandoned Oil and Gas Unplugged Wells [c]	28.01	g CH_4/hr/well	81.6	2.801E-05	128	1.8
Region – Western United States						
NG Well [b, e]	0.035	scfm CH_4/well	74 [d]	4.0E-05	26	2.8
Abandoned Oil and Gas Well [c]	0.18	g CH_4/hr/well	81.6	1.8E-07	56	1.2E-02
Abandoned Oil and Gas Plugged Well [c]	0.002	g CH_4/hr/well	81.6	2E-09	150	1.0E-04
Abandoned Oil and Gas Unplugged Wells [c]	1.71	g CH_4/hr/well	81.6	1.71E-06	124	0.11
California NG Wellhead [f]	0.0383	tonne CH_4/yr/well	81.6	4.37E-06	Not stated	0.28
Region – Gulf United States						
NG Well [b]	0.052	scfm CH_4/well	90 [d]	6.0E-05	42	3.5

Type of Well	**Methane Emission Factor, Original Units**		**Methane Content, [g] (mole %)**	**Methane Emission Factor, Converted to Tonne Basis, tonne CH_4/well-hr**	**Uncertainty (± %)**	**Converted Whole Gas Emission Factor, scf gas/well-hr [a]**
Region – Mid-continent United States						
NG Well [b]	0.046	scfm CH_4/well	84 [d]	5.3E-05	47	3.3

Footnotes and Sources:

[a] Methane content used to convert to whole gas is 81.6 mole % (GHGI, 2019).

[b] Allen, David, et al. *Measurements of Methane Emissions at Natural Gas Production Sites in the United States – Supporting Information*. Proceedings of the National Academy of Sciences of the United States of America. October 2013. https://doi.org/10.1073/pnas.1304880110.

[c] Townsend-Small, Amy, et al. Emissions from Coalbed and Natural Gas Methane from Abandoned Oil and Gas Wells in the United States. Geophysical Research Letters, 43, 2283-2290. 2016. DOI: 10.1002/2015GL067623.

[d] CH_4 content for these values was back-calculated based on original factors in CH_4 and whole gas.

[e] These emission factors were originally categorized in the study as “Rocky Moutain Region”, but assumed to be applicable for the western United States.

[f] Jeff Kuo, Travis C. Hicks, Brian Drake & Tat Fu Chan (2015) Estimation of methane emission from California natural gas industry, Journal of the Air & Waste Management Association, 65:7, 844-855, DOI: 10.1080/10962247.2015.102592

[g] Where the gas content was not specified, the value was assumed based on GHGI Annex 3.6 Table 3.6-3 for U.S. Production segment Methane Content in Natural Gas by NEMS Region (General Sources). For the lower 48 states, in 2017, methane content at 81.6 mol%. The CH_4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH_4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO2 emissions.

Exhibit 7-4 presents an example of calculating CH_4 emissions using the major equipment emission factors approach for onshore production.

EXHIBIT 7-4: Sample Calculation for Major Equipment Emission Factor Approach

INPUT DATA:

Assume an onshore gas production field located in the United States has 15 gas wellheads, 4 separators, a heater, a small reciprocating compressor, a metering station, and 12 miles of gathering pipelines. The equipment operated continuously for the reporting year. The concentration of the produced gas is 79 mole % CH_4 and 2% CO_2. Calculate total CH_4, and CO_2 emissions.

CALCULATION METHODOLOGY:

1. *Calculate CH_4 emissions.* The emission factors for separators, heaters, small reciprocating compressors, gathering pipelines, and metering stations in onshore gas production are provided in Table 7-10. There are multiple options for gas wellheads and gathering pipelines. For gas wellheads, the national estimate in Table 7-11 or the general emission factor in Table 7-10 are both applicable. For the purposes of this exercise, the emission factor from Table 7-10 will be used.

Emissions are calculated below, by equipment type. Because the facility CH_4 content is approximately the same as the default composition associated with the emissions factors, no adjustment for CH_4 is made.

$$E_{CH_4,\text{ wellheads}} = \frac{1.80\times10^{-5}\text{ tonnes CH}_4}{\text{hr}\times\text{wellhead}} \times \frac{8760\text{ hours}}{\text{year}} \times 15\text{ wellheads}$$

$$\underline{E_{CH_4,\text{ wellheads}} = 2.36\text{ tonnes CH}_4\text{ / yr}}$$

$$E_{CH_4,\text{ separators}} = \frac{4.42\times10^{-5}\text{ tonnes CH}_4}{\text{hr}\times\text{ separator}} \times \frac{8760\text{ hours}}{\text{year}} \times 4\text{ separators}$$

$$\underline{E_{CH_4,\text{ separators}} = 1.55\text{ tonnes CH}_4\text{ / yr}}$$

$$E_{CH_4,\text{ heaters}} = \frac{4.60 \times 10^{-5} \text{ tonnes CH}_4}{\text{hr} \times \text{heater}} \times \frac{8760 \text{ hours}}{\text{year}} \times 1 \text{ heater}$$

$$\underline{E_{CH_4,\text{ heaters}} = 0.40 \text{ tonnes CH}_4 / \text{yr}}$$

EXHIBIT 7-3: Sample Calculation for Major Equipment Emission Factor Approach, continued

$$E_{CH_4,\text{ small recips.}} = \frac{2.12 \times 10^{-4} \text{ tonnes CH}_4}{\text{hr} \times \text{small recip.}} \times \frac{8760 \text{ hours}}{\text{year}} \times 1 \text{ small recip.}$$

$$\underline{E_{CH_4,\text{ small recips.}} = 1.86 \text{ tonnes CH}_4/\text{yr}}$$

$$E_{CH_4,\text{ meter}} = \frac{3.52 \times 10^{-5} \text{ tonnes CH}_4}{\text{hr} \times \text{meter}} \times \frac{8760 \text{ hours}}{\text{year}} \times 1 \text{ meter}$$

$$\underline{E_{CH_4,\text{ meter}} = 0.31 \text{ tonnes CH}_4 / \text{yr}}$$

$$E_{CH_4,\text{ gathering pipe}} = \frac{4.28 \times 10^{-5} \text{ tonnes CH}_4}{\text{hr} \times \text{mile}} \times \frac{8760 \text{ hours}}{\text{year}} \times 12 \text{ miles}$$

$$\underline{E_{CH_4,\text{ gathering pipe}} = 4.50 \text{ tonnes CH}_4 / \text{yr}}$$

Total CH_4 emissions are calculated by summing the individual equipment CH_4 emissions, as shown below.

$$E_{CH_4\text{, total}} = \frac{2.36\text{ tonnes}}{\text{yr}} + \frac{1.55\text{ tonnes}}{\text{yr}} + \frac{0.40\text{ tonnes}}{\text{yr}} + \frac{1.86\text{ tonnes}}{\text{yr}} + \frac{0.31\text{ tonnes}}{\text{yr}}$$

$$\underline{E_{CH_4\text{, total}} = 6.48\text{ tonnes } CH_4\text{ / yr}}$$

2. *Calculate CO_2 emissions.* CO_2 emissions result from CO_2 present in the gas stream. For non-pipeline sources, it is assumed that the CO_2 leak rate is based on the CH_4 emission rate, but adjusted for the ratio of CO_2 to CH_4 in the gas.

$$E_{CO_2\text{, non-pipeline sources}} = \frac{6.48\text{ tonnes } CH_4}{\text{yr}} \times \frac{\text{tonne mole } CH_4}{16\text{ tonnes } CH_4} \times \frac{0.02\text{ tonne mole } CO_2}{0.79\text{ tonne mole } CH_4} \times \frac{44\text{ tonnes } CO_2}{\text{tonne mole } CO_2}$$

$$\underline{E_{CO_2\text{, non-pipeline sources}} = 0.45\text{ tonnes } CO_2\text{/yr}}$$

7.2.2.3 Component Level – Average Emission Factor

The component-level average equipment leaks emission factor approach is based on the number of components in the facility. Where no monitoring data is available, this approach provides a more accurate estimation than equipment or facility level emission factors, since it is based on site-specific component population data. This methodology requires component counts; however, if this information is not available generic counts can be obtained as detailed in Appendix C, Section C.1.2.

Details on the methodologies and equations used to estimate TOC mass emissions for a given component type are included in Section 7.2.1.

For some emission factors, component counts are required for each service category, such as valves in gas, light liquid, or heavy liquid service. According to EPA (EPA 1995), gas service is any material that is in a gaseous or vapor state at process conditions. Light liquid service is defined as any material in a liquid state in which the sum of the concentration of individual constituents with a vapor pressure over 0.3 kPa at 20°C is greater than or equal to 20 weight percent, which generally includes naphtha and more volatile oil and gas liquids. A heavy liquid is any liquid that is not in gas/vapor or light liquid service, which would generally include kerosene and less volatile oil and gas liquids.

EPA average emission factors for oil and gas production facilities are provided in Table 7- 12 (EPA, 1995). Although these emission factors are reported in terms of individual components, the average emission factor approach is intended for application to a population of components. Note also that the emission factors in Table 7-12 are service specific.

Please note that unlike EPA, API Report 4615 designates heavy crude as having an API gravity of less than 20° and light crude as having an API gravity of greater than 20°. The emission factors provided in Table 7-13 are facility-specific and not service-specific. For example, a heavy-crude production facility should use the heavy-crude emission factors provided in Table 7-13 for all streams including any gas streams at the site. Thus, the gas production emission factors would not be used to estimate gaseous stream equipment leak emissions at the heavy-crude production facility. Note also that these emission factors can be converted to a CH_4 basis using Equation 7-4.

Table 7-14 and Table 7-15 provide additional oil and gas production facility average equipment leaks emission factors for Canadian facilities. Note that Table 7-14 and Table 7-15 are applicable in the Onshore Production segment as well as the Processing segment (see Section 7.3.1 for Natural Gas Processing).

Table 7-12. EPA Average Oil and Gas Production Equipment Leak Emission Factors

Component – Service [a]	Emission Factor, Original Units, kg gas/hr/comp [b]	Methane Content, [c] (mole %)	Methane Emission Factor, [d] tonne CH_4/hr/comp	Uncertainty (± %)	Converted Whole Gas Emission Factor, [d, e] scf gas/hr/comp
Valves – gas	4.5E-03	81.6	2.94E-06	Not specified	1.88E-01
Valves – heavy oil	8.4E-06		5.48E-09		3.51E-04
Valves – light oil	2.5E-03		1.63E-06		1.05E-01
Valves – water/oil	9.8E-05		6.39E-08		4.10E-03
Connectors – gas	2.0E-04		1.30E-07		8.36E-03
Connectors – heavy oil	7.5E-06		4.89E-09		3.14E-04
Connectors – light oil	2.1E-04		1.37E-07		8.78E-03
Connectors – water/oil	1.1E-04		7.18E-08		4.60E-03
Flanges – gas	3.9E-04		2.54E-07		1.63E-02
Flanges – heavy oil	3.9E-07		2.54E-10		1.63E-05
Flanges – light oil	1.1E-04		7.18E-08		4.60E-03
Flanges – water/oil	2.9E-06		1.89E-09		1.21E-04
Open-ended lines – gas	2.0E-03		1.30E-06		8.36E-02
Open-ended lines – heavy oil	1.4E-04		9.13E-08		5.85E-03
Open-ended lines – light oil	1.4E-03		9.13E-07		5.85E-02
Open-ended lines – water/oil	2.5E-04		1.63E-07		1.05E-02
Pump Seals – gas	2.4E-03		1.57E-06		1.00E-01

Component – Service [a]	Emission Factor, Original Units, kg gas/hr/comp [b]	Methane Content, [c] (mole %)	Methane Emission Factor, [d] tonne CH_4/hr/comp	Uncertainty (± %)	Converted Whole Gas Emission Factor, [d, e] scf gas/hr/comp
Pump Seals – light oil	1.3E-02		8.48E-06		5.44E-01
Pump Seals – water/oil	2.4E-05		1.57E-08		1.00E-03
Others – gas	8.8E-03		5.74E-06		3.68E-01
Others – heavy oil	3.2E-05		2.09E-08		1.34E-03
Others – light oil	7.5E-03		4.89E-06		3.14E-01
Others – water/oil	1.4E-02		9.13E-06		5.85E-01

Footnotes and Sources:

[a] EPA defines light liquids as liquids for which the sum of the concentration of individual constituents with a vapor pressure over 0.3 kPa at 20 °C is greater than or equal to 20 weight percent. EPA defines heavy liquids as liquids not in gas/vapor or light liquid service.

[b] U.S. Environmental Protection Agency (EPA). *Protocol for Equipment Leak Emission Estimates*, EPA-453/R-95-017, EPA Office of Air Quality Planning and Standards, November 1995, Table 2-4.

[c] Gas content taken from GHGI Annex 3.6 Table 3.6-3 for U.S. Production segment Methane Content in Natural Gas by NEMS Region (General Sources). For the lower 48 states, in 2017, methane content at 81.6 mol%. The CH_4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH_4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

[d] Assumes average gas molecular weight of 20 lb/lb-mole.

[e] CH_4 emission factors converted from scf are based on 60°F and 14.7 psia.

Table 7-13. API Oil and Natural Gas Production Average Equipment Leak Emission Factors

Component – Facility Type [a]	Emission Factor [b], Original Units, lb TOC/comp/hr	Emission Factor, Converted to tonne TOC/comp/hr	Uncertainty (± %)
Valves – gas production	1.39E-01	1.39E-04	Not specified
Valves – heavy crude production	6.86E-04	6.86E-07	
Valves – light crude production	7.00E-02	7.00E-05	
Connectors – gas production	1.70E-02	1.70E-05	
Connectors – heavy crude production	4.22E-04	4.22E-07	
Connectors – light crude production	8.66E-03	8.66E-06	
Flanges – gas production	6.23E-03	6.23E-06	
Flanges – heavy crude production	1.16E-03	1.16E-06	
Flanges – light crude production	4.07E-03	4.07E-06	
Open-ended lines – gas production	3.63E-02	3.63E-05	
Open-ended lines – heavy crude production	8.18E-03	8.18E-06	
Open-ended lines – light crude production	6.38E-02	6.38E-05	
Pump Seals – gas production	1.03E-02	1.03E-05	
Pump Seals – light crude production	1.68E-02	1.68E-05	
Others – gas production	4.86E-01	4.86E-04	
Others – heavy crude production	3.70E-03	3.70E-06	
Others – light crude production	3.97E-01	3.97E-04	

Footnotes and Sources:

[a] These emission factors are facility specific, not service specific. For example, a facility producing light crude would apply the light crude production emission factors regardless of service type. API Publication 4615 defines light crude as oil with an API gravity of 20 or more, and heavy crude as oil with an API gravity of less than 20.

[b] American Petroleum Institute (API). *Emission Factors for Oil and Gas Production Operations*, API Publication Number 4615, Health and Environmental Sciences Department, January, 1995, Table ES-1.

Table 7-14. Canadian Natural Gas Facility Average Equipment Leak Emission Factors

Component – Service	**Emission Factor [a], Original Units kg THC/comp/hr**	**Emission Factor, Converted to Tonne Basis, tonne THC/component-hr**	**Uncertainty [b, c] (± %)**
Valves - fuel gas	2.81E-03	2.81E-06	17
Valves - light liquid	3.52E-03	3.52E-06	19
Valves - gas/vapor - all	2.46E-03	2.46E-06	15
Valves - gas/vapor - sour	1.16E-03	1.16E-06	31
Valves - gas/vapor - sweet	2.81E-03	2.81E-06	17
Connectors - fuel gas	8.18E-04	8.18E-07	32
Connectors - light liquid	5.51E-04	5.51E-07	111
Connectors - gas/vapor - all	7.06E-04	7.06E-07	31
Connectors - gas/vapor - sour	1.36E-04	1.36E-07	72
Connectors - gas/vapor - sweet	8.18E-04	8.18E-07	32
Control valves - fuel gas	1.62E-02	1.62E-05	27
Control valves - light liquid	1.77E-02	1.77E-05	45
Control valves - gas/vapor - all	1.46E-02	1.46E-05	23
Control valves - gas/vapor - sour	9.64E-03	9.64E-06	4
Control valves - gas/vapor - sweet	1.62E-02	1.62E-05	27
Pressure relief valves - fuel gas and gas/vapor	1.70E-02	1.70E-05	98
Pressure relief valves - light liquid	5.39E-03	5.39E-06	80
Pressure regulators - fuel gas and gas/vapor	8.11E-03	8.11E-06	238
Pressure regulators - gas/vapor - sour	4.72E-05	4.72E-08	126
Pressure regulators - gas/vapor - sweet	8.39E-03	8.39E-06	239
Open ended lines - fuel gas	4.67E-01	4.67E-04	172

Component – Service	Emission Factor [a], Original Units kg THC/comp/hr	Emission Factor, Converted to Tonne Basis, tonne THC/component-hr	Uncertainty [b, c] (± %)
Open ended lines - light liquid	1.83E-02	1.83E-05	127
Open ended lines - gas/vapor - all	4.27E-01	4.27E-04	161
Open ended lines - gas/vapor - sour	1.89E-01	1.89E-04	127
Open ended lines - gas/vapor - sweet	4.67E-01	4.67E-04	172
Chemical injection pumps - fuel gas and gas/vapor	1.62E-01	1.62E-04	60
Compressor seals - fuel gas and gas/vapor	7.13E-01	7.13E-04	36
Compressor starts - fuel gas	6.34E-03	6.34E-06	25
Controllers - fuel gas and gas/vapor	2.38E-01	2.38E-04	27
Pump seals - light liquid	2.32E-02	2.32E-05	136

Footnotes and Sources:

[a] Clearstone Engineering Ltd.. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry, Volume 5*, September 2004.

[b] Uncertainty based on 95% confidence interval from the data used to develop the original emission factor.

[c] Original emission factors were presented with upper and lower confidence limits. To be conservative, the larger % was chosen to represent the full % uncertainty of the mean value.

Table 7-15. Canadian Oil Facility Average Equipment Leak Emission Factors

Component – Service	Emission Factor [a], Original Units kg THC/comp/hr	Emission Factor, Converted to Tonne Basis, tonne THC/comp/hr	Uncertainty [b] (± %)
Valves - fuel gas and gas/vapor	1.51E-03	1.51E-06	79
Valves - heavy liquid	8.40E-06	8.40E-09	19
Valves - light liquid	1.21E-03	1.21E-06	19
Connectors - fuel gas and gas/vapor	2.46E-03	2.46E-06	15
Connectors - heavy liquid	7.50E-06	7.50E-09	111
Connectors - light liquid	1.90E-04	1.90E-07	111

Component – Service	**Emission Factor [a], Original Units kg THC/comp/hr**	**Emission Factor, Converted to Tonne Basis, tonne THC/comp/hr**	**Uncertainty [b] (± %)**
Control valves - fuel gas and gas/vapor	1.46E-02	1.46E-05	21
Control valves - light liquid	1.75E-02	1.75E-05	44
Pressure relief valves - fuel gas and gas/vapor	1.63E-02	1.63E-05	80
Pressure relief valves - heavy liquid	3.20E-05	3.20E-08	80
Pressure relief valves - light liquid	7.50E-02	7.50E-05	80
Pressure regulators - fuel gas and gas/vapor	6.68E-03	6.68E-06	238
Open ended lines - fuel gas and gas/vapor	3.08E-01	3.08E-04	129
Open ended lines - light liquid	3.73E-03	3.73E-06	127
Chemical injection pumps - fuel gas and gas/vapor	1.62E-01	1.62E-04	60
Compressor seals - fuel gas and gas/vapor	8.05E-01	8.05E-04	36
Compressor starts - fuel gas	6.34E-03	6.34E-06	25
Controllers - fuel gas and gas/vapor	2.38E-01	2.38E-04	27
Pump seals - heavy liquid	3.20E-05	3.20E-08	136
Pump seals - light liquid	2.32E-02	2.32E-05	136

Footnotes and Sources:

[a] Clearstone Engineering Ltd.. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry, Volume 5*, September 2004.

[b] Uncertainty based on 95% confidence interval from the data used to develop the original emission factor.

Table 7-16 provides whole gas emission factors applicable for Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting by service type and location from the Greenhouse Gas Reporting Program (GHGRP) Subpart W. Note that GHGRP defines light crude service as having an API gravity of greater than or equal to 20° and heavy crude service as having an API gravity of less than 20° (GHGRP, 2019).

Table 7-16. Onshore Oil and Gas Production and Gathering and Boosting Equipment Leak Emission Factors

Component – Service Type	Original Emission Factor, scf gas/comp/hr [a, b]	Methane Content (mole %) [c]	Converted Methane Emission Factor, tonne CH_4/comp/hr [d]	Uncertainty (± %)	Converted Methane Emission Factor, scf CH_4/comp/hr [d]
Region – Eastern United States					
Valve – Gas Service	2.70E-02	81.6	4.22E-07	Not specified	2.20E-02
Connector – Gas Service	3.00E-03		4.68E-08		2.45E-03
Open-ended Line – Gas Service	6.10E-02		9.52E-07		4.98E-02
Pressure Relief Valve – Gas Service	4.00E-02		6.25E-07		3.26E-02
Valve – Light Crude Service	5.00E-02		7.81E-07		4.08E-02
Flange – Light Crude Service	3.00E-03		4.68E-08		2.45E-03
Connector – Light Crude Service	7.00E-03		1.09E-07		5.71E-03
Open-ended Line – Light Crude Service	5.00E-02		7.81E-07		4.08E-02
Pump – Light Crude Service	1.00E-02		1.56E-07		8.16E-03
Other – Light Crude Service [e]	3.00E-01		4.68E-06		2.45E-01
Valve – Heavy Crude Service	5.00E-04		7.81E-09		4.08E-04
Flange – Heavy Crude Service	9.00E-04		1.41E-08		7.34E-04
Connector (other) – Heavy Crude Servi	3.00E-04		4.68E-09		2.45E-04
Open-ended Line – Heavy Crude Servic	6.00E-03		9.37E-08		4.90E-03

Component – Service Type	Original Emission Factor, scf gas/comp/hr [a, b]	Methane Content (mole %) [c]	Converted Methane Emission Factor, tonne CH_4/comp/hr [d]	Uncertainty (± %)	Converted Methane Emission Factor, scf CH_4/comp/hr [d]
Other – Heavy Crude Service [e]	3.00E-03		4.68E-08		2.45E-03
Region – Western United States					
Valve – Gas Service	1.21E-01	81.6	1.89E-06	Not specified	9.87E-02
Connector – Gas Service	1.70E-02		2.65E-07		1.39E-02
Open-ended Line – Gas Service	3.10E-02		4.84E-07		2.53E-02
Pressure Relief Valve – Gas Service	1.93E-01		3.01E-06		1.57E-01
Valve – Light Crude Service	5.00E-02		7.81E-07		4.08E-02
Flange – Light Crude Service	3.00E-03		4.68E-08		2.45E-03
Connector (other) – Light Crude Servic	7.00E-03		1.09E-07		5.71E-03
Open-ended Line – Light Crude Service	5.00E-02		7.81E-07		4.08E-02
Pump – Light Crude Service	1.00E-02		1.56E-07		8.16E-03
Other – Light Crude Service [e]	3.00E-01		4.68E-06		2.45E-01
Valve – Heavy Crude Service	5.00E-04		7.81E-09		4.08E-04
Flange – Heavy Crude Service	9.00E-04		1.41E-08		7.34E-04
Connector (other) – Heavy Crude Servi	3.00E-04		4.68E-09		2.45E-04
Open-ended Line – Heavy Crude Servic	6.00E-03		9.37E-08		4.90E-03
Other – Heavy Crude Service [d]	3.00E-03		4.68E-08		2.45E-03

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (USEPA), 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Data reported as of August 2, 2019. Table W-1A. https://ecfr.io/Title-40/sp40.23.98.w.

[b] For multi-phase flow that includes gas, use gas service emission factors (GHGRP, 2019).

[c] Gas content taken from GHGI Annex 3.6 Table 3.6-3 for U.S. Production segment Methane Content in Natural Gas by NEMS Region (General Sources). For the lower 48 states, in 2017, methane content at 81.6 mol%. The CH_4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH_4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

[d] Methane emission factors converted from whole gas are based on 60°F and 14.7 psia.

[e] "Other" category includes instruments, loading arms, pressure relief valves, stuffing boxes, compressor seals, dump lever arms, and vent.

Table 7-17 also provides whole gas emission factors applicable for Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting by service type and by region (Western United States). Note that this study does not claim national representativeness and therefore should not be used for components located outside of the Western United States (Pacsi, 2019).

Table 7-17. Onshore Oil and Gas Production and Gathering and Boosting Equipment Leak Emission Factors for Western United States from API Study

Component	**Original Emission Factor, scf gas/comp/hr** [a]	**Methane Content,** [b] **(mole %)**	**Converted Methane Emission Factor, tonne CH_4/comp/hr** [c]	**Uncertainty (± %)**	**Converted Methane Emission Factor, scf CH_4/comp/hr** [c]
Service Type – Gas Service					
Valve	3.30E-02	81.6	5.15E-07	Not specified	2.69E-02
Connector	1.10E-02		1.72E-07		8.98E-03
Open-ended Line	2.25E-01		3.51E-06		1.84E-01
Pressure relief valve	7.00E-03		1.09E-07		5.71E-03
Flange	2.70E-02		4.22E-07		2.20E-02
Service Type – Light Liquid Service					
Valve	1.00E-02	81.6	1.56E-07	Not specified	8.16E-03
Connector	1.00E-03		1.56E-08		8.16E-04
Open-ended Line [d]	0.00E+00		0.00E+00		0.00E+00
Pressure relief valve [d]	0.00E+00		0.00E+00		0.00E+00
Flange [d]	0.00E+00		0.00E+00		0.00E+00

Footnotes and Sources:

[a] Pacsi, Adam, et al., *Equipment Leak Detection and Quantification at 67 Oil and Gas Sites in the Western United States*, Elementa: Science of the Anthropocene (2019) 7:29. https://doi.org/10.1525/elementa.368.

[b] Gas content taken from GHGI Annex 3.6 Table 3.6-3 for U.S. Production segment Methane Content in Natural Gas by NEMS Region (General Sources). For the lower 48 states, in 2017, methane content at 81.6 mol%. The CH_4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH_4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

[c] Methane emission factors converted from whole gas are based on 60F and 14.7 psia.

[d] Study reported the emission factor as zero for these components.

Table 7-18 includes population average emission factors by service type from a 2017 field study on Upstream Oil and Gas components in Alberta, Canada.

Table 7-18. Population Average Equipment Leak Emission Factors in Alberta, Canada, Upstream Oil and Gas

Component	Original Emission Factor, kg THC/comp/hr [a, b]	Methane Content (mole %) [c]	Converted Methane Emission Factor, tonne CH_4/comp/hr	Uncertainty (± %)	Converted Emission Factor, scf gas/comp/hr
Service Type – Process Gas Service					
Connector	1.40E-04	81.6	4.15E-08	53	2.66E-03
Control valve	4.87E-03		1.45E-06	77	9.26E-02
Meter	1.05E-03		3.12E-07	73	2.00E-02
OEL	6.70E-02		1.99E-05	219	1.27E+00
PRV	3.99E-03		1.18E-06	85	7.58E-02
Pump seal	7.61E-03		2.26E-06	142	1.45E-01
Regulator	1.12E-03		3.32E-07	99	2.13E-02
Thief hatch	1.29E-01		3.82E-05	134	2.45E+00
Valve	4.40E-04		1.31E-07	112	8.36E-03
Service Type – Light Liquid Service					
Connector	1.00E-05	81.6	2.97E-09	114	1.90E-04
Valve	1.50E-04		4.45E-08	122	2.85E-03

Footnotes and Sources:

[a] Clearstone Engineering Ltd. *Technical Report – Update of Equipment, Component and Fugitive Emission Factors for Alberta Upstream Oil and Gas*. 10 June 2018.

[b] Emission factors presented on a volume basis are based on standard reference conditions of 101.325 kPa and 15°C.

[c] Gas content taken from GHGI Annex 3.6 Table 3.6-3 for U.S. Production segment Methane Content in Natural Gas by NEMS Region (General Sources). For the lower 48 states, in 2017, methane content at 81.6 mol%. The CH_4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH_4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

Table 7-19 provides emission factors for components on wellheads in the Production sector. Note that this data are specific to California and only applicable for conventional natural gas (e.g., excludes gas produced from fracking) (Kuo, et al., 2015).

Table 7-19. Component-Level Emission Factors for Components on Production Wellheads in California, USA

Component	Original Methane Emission Factor, cf CH_4/comp/min [a]	Methane Content, [b] (mole %)	Converted Methane Emission Factor, tonne CH_4/comp/hr [c]	Uncertainty (± %)	Converted Whole Gas Emission Factor, scf gas/comp/hr
Flange	2.12E-04	81.6	2.41E-07	Not Specified	1.54E-02
Manual Valves	5.90E-05		6.70E-08		4.29E-03
Seals	5.93E-04		6.74E-07		4.31E-02
Threaded Connection	6.25E-05		7.10E-08		4.55E-03

Footnotes and Sources:

[a] Jeff Kuo, Travis Hicks, Brian Drake, Tat Fu Chan (2015) *Estimation of Methane Emission from California Natural Gas Industry*, Journal of Air and Waste Management Association, 65:7, 844-855, DOI: 10.1080/10962247.2015.1025924.

[b] Gas content taken from GHGI Annex 3.6 Table 3.6-3 for U.S. Production segment Methane Content in Natural Gas by NEMS Region (General Sources). For the lower 48 states, in 2017, methane content at 81.6 mol%. The CH_4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH_4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

[c] 1 cubic foot of methane/minute = 1.136 kg methane/hr (Kuo, Jeff, et al., 2015).

Table 7-20 provides a summary of emission factors applicable to the Natural Gas Production and Natural Gas Processing sectors. The Natural Gas Processing sector information can be found in Section 7.3.1. Table 7-20 includes methane emission factors based on each component's respective equipment, which includes dehydrators, separators, piping segments, reciprocating compressors, and centrifugal compressors.

Table 7-20. Component-Level Emission Factors for Components on Production and Processing Equipment in California, USA

Component	Original Methane Emission Factor, tonne CH_4/comp/yr [a, b]	Methane Content, [c] (mole %)	Uncertainty (± %)	Converted Whole Gas Emission Factor, [d] scf gas/comp/hr
Equipment – Dehydrators				
Flange	1.58E-03	81.6	Not specified	1.16E-02
Regulators	6.28E-02			4.59E-01
Threaded Connection	2.44E-04			1.78E-03

Component	Original Methane Emission Factor, tonne CH_4/comp/yr [a, b]	Methane Content, [c] (mole %)	Uncertainty (± %)	Converted Whole Gas Emission Factor, [d] scf gas/comp/hr
Equipment – Separators				
Flange	1.55E-04	81.6	Not specified	1.13E-03
Manual Valves	2.61E-04			1.91E-03
Others	1.98E-01			1.45E+00
PRV	2.15E-03			1.57E-02
Regulators	2.71E-03			1.98E-02
Threaded Connection	6.02E-05			4.40E-04
Equipment – Piping Segments				
Flange	6.57E-05	81.6	Not specified	4.80E-04
Manual Valves	2.35E-04			1.72E-03
OEL	7.08E-03			5.18E-02
Others	4.90E-02			3.58E-01
Regulators	4.30E-03			3.14E-02
Threaded Connection	6.63E-04			4.85E-03
Equipment – Reciprocating Compressors				
Flange	9.49E-03	81.6	Not specified	6.94E-02
Manual Valves	1.49E-04			1.09E-03
OEL	6.63E-01			4.85E+00
Regulators	1.04E-03			7.60E-03
Threaded Connection	2.88E-04			2.11E-03
Equipment – Centrifugal Compressors				
Threaded Connection	9.33E-05	81.6	Not specified	6.82E-04

Footnotes and Sources:

[a] Jeff Kuo, Travis Hicks, Brian Drake, Tat Fu Chan (2015) *Estimation of Methane Emission from California Natural Gas Industry*, Journal of Air and Waste Management Association, 65:7, 844-855, DOI: 10.1080/10962247.2015.1025924.

[b] Only applicable for conventional natural gas, excludes natural gas produced from fracking.

[c] Gas content taken from GHGI Annex 3.6 Table 3.6-3 for U.S. Production segment Methane Content in Natural Gas by NEMS Region (General Sources). For the lower 48 states, in 2017, methane content at 81.6 mol%. The CH_4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH_4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

[d] Methane emission factors converted from whole gas are based on 60F and 14.7 psia.

If a facility implements a directed inspection and maintenance (DI&M) program to address and repair leaks, estimating emission reductions may be appropriate. The reduction potentials may vary based on the facility's size, age, type of equipment and operating conditions. Table 7-21 and Table 7-22 are applicable to those facilities that have implemented a DI&M program for upstream gas operations and oil operations, respectively. Similar to leak detection and repair programs (LDAR), the DI&M program is based on the reduction of equipment leak emissions through repairs of leaking components. The DI&M program, however, is a voluntary program based on cost-effective best practice for reducing methane emissions, whereas LDAR may involve strict regulations and potential penalties for non-compliance (CCAC, 2017). The emission factors presented in Tables 7-21 and 7-22 can be used for gas and oil operations, respectively, after the implementation of a DI&M program when more detailed data to utilize either leak/no-leak or correlation equation estimation approaches is not available.

Table 7-21. Emission Factors for Fugitive Equipment Leak Emissions after the Implementation of DI&M Program in Upstream Gas Segments

Component	Original Emission Factor, [a] scf THC/ comp/hr	Methane Content, [b] (mole %)	Converted Methane Emission Factor, tonne CH_4/comp/hr	Uncertainty (± %)	Converted Whole Gas Emission Factor, scf gas/comp/hr [b, c, d]
Service Type - All					
Open-Ended Line	1.83	81.6	2.86E-05	Not specified	1.83
Pressure Relief Valve	0.01		1.56E-07		0.01
Pump Seal	0.11		1.72E-06		0.11
Regulator	1.51		2.36E-05		1.51
Service Type - Gas/Vapor					
Compressor Seals	41.97	81.6	6.55E-04	Not specified	41.97
Connector	0.03		4.68E-07		0.03
Control Valve	1.57		2.45E-05		1.57
Valve	0.02		3.12E-07		0.02
Service Type - Light Liquid					
Connector	0.01	81.6	1.56E-07	Not specified	0.01
Valve	0.03		4.68E-07		0.03

Footnotes and Sources:

[a] CCAC O&G Methane Partnership – Technical Guidance Document Number 2: Fugitive Component and Equipment Leaks. Climate & Clean Air Coalition. March 2017.

[b] Gas content taken from GHGI Annex 3.6 Table 3.6-3 for U.S. Production segment Methane Content in Natural Gas by NEMS Region (General Sources). For the lower 48 states, in 2017, methane content at 81.6 mol%. The CH_4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH_4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

[c] Methane emission factors converted from whole gas are based on 60F and 14.7 psia.

[d] Whole gas emission factor conversion assumes that the gas released comprises 100% (mol or vol) of hydrocarbon; no CO2 present in the gas composition.

Table 7-22. Emission Factors for Fugitive Equipment Leak Emissions after the Implementation of DI&M Program in Upstream Oil Segments

Component	Original Emission Factor, scf THC/comp/hr [a]	Methane Content (mole %) [b]	Converted Methane Emission Factor, tonne CH_4/comp/hr	Uncertainty (± %)	Converted Whole Gas Emission Factor, scf gas/comp/hr [c, d]
Service Type – All					
Open-Ended Line	6.15	81.6	9.60E-05	Not specified	6.15
Pressure Relief Valve	0.01		1.56E-07		0.01
Pump Seal	0.09		1.41E-06		0.09
Regulator	20.72		3.24E-04		20.72
Service Type-Gas Vapor					
Compressor Seals	0.58	81.6	9.06E-06	Not specified	0.58
Connector	0.02		3.12E-07		0.02
Control Valve	3.55		5.54E-05		3.55
Valve	0.05		7.81E-07		0.05
Service Type – Light Liquid					
Connector	0.01	81.6	1.56E-07	Not specified	0.01
Valve	0.02		3.12E-07		0.02

Footnotes and Sources:

[a] CCAC O&G Methane Partnership – Technical Guidance Document Number 2: Fugitive Component and Equipment Leaks. Climate & Clean Air Coalition. March 2017.

[b] Gas content taken from GHGI Annex 3.6 Table 3.6-3 for U.S. Production segment Methane Content in Natural Gas by NEMS Region (General Sources). For the lower 48 states, in 2017, methane content at 81.6 mol%. The CH_4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

[c] Methane emission factors converted from whole gas are based on 60F and 14.7 psia.

[d] Whole gas emission factor conversion assumes that the gas released comprises 100% (mol or vol) of hydrocarbon; no inerts present in the gas composition.

An example calculation illustrating the use of the component-level fugitive equipment leak emission factors is provided in Exhibit 7-2.

7.2.2.4 Component Level - Leaker Factors

Leaker factors are used to estimate emissions from facilities using OGI or other leak screening approaches, such as EPA Method 21, to evaluate for leaks. Using this approach, the facility only needs to know the number of leaks by component type. Emission factors for onshore production are presented in Table 7-16 and were obtained from 40 CFR 98, Subpart W, "Mandatory Greenhouse Gas Reporting – Petroleum and Natural Gas Systems."

EPA provides equations in Subpart W to estimate volumetric emissions for a given component type and number of leaking components:

$$E_{A,v} = EF_A \times NL_A \times GHG_i \qquad \text{(Equation 7-9)}$$

where

$E_{A,v}$ = volumetric emission rate of GHG_i from component type A (scf/hr);

EF_A = leaker emission factor for the component type A from the applicable tables (scf/hr/component); and

NL_A = number of leaking component type A (components); and

GHG_i = concentration of GHG_i, CH_4, or CO_2

Using Equation 7-9, and converting to mass units using Equation 6-2, facilities can calculate the mass emission rate of CH_4 and CO_2 using the emission factors presented in the tables below. Please note that heavy crude is designated as having an API gravity of less than 20°C and light crude as having an API gravity of greater than 20°C.

Table 7-23 contains whole gas leaker emission factors that can be used if surveys have been completed based on GHGRP Subpart W 40 CFR §98.234(a)(1)-(6), including leak screening using OGI cameras and Method 21 surveys conducted at a leak threshold of 10,000 ppmv. These emission factors are applicable to the onshore petroleum and natural gas production as well as onshore petroleum and natural gas gathering and boosting sectors (GHGRP, 2019).

Table 7-23. Default Whole Gas Leaker Emission Factors; Surveys using 40 CFR §98.234(a)(1)-(6)

Component	Original Emission Factor, scf gas/comp/hr [a, b]	Methane Content (mole %) [c]	Converted Methane Emission Factor, tonne CH_4/comp/hr [d]	Uncertainty (± %)	Whole Gas Emission Factor, scf gas/comp/hr
Service Type – Gas Service					
Valve	4.9	81.6	7.7E-05	Not specified	4.9
Flange	4.1		6.4E-05		4.1
Connector (other)	1.3		2.0E-05		1.3
Open-Ended Line [e]	2.8		4.4E-05		2.8
Pressure Relief Valve	4.5		7.0E-05		4.5
Pump Seal	3.7		5.8E-05		3.7
Other [f]	4.5		7.0E-05		4.5
Service Type – Light Crude Service					
Valve	3.2	81.6	5.0E-05	Not specified	3.2
Flange	2.7		4.2E-05		2.7
Connector (other)	1		1.6E-05		1
Open-Ended Line [e]	1.6		2.5E-05		1.6
Pressure Relief Valve	3.7		5.8E-05		3.7
Pump Seal	3.7		5.8E-05		3.7
Other [f]	3.1		4.8E-05		3.1
Service Type – Heavy Crude Service					
Valve	3.2	81.6	5.0E-05	Not specified	3.2
Flange	2.7		4.2E-05		2.7
Connector (other)	1		1.6E-05		1
Open-Ended Line [e]	1.6		2.5E-05		1.6
Pressure Relief Valve	3.7		5.8E-05		3.7
Pump Seal	3.7		5.8E-05		3.7
Other [f]	3.1		4.8E-05		3.1

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (USEPA), 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Data reported as of August 2, 2019. Table W-1E. https://ecfr.io/Title-40/sp40.23.98.w.

[b] For multi-phase flow that includes gas, use gas service emission factors (GHGRP, 2019).

[c] Gas content taken from GHGI Annex 3.6 Table 3.6-3 for U.S. Production segment Methane Content in Natural Gas by NEMS Region (General Sources). For the lower 48 states, in 2017, methane content at 81.6 mol%. The CH_4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

[d] Methane emission factors converted from whole gas are based on 60°F and 14.7 psia.

[e] The open-ended lines component type includes blowdown valve and isolation valve leaks emitted through the blowdown vent stack for centrifugal and reciprocating compressors.

[f] "Others" category includes any equipment leak emission point not specifically listed in this table, as specified in 40 CFR §98.232(c)(21) and (j)(10).

Table 7-24 contains whole gas leaker emission factors that can be used if surveys have been completed based on Method 21 with a leak detection threshold of 500 ppmv as specified in 40 CFR §98.234(a)(7) of the GHGRP, in the onshore petroleum and natural gas production as well as onshore petroleum and natural gas gathering and boosting sectors (EPA, 2019).

Table 7-24. Default Whole Gas Leaker Emission Factors; Method 21 Surveys at 500 ppmv Leak Detection Threshold

Component	Original Emission Factor, [a, b] scf gas/comp/hr	Methane Content (mole %) [c]	Converted Methane Emission Factor, tonne CH_4/ comp/hr [d]	Uncertainty (± %)	Whole Gas Emission Factor, scf gas/comp/hr
Service Type – Gas Service					
Valve	3.5	81.6	5.5E-05	Not specified	3.5
Flange	2.2		3.4E-05		2.2
Connector (other)	0.8		1.2E-05		0.8
Open-Ended Line [e]	1.9		3.0E-05		1.9
Pressure Relief Valve	2.8		4.4E-05		2.8
Pump Seal	1.4		2.2E-05		1.4
Other [f]	2.8		4.4E-05		2.8
Service Type – Light Crude Service					
Valve	2.2	81.6	3.4E-05	Not specified	2.2
Flange	1.4		2.2E-05		1.4
Connector (other)	0.6		9.4E-06		0.6
Open-Ended Line [e]	1.1		1.7E-05		1.1
Pressure Relief Valve	2.6		4.1E-05		2.6
Pump Seal	2.6		4.1E-05		2.6
Other [f]	2.0		3.1E-05		2.0
Service Type – Heavy Crude Service					
Valve	2.2	81.6	3.4E-05	Not specified	2.2
Flange	1.4		2.2E-05		1.4
Connector (other)	0.6		9.4E-06		0.6
Open-Ended Line [e]	1.1		1.7E-05		1.1
Pressure Relief Valve	2.6		4.1E-05		2.6
Pump Seal	2.6		4.1E-05		2.6
Other [f]	2.0		3.1E-05		2.0

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (USEPA), 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Data reported as of August 2, 2019. Table W-1E. https://ecfr.io/Title-40/sp40.23.98.w. Emission factors are based on GHGRP 40 CFR §98.234(a)(7) using Method 21 surveys at a leak detection threshold of 500 ppmv.

[b] For multi-phase flow that includes gas, use gas service emission factors (GHGRP, 2019).

[c] Gas content taken from GHGI Annex 3.6 Table 3.6-3 for U.S. Production segment Methane Content in Natural Gas by NEMS Region (General Sources). For the lower 48 states, in 2017, methane content at 81.6 mol%. The CH_4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

[d] Methane emission factors converted from whole gas are based on 60°F and 14.7 psia.

[e] The open-ended lines component type includes blowdown valve and isolation valve leaks emitted through the blowdown vent stack for centrifugal and reciprocating compressors.

[f] "Others" category includes any equipment leak emission point not specifically listed in this table, as specified in 40 CFR §98.232(c)(21) and (j)(10).

Table 7-25 contains service specific leaker emission factors conducted at Canadian upstream oil and gas sites using OGI screening to determine leaks. Leaks were measured using a high-flow sampler. Non-leak emission factors were not determined as part of this study due to sensitivity constraints on the high-flow sampler (Clearstone Engineering Ltd., 2018). Note that the Clearstone Engineering Ltd. Technical Report defines light liquid as hydrocarbon liquid that has a vapor pressure of 0.3 kPa or greater at 15°C (includes light/medium crude oil, condensate, and NGLs), and process gas as process fluid that is hydrocarbon gas at specified operating conditions (Clearstone Engineering Ltd., 2018).

Table 7-25. Canadian Leaker Emission Factors for Upstream Oil and Gas Sites

Component	Original Emission Factor, [a, b, c] sm^3 THC/comp/hr	Methane Content, [d] (mole %)	Converted Emission Factor, tonne CH_4/comp/hr [e]	Uncertainty (± %) [f, g]	Converted Whole Gas Emission Factor, scf gas/comp/hr [e, h]
Service Type – Process Gas					
Compressor rod packing [i]	0.77563	81.6	4.2848E-04	56	27.44
Connector	0.10137		5.6000E-05	21	3.59
Control valve	0.12203		6.7413E-05	52	4.32
Meter	0.05238		2.8936E-05	50	1.85
OEL	0.70729		3.9073E-04	199	25.03
PRV	0.50395		2.7840E-04	63	17.83
Pump seal	0.16974		9.3769E-05	125	6.01
Regulator	0.09514		5.2558E-05	79	3.37
Thief hatch	0.82401		4.5521E-04	106	29.16
Valve	0.24356		1.3455E-04	97	8.62
SCVF [j]	3.74007		2.0661E-03	189	132.33
Service Type – Light Liquid					
Connector	0.04156	81.6	2.2959E-05	85	1.47
Valve	0.16929		9.3520E-05	110	5.99

Footnotes and Sources:

[a] Clearstone Engineering Ltd. *Technical Report – Update of Equipment, Component and Fugitive Emission Factors for Alberta Upstream Oil and Gas*. 10 June 2018.

[b] Emission factors presented on a volume basis are based on standard reference conditions of 101.325 kPa and 15°C.

[c] Emission factors from cited document were also presented in kg THC/hr/source.

[d] Gas content taken from GHGI Annex 3.6 Table 3.6-3 for U.S. Production segment Methane Content in Natural Gas by NEMS Region (General Sources). For the lower 48 states, in 2017, methane content at 81.6 mol%. The CH_4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

[e] THC emission factors converted to tonne CH4 and whole gas are based on 60F and 14.7 psia.

[f] Based on 95% confidence interval.

[g] Original emission factors were presented with upper and lower confidence limits. To be conservative, the larger % was chosen to represent the full % uncertainty of the mean value.

[h] Whole gas emission factor conversion assumes that the gas released comprises 100% (mol or vol) of hydrocarbon; no CO_2 present in the gas composition.

[i] Because reciprocating compressor rod-packing leakage is routed to common vent lines, the actual leaker count is unknown. The compressor rod-packing leaker factor is calculated on a per vent line basis, not a per rod-packing basis.

[j] Well surface casing vent flow.

7.2.2.5 Component Level - Screening Range Factor

The screening range factor approach, also called the leak/no-leak approach, is based on monitoring data that have been categorized into two or more ranges. Monitoring data are broken into categories of "leakers", with U.S. EPA Reference Method 21 readings greater than or equal to 10,000 ppmv, and "non-leakers" with readings less than 10,000 ppmv for the publications referenced herein. Equations utilized for this approach are detailed in Section 7.1.2.1.

Table 7-26 presents screening emission factors for onshore production by service type published by EPA (EPA, 1995). Service categories included in Table 7-26 are gas, light liquid or heavy liquid service. As previously stated, liquid services are defined differently by EPA (EPA, 1995) and API (API, 1995).

Table 7-26. EPA Onshore Oil and Natural Gas Production Equipment Leak Screening Emission Factors

Component – Service	**Original Emission Factor, kg TOC/comp/hr [a, b]**		**Converted Emission Factor, tonne TOC/comp/hr**		**Uncertainty (±)**
	< 10,000 ppmv	**≥ 10,000 ppmv**	**< 10,000 ppmv**	**≥ 10,000 ppmv**	
Valves – Gas	2.5E-05	9.8E-02	2.5E-08	9.8E-05	Not Specified
Valves – Light Oil [c]	1.9E-05	8.7E-02	1.9E-08	8.7E-05	
Valves – Water/Oil	9.7E-06	6.4E-02	9.7E-09	6.4E-05	
Valves – Heavy Oil [c]	8.4E-06	NA	8.4E-09	NA	
Pump Seals – Gas	3.5E-04	7.4E-02	3.5E-07	7.4E-05	
Pump Seals – Light Oil [c]	5.1E-04	1.0E-01	5.1E-07	1.0E-04	
Pump Seals – Water/Oil	2.4E-05	NA	2.4E-08	NA	
Others – Gas	1.2E-04	8.9E-02	1.2E-07	8.9E-05	
Others – Light Oil [c]	1.1E-04	8.3E-02	1.1E-07	8.3E-05	
Others – Water/Oil	5.9E-05	6.9E-02	5.9E-08	6.9E-05	
Others – Heavy Oil [c]	3.2E-05	NA	3.2E-08	NA	
Connectors – Gas	1.0E-05	2.6E-02	1.0E-08	2.6E-05	
Connectors – Light Oil [c]	9.7E-06	2.6E-02	9.7E-09	2.6E-05	
Connectors – Water/Oil	1.0E-05	2.8E-02	1.0E-08	2.8E-05	
Connectors – Heavy Oil [c]	7.5E-06	NA	7.5E-09	NA	

Component – Service	**Original Emission Factor, kg TOC/comp/hr [a, b]**		**Converted Emission Factor, tonne TOC/comp/hr**		**Uncertainty (±)**
	< 10,000 ppmv	**≥ 10,000 ppmv**	**< 10,000 ppmv**	**≥ 10,000 ppmv**	
Flanges – Gas	5.7E-06	8.2E-02	5.7E-09	8.2E-05	
Flanges – Light Oil [c]	2.4E-06	7.3E-02	2.4E-09	7.3E-05	
Flanges – Heavy Oil [c]	3.9E-07	NA	3.9E-10	NA	
Flanges – Water/Oil	2.9E-06	NA	2.9E-09	NA	
Open-ended Line – Gas	1.5E-05	5.5E-02	1.5E-08	5.5E-05	
Open-ended Line – Heavy Oil [c]	7.2E-06	3.0E-02	7.2E-09	3.0E-05	
Open-ended Line – Light Oil [c]	1.4E-05	4.4E-02	1.4E-08	4.4E-05	
Open-ended Line – Water/Oil	3.5E-06	3.0E-02	3.5E-09	3.0E-05	

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (EPA). Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017, EPA Office of Air Quality Planning and Standards, November 1995, Table 2-8.

[b] NA means that there were not sufficient examples of that emission category found to develop an emission factor.

[c] EPA defines light liquids as liquids for which the sum of the concentration of individual constituents with a vapor pressure over 0.3 kPa at 20°C is greater than or equal to 20 weight percent. EPA defines heavy liquids as liquids not in gas/vapor or light liquid service.

Table 7-27 presents screening emission factors for onshore production based on production facility emission factors from API Publication No. 4615 Emission Factors for Oil and Gas Production Operations, which include service type. Table 7-27 also includes emission factors applicable to all sectors, for reference.

Table 7-27. API Onshore Oil and Natural Gas Production Equipment Leak Screening Emission Factors

Component – Service Type [c]	**Emission Factor, Original Units, [a, b] lb TOC/comp/day**		**Emission Factor, Converted to Tonne, tonne TOC/ comp/hr**		**Uncertainty (±)**
	< 10,000 ppmV	**≥ 10,000 ppmV**	**< 10,000 ppmV**	**≥ 10,000 ppmV**	
Facility Type – All Segments [f]					
Valves – All Service	NA	3.381	NA	6.39E-05	Not Specified
Connectors – All Service	NA	1.497	NA	2.83E-05	
Flanges – All Service	NA	4.490	NA	8.49E-05	
Open-ended Lines – All Service	NA	1.600	NA	3.02E-05	
Pump Seals – All Service	NA	3.905	NA	7.38E-05	
Others – All Service	NA	3.846	NA	7.27E-05	
Facility Type – Production					
Valves – Gas	1.63E-03	3.381	6.39E-05	6.39E-05	Not Specified
Valves – Light Crude	1.11E-03	3.381	2.83E-05	6.39E-05	
Valves – Heavy Crude	6.95E-04	3.381	8.49E-05	6.39E-05	
Connectors – Gas	6.33E-04	1.497	3.02E-05	2.83E-05	
Connectors – Light Crude	5.25E-04	1.497	7.38E-05	2.83E-05	
Connectors – Heavy Crude	4.41E-04	1.497	7.27E-05	2.83E-05	
Flanges – Gas	1.30E-03	4.49	6.39E-05	8.49E-05	
Flanges – Light Crude	1.24E-03	4.49	2.83E-05	8.49E-05	
Flanges – Heavy Crude	1.19E-03	4.49	8.49E-05	8.49E-05	
Open-ended Lines – Gas	1.26E-03	1.6	3.02E-05	3.02E-05	
Open-ended Lines – Light Crude	1.50E-03	1.6	7.38E-05	3.02E-05	
Open-ended Lines – Heavy Crude	8.86E-04	1.6	7.27E-05	3.02E-05	
Pump Seals – Gas	1.03E-02	3.905	6.39E-05	7.38E-05	

Component – Service Type [c]	**Emission Factor, Original Units, [a, b] lb TOC/comp/day**		**Emission Factor, Converted to Tonne, tonne TOC/ comp/hr**		**Uncertainty (±)**
	< 10,000 ppmV	**≥ 10,000 ppmV**	**< 10,000 ppmV**	**≥ 10,000 ppmV**	
Pump Seals – Heavy Crude	No data	3.905	2.83E-05	7.38E-05	
Pump Seals – Light Crude	1.68E-02	3.905	8.49E-05	7.38E-05	
Others – Gas	7.92E-03	3.846	3.02E-05	7.27E-05	
Others – Heavy Crude	3.67E-03	3.846	7.38E-05	7.27E-05	
Others – Light Crude	9.01E-03	3.846	7.27E-05	7.27E-05	

Footnotes and Sources:

[a] American Petroleum Institute (API). *Emission Factors for Oil and Gas Production Operations*, API Publications No. 4615, Health and Environmental Services Department, January 1995, Table ES-2.

[b] NA means not available on the "all facilities" basis. The emission factors for leaking components were developed as a single factor across all facility types. The emission factors for non-leaking components, however, were developed for each facility type.

[c] These emission factors are facility specific, not service specific. For example, a facility producing light crude would apply the light crude production emission factors regardless of the service type. API Publication 4615 defines light crude as oil with an API gravity of 20 or more, and heavy crude as oil with an API gravity of less than 20.

[d] Gas content taken from GHGI Annex 3.6 Table 3.6-3 for U.S. Production segment Methane Content in Natural Gas by NEMS Region (General Sources). For the lower 48 states, in 2017, methane content at 81.6 mol%. The CH_4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

[e] To convert from total organic compound (TOC) mass emissions to methane and whole gas, it is assumed that the gas stream contains 100% total organic compounds; i.e., no inerts present in the gas composition. The average molecular weight of the TOC stream is assumed "as propane" at 44 lb/lb-mol.

[f] Average emission factors across all segments of industry.

The Climate and Clean Air Coalition's Technical Document No. 2 on equipment leaks provides alternative leak/no-leak emission factors that can be applied if leaks have been detected using OGI, as shown in Table 7-28 below. Emission factors are provided for both leak and no-leak screening data for several leak definitions of the instrument used (if no information are available, the higher leak definition – 60 g/hr, should be used). Note that these emission factors are general, and have no specified applicable sector (CCAC, 2017).

Table 7-28. Alternative Leak/No-Leak Emission Factors for use with OGI Technologies

Component	Original Emission Factor in g CH_4/comp/hr [a]			
	Specified Leak Definition – 3 g/hr [b]	Specified Leak Definition – 6 g/hr [b]	Specified Leak Definition – 30 g/hr [b]	Specified Leak Definition – 60 g/hr [b]
Emission Factor Type – No-Leak				
Valves	0.019	0.043	0.17	0.27
Pumps, Compressors	0.096	0.13	0.59	0.75
Flanges	0.0026	0.0041	0.01	0.014
Other components	0.007	0.014	0.051	0.081
Emission Factor Type – Leak				
Valves	55	73	140	200
Pumps, Compressors	140	160	310	350
Flanges	29	45	88	120
Other components	56	75	150	210

Footnotes and Sources:

[a] CCAC O&G Methane Partnership – Technical Guidance Document Number 2: Fugitive Component and Equipment Leaks. Climate & Clean Air Coalition. March 2017.

[b] Grams per hour based on the U.S. EPA definition of a "leak" being greater than 10,000 ppm by OVA. Non-leak factors are averages of measured leaks less than 10,000 ppm. If a leak can be seen with a gas imaging camera, it should be quantified with leak factor (CCAC, 2017).

Where plant-specific stream composition data are not available, the composition data should be taken from Table C-2 (presented in Appendix C, Section C.1.1) and applied to the stream service specific emission factors in Table 7-26 and Table 7-27. When emission factors from

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Table 7-28 are applied, the CH_4 composition from Table C-1 (presented in Appendix C, Section C.1.1) is used since these are based on an aggregated stream composition for the facility.

7.2.2.6 Correlation Equations Using Method 21 Monitoring

The correlation approach predicts the mass emission rate as a function of the screening value for a particular component type as detailed in Section 7.1.2.2. If Method 21 monitoring data (i.e., screening values) are available, please refer to Section 7.3 for details regarding the methodological approach and the applicable correlation equations.

7.2.3 Gathering and Boosting Operations

7.2.3.1 Facility Level

For the gathering and boosting segment, in the absence of data on equipment or components, an average facility-level emission factor approach can be used as the simplest though least accurate method for estimating CH_4 emissions from fugitive equipment leaks. The following emission factor, based on a measurement study at 180 facilities in the US, can be used to estimate emissions at the facility level for oil and gas gathering and boosting stations (Zimmerle, 2020).

1.35 kg CH_4/station/hr (Original Units) [a, b]
0.00135 tonne CH_4/station/hr (Converted)
86.5 scf gas/station/hr (Converted) [c, d]

Footnotes and Sources:

[a] Zimmerle, Daniel, et al., Methane Emissions from Gathering Compressor Stations in the US. Environmental Science & Technology. 14 May 2020. https://dx.doi.org/10.1021/acs.est.0c00516.

[b] Uncertainty for the original value is ± 41%.

[c] Gas content taken from GHGI Annex 3.6 Table 3.6-3 for U.S. Production segment Methane Content in Natural Gas by NEMS Region (General Sources). For the lower 48 states, in 2017, methane content at 81.6 mol%. The CH_4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

[d] Methane emission factors converted to whole gas are based on 60°F and 14.7 psia.

7.2.3.2 Equipment Level

The equipment-level average emission factor approach can be used for estimating fugitive equipment leaks emissions for a particular gathering and boosting facility based on the population of major equipment at the facility. The method for estimating fugitive equipment leaks emissions using the major equipment approach is discussed in Section 7.2.2.2. See Equation 7-1 to quantify emissions using the major equipment-level approach.

The whole gas pipeline population emission factors in Table 7-10 of Section 7.2.2.2 are applicable to this section as they apply to onshore petroleum and natural gas gathering and boosting, as well as to production.

In addition, the following emission factor from GHGI provides an estimate for gathering and boosting pipeline leaks in natural gas systems (EPA GHGI, 2019).

347.6 kg CH_4/mile/yr (Original Units) [a, b]
3.968E-05 tonne CH_4/mile/hr (Converted) [c]
2.542 scf gas/mile/hr (Converted) [c, d, e]

Footnotes and Sources:

[a] EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 – 2017. 2019. These values were calculated using 2017 year-specific GHGRP Subpart W data by region. Note: These factors, used in the USEPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017 (EPA 2019), are updated annually based on data reported from operators under the GHGRP.

[b] Uncertainty for the original value is not specified.

[c] Conversion assumes 8,760 hours of annual operation.

[d] Gas content taken from GHGI Annex 3.6 Table 3.6-3 for U.S. Production segment Methane Content in Natural Gas by NEMS Region (General Sources). For the lower 48 states, in 2017, methane content at 81.6 mol%. The CH_4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

[e] Methane emission factors converted to whole gas are based on 60 F and 14.7 psia.

Table 7-29 below includes emission factors for gathering and boosting station fugitive emissions at the equipment level, and are based on measurements across 180 facilities in the US (Zimmerle, 2020). *It should be noted that these equipment-level emission factors also include venting from natural gas-operated pneumatic devices; therefore, if these factors are used to quantify fugitive equipment leak emissions, no additional estimation of pneumatic controller venting should be included to avoid double counting.*

Table 7-29. Equipment-Level Emission Factors for Equipment Leaks from Gathering and Boosting

Component	Original Methane Emission Factor, [a, b] kg CH_4/unit/hr	Methane Content, [c] (mole %)	Converted Methane Emission Factor, [c] tonne CH_4/unit/hr	Uncertainty, [d] (± %)	Converted Whole Gas Emission Factor, [c, e] scf gas/unit/hr
AGRU [f]	0.0683	81.6	6.83E-05	46	4.37
Compressor	1.84		1.84E-03	14	118
Dehydrator	0.0569		5.69E-05	13	3.64
Separator	0.0105		1.05E-05	12	0.67
Tanks	0.64		6.4E-04	9.9	41

Footnotes and Sources:

[a] Zimmerle, Daniel, et al., *Methane Emissions from Gathering Compressor Stations in the US*. Environmental Science & Technology. 14 May 2020. https://dx.doi.org/10.1021/acs.est.0c00516.

[b] These emission factors may include both fugitive and vented sources, such as natural gas-operated pneumatic controllers and compressor rod packing vents.

[c] Gas content taken from GHGI Annex 3.6 Table 3.6-3 for U.S. Production segment Methane Content in Natural Gas by NEMS Region (General Sources). For the lower 48 states, in 2017, methane content at 81.6 mol%. The CH_4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

[d] Uncertainty is based on 95% confidence interval, and represents the larger of the upper and lower confidence limit reported.

[e] Methane emission factors converted to whole gas are based on 60 F and 14.7 psia.

[f] Emission factor is based upon few measurements and is unlikely to be robust (Zimmerle, 2020).

For an example of calculating CH_4 emissions using the major equipment emission factor approach, see Exhibit 7-3 in Section 7.2.2.2.

7.2.3.3 Component Level – Average Emission Factor

For fugitive equipment leak estimates from gathering and boosting facilities where only component count data are available, the component-level average emission factor approach can be used to provide a more accurate estimate than equipment- or facility-level emission factor approaches. If component count information is not available, generic counts can be obtained as detailed in Appendix C, Section C.1.2.

Certain emission factors contained in the onshore production section are applicable to gathering and boosting. Whole gas emission factors applicable to onshore petroleum and natural gas gathering and boosting by service type and location can be found in Table 7-16 in Section 7.2.2.3. Table 7-17 also provides whole gas emission factors applicable to onshore petroleum and natural gas gathering and boosting by service type, and is specific to the Western United States. Note that this study does not claim national representativeness and therefore should not be used for components outside of the Western United States (Pacsi, 2019). Table 7-18 includes population average emission factors by service type applicable to upstream oil and gas components, from a 2017 field study done in Alberta, Canada. If the facility has implemented a directed inspection and maintenance (DI&M) program to address and repair leaks, the facility can use the emission factors in Table 7-21 and Table 7-22.

Table 7-30 presents natural gas plant, gathering compressor station, and well site average THC emissions factors based on a comprehensive measurement program, conducted to determine cost-effective directed inspection and maintenance (DI&M) control opportunities (EPA, 2006). This report presents fugitive equipment leak emission factors from two phases of site measurements. Phase I of the program was conducted at four gas processing plants in the Western U.S. during 2000. Phase II of the program was conducted at five gas processing plants, seven gathering compressor stations, and 12 well sites during 2004 and 2005. Details on the methodologies and equations used to estimate TOC mass emissions for a given component type are included in Sections 7.1.1 and 7.2.1. Phase I study results were excluded from this section since they are not pertinent to the gathering and boosting sector.

Table 7-30. Natural Gas Plant, Gathering Compressor Stations, and Well Site Average Equipment Leak Emission Factors

Component	**Phase II (Gas Plants, Gathering Compressor Stations, and Well Sites) [a]**				
	Average Emission Factor [b], Original Units, kg THC/hr/source	**Methane Content (mole %) [c]**	**Average Emission Factor, Converted tonne CH_4/ hr/source [d]**	**Uncertainty, (± %)**	**Converted Whole Gas Emission Factor, scf gas/hr/source**
Connectors	3.30E-03	81.6	9.79E-07	Not specified	6.27E-02
Block Valves	1.47E-02		4.36E-06		2.79E-01
Control Valves	3.73E-02		1.11E-05		7.09E-01
Pressure Relief Valves (PRV)	4.70E-04		1.39E-07		8.93E-03
Pressure Regulators	6.31E-03		1.87E-06		1.20E-01

Component	Phase II (Gas Plants, Gathering Compressor Stations, and Well Sites) [a]				
	Average Emission Factor [b], Original Units, kg THC/hr/source	Methane Content (mole %) [c]	Average Emission Factor, Converted tonne CH_4/ hr/source [d]	Uncertainty, (± %)	Converted Whole Gas Emission Factor, scf gas/hr/source
Orifice Meters	2.70E-03		8.01E-07		5.13E-02
Crank Case Vents	1.20E-01		3.56E-05		2.28
Open-Ended Lines (OEL)	2.39E-01		7.09E-05		4.54
Compressor Seals [e]	5.20E-01		1.54E-04		9.88

Footnotes and Sources:

[a] Phase II of the study was based on surveys at five gas processing plants, seven gathering compressor stations, and 12 well sites during the first quarter of 2004 and second quarter of 2005. Table 3 of the above referenced report shows that the measured THC emission rates from the leaking components were 1,348 tonns/facility-yr for gas plants, 131 tonne/facility-yr for gathering compressor stations, and 8 tonne/facility-yr for well sites. Based on the counts of the facilities and measured leak rates, the measured leak rates were comprised of 86.9% from gas plants, 11.8% from gathering compressor stations, and 1.2% from well sites.

[b] U.S. Environmental Protection Agency (EPA). *EPA Phase II Aggregate Site Report: Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites, Technical Report*, prepared by National Gas Machinery Laboratory, Clearstone Engineering, Ltd., and Innovative Environmental Solutions, Inc., March 2006, Table 4.

[c] Gas content taken from GHGI Annex 3.6 Table 3.6-3 for U.S. Production segment Methane Content in Natural Gas by NEMS Region (General Sources). For the lower 48 states, in 2017, methane content at 81.6 mol%. The CH_4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

[d] To convert from total organic compound (TOC) mass emissions to methane and whole gas, it is assumed that the gas stream contains 100% total organic compounds; i.e., no inerts present in the gas composition. The average molecular weight of the TOC stream is assumed "as propane" at 44 lb/lb-mol.

[e] Compressor seals component category accounts for emissions from individual compressor seals. As compressor seal leakage was typically measured from common vent and drain lines, emissions have been divided evenly among the seals on units with detected leakage.

Table 7-31 below includes population emission factors for components in the gathering and boosting sector, with specifics involving the equipment associated with each component (Zimmerle, 2019).

Table 7-31. Population Equipment Leak Emission Factors for Components in Gathering and Boosting

Component	Original Methane Emission Factor, scf CH_4/unit/hr [a]	Methane Content, [b] (mole %)	Converted Methane Emission Factor, [c] tonne CH_4/unit/hr	Uncertainty, [d] (± %)	Converted Whole Gas Emission Factor, [e] scf gas/unit/hr
Equipment Type – Non-Compressor					
Connector (flanged)	0.014	81.6	2.7E-07	15	0.0168
Connector (threaded)	0.000898		1.72E-08	12	0.0104
PRV	0.236		4.52E-06	51	0.264
Regulators	0.427		8.17E-06	23	0.524
Valve	0.0697		1.33E-06	19	0.0811
Equipment Type – Compressor					
Connector (flanged)	0.0103	81.6	1.97E-07	19	0.0135
Connector (threaded)	0.0211		4.04E-07	31	0.0249
PRV	0.409		7.83E-06	48	0.474
Regulators	0.53		1.0E-05	13	0.668
Valve	0.138		2.64E-06	49	0.153
Common Single-Unit Vent [f]	3.24		6.20E-05	19	4.07
Blowdown Vent [f]	1.02		1.95E-05	77	1.36
Pocket Vent [g]	0.0925		1.77E-06	29	0.109
Rod Packing Vent [f]	25		4.8E-04	21	28.4
Equipment Type – Tank [h]					
Common Single-Unit Vent	8.25	81.6	1.58E-04	44	9.21
Thief hatch	8.77		1.68E-04	30	9.85

Component	Original Methane Emission Factor, scf CH_4/unit/hr [a]	Methane Content, [b] (mole %)	Converted Methane Emission Factor, [c] tonne CH_4/unit/hr	Uncertainty, [d] (± %)	Converted Whole Gas Emission Factor, [e] scf gas/unit/hr
Equipment Type - Other					
OEL	0.172	81.6	3.29E-06	31	0.209

Footnotes and Sources:

[a] Zimmerle, Daniel, et al., *Characterization of Methane Emissions from Gathering Compressor Stations: Final Report*. Energy Institute – Colorado State University. 2019.

[b] Gas content taken from GHGI Annex 3.6 Table 3.6-3 for U.S. Production segment Methane Content in Natural Gas by NEMS Region (General Sources). For the lower 48 states, in 2017, methane content at 81.6 mol%. The CH_4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

[c] Methane emission factors converted to tonne are based on 60°F and 14.7 psia.

[d] Uncertainty is based on 95% confidence interval, and represents the larger of the upper and lower confidence limit reported.

[e] These emission factors were also originally represented in the cited study.

[f] These emission factors represent activity basis where there exists one per compressor.

[g] These emission factors represent activity basis per compressor cylinders.

[h] These emission factors represent activity basis one per tank.

Exhibit 7-2 presents calculation methodologies for the average emission factor approach.

7.2.3.4 Component Level - Leaker Factors

For gathering and boosting stations that have conducted leak screening by OGI, the OGI leaker factors can be used to estimate fugitive emissions from equipment components. Using this approach, the facility only needs to know the number of leaks by component type and apply the OGI leaker factors.

Details on the methodologies and equations used to estimate mass emissions for a given component type are included in Section 7.2.2.4, and can be utilized for gathering and boosting operations.

Table 7-23 presents whole gas leaker emission factors that can be used if surveys have been completed using the methods described in the GHGRP Subpart W (40 CFR §98.234(a)(1)-(6)), which include leak screening using OGI cameras or Method 21 surveys conducted at a leak threshold of 10,000 ppmv. Table 7-24 presents whole gas leaker factors that can be used if leak surveys have been conducted using Method 21 with a leak threshold of 500 ppmv, as described in the GHGRP Subpart W (40 CFR §98.234(a)(7)).

Table 7-32 below includes leaker emission factors for components in the gathering and boosting sector, with specific factors for components associated with the compressor, which are subject to vibration and found to have higher leak rates, as reported separately from non-compressor related components (Zimmerle, 2019).

Table 7-32. Leaker Emission Factors for Components in Gathering and Boosting

Component	Original Methane Emission Factor, scf CH_4/unit/hr [a]	Methane Content (%) [b]	Converted Methane Emission Factor, tonne CH_4/unit/hr [c]	Uncertainty (± %) [d]	Converted Whole Gas Emission Factor, scf gas/unit/hr [e]
Equipment Type – Non-Compressor					
Connector (flanged)	5.21	81.6	9.97E-05	44	6.2
Connector (threaded)	4.08		7.81E-05	38	4.73
PRV	8.88		1.70E-04	131	9.98
Regulators	5.49		1.05E-04	39	6.7
Valve	5.99		1.15E-04	41	7.06
Equipment Type – Compressor					
Connector (flanged)	6.73	81.6	1.29E-04	53	8.77
Connector (threaded)	9.99		1.91E-04	56	11.9
PRV	15.9		3.04E-04	91	18.5
Regulators	9.42		1.80E-04	36	11.8
Valve	33.4		6.39E-04	123	36.9
Common multi-unit vent	50.7		9.70E-04	82	59.4
Common single-unit vent	49.6		9.49E-04	47	61.7
Blowdown vent	11.7		2.24E-04	148	16.1
Pocket vent	5.34		1.02E-04	81	6.32
Rod packing vent	23.4		4.48E-04	35	26.5
Starter vent	283		5.41E-03	187	287

Component	**Original Methane Emission Factor, scf CH_4/unit/hr** [a]	**Methane Content (%)** [b]	**Converted Methane Emission Factor, tonne CH_4/unit/hr** [c]	**Uncertainty (± %)** [d]	**Converted Whole Gas Emission Factor, scf gas/unit/hr** [e]
Equipment Type – Tank					
Common multi-unit vent	112	81.6	2.14E-03	100	120
Common single-unit vent	44.4		8.50E-04	93	48.8
Thief hatch	26.3		5.03E-04	66	29.9
Equipment Type – Other [f]					
Common station vent	73.9	81.6	1.41E-03	98	82.2
OEL	3.22		6.16E-05	68	3.94
Other	18.9		3.62E-04	83	21.7
Pump	22.6		4.32E-04	78	29.9

Footnotes and Sources:

[a] Zimmerle, Daniel, et al., *Characterization of Methane Emissions from Gathering Compressor Stations: Final Report*. Energy Institute – Colorado State University. 2019.

[b] Gas content taken from GHGI Annex 3.6 Table 3.6-3 for U.S. Production segment Methane Content in Natural Gas by NEMS Region (General Sources). For the lower 48 states, in 2017, methane content at 81.6 mol%. The CH_4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

[c] Methane emission factors converted to tonne are based on 60°F and 14.7 psia.

[d] Original emission factors were presented with upper and lower confidence intervals. To be conservative, the larger % was chosen to represent the full % uncertainty of the mean value.

[e] These emission factors were also originally represented in the cited study.

[f] This equipment type includes emission factors where there was insufficient data to develop separate factors for each service category. These factors may be utilized for any service type.

7.2.3.5 Component Level - Screening Range Factors

As previously discussed, the screening range factor approach, also called the leak/no-leak approach, is based on monitoring data that have been categorized into two or more ranges: leakers and non-leakers.

Equations utilized for this approach are detailed in Section 7.2.1.5. Table 7-7 provides leak / no leak emission factors for all facility types. In addition, Table 7-28 presented in Section 7.2.2.5 contains leak / no leak emission factors that are not segment specific that could be applied to gathering and boosting facilities.

Example calculations presented in Exhibit 7-3 can be utilized for gathering and boosting operations.

7.2.3.6 Correlation Equations Using Method 21 Monitoring

The correlation approach predicts the mass emission rate as a function of the screening value for a particular equipment type as detailed in Section 7.1.2.2.If Method 21 monitoring data (i.e., screening values) are available, please refer to Section 7.3 for detailed methodological approach and correlation equations.

7.3 Equipment Leaks Estimation – Midstream Operations

In midstream operations, methane emissions from equipment leaks can occur from valves, flanges, connectors, open-ended lines, and other components from facilities, pipelines, and other transport modes in the midstream segment. This section provides further details on the various methodologies, or approaches, as well as emission factors for calculating equipment leak emissions from the following operations:

- Natural gas processing and fractionation;
- Natural gas transmission and storage;
- CO_2 Transport;
- Natural gas distribution;
- Crude oil transport; and
- Liquefied natural gas (LNG) supply chain.

A summary of all the emission factor sets included for midstream oil and gas operations is provided in Table 7-33. As shown, the emission factor sets are organized by the type of operation and the equipment leak approach. This summary is intended to help guide the user in selection of the most appropriate emission factors for quantification of equipment leak emissions from midstream operations. The application of specific sets of emission factors will depend on the type of operation and the data available for quantifying equipment leak emissions.

7.3.1 Natural Gas Processing and Fractionation

7.3.1.1 Facility Level

As detailed in Section 7.1.1, applying average facility-level emission factors is the simplest method for estimating CH_4 emissions from oil and gas operations. Facility-level emission factors for Natural Gas Processing and Fractionation operations are presented in Table 7-34, including factors from the 1996 methane study (GRI, 1996) and US national inventory (EPA GHGI, 2019). Exhibit 7-1 demonstrates the use of facility-level average emission factors.

Table 7-33. Equipment Leaks Emission Factor Summary Table – Midstream Operations

Table	Table Title	Data Source(s)	Location	Year Published	Measurement Approach	Sample Size	Original Data Source
Section 7.3.1.1 Natural Gas Processing and Fractionation – Facility Level							
7-34	Facility-Level Average Fugitive Emission Factors for Natural Gas Plants	Campbell et al. 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. EPA	US	1996	GRI Hi-Flow ™ Sampler or EPA Protocol Method 21	For compressor components, results based on measurements at 15 compressor stations. For other components, 8 gas processing plants were measured using EPA Protocol approach.	Direct measurement study conducted in the early 1990s and published in 1996.
		EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 – 2017. 2019	US	2019	These values were calculated using 2017 year-specific GHGRP Subpart W data by region.		
7.3.1.2 Natural Gas Processing and Fractionation – Equipment Level							
7-35	Equipment-Level Methane Emission Factors for Natural Gas Processing Equipment	Campbell et al. 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. EPA	US	1996	GRI Hi-Flow ™ Sampler or EPA Protocol Method 21	For compressor components, results based on measurements at 15 compressor stations. For other components, 8 gas processing plants were measured using EPA Protocol approach.	Direct measurement study conducted in the early 1990s and published in 1996.
		Hummel, K.E., L.M. Campbell, and M.R. Harrison. Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Final Report, GRI-94/0257.25 and EPA-600/R-96-080h. Gas Research Institute and U.S. EPA, June 1996	US	1996	GRI Hi-Flow ™ Sampler or EPA Protocol Method 21	8 gas processing plants	Processing data from: Star Environmental, Fugitive Hydrocarbon Emissions from Oil and Gas Production Operations, API Publication Number 4589. API, 1993. Star Environmental, Emission Factors for Oil and Gas Production Operations, API Publication Number 4615, 1995. Compressor data from: Indaco Air Quality

Table	Table Title	Data Source(s)	Location	Year Published	Measurement Approach	Sample Size	Original Data Source
							Services INC. Leak Rate Measurements at U.S. Natural Gas Transmission Compressor Stations. Gas Research Institute, 1994. This data is referenced in USEPA GHGRP Regulatory Program.
		DOE, Natural Gas Annual	US	1993	Not applicable	Not applicable	Not applicable
7.3.1.3 Natural Gas Processing and Fractionation – Component Level Average Emission Factor							
7-36	Natural Gas Plant, Gathering Compressor Station, and Well Site Average Component-Level Emission Factors	EPA. EPA Phase II Aggregate Site Report: Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites, Technical Report, prepared by National Gas Machinery Laboratory, Clearstone Engineering, Ltd., and Innovative Environmental Solutions, Inc., March 2006.	US	2006	GRI Hi-Flow ™ Sampler	Phase I of the study was based on surveys at four gas processing facilities in the Western U.S. completed during the 4th quarter of 2000	This data is referenced in USEPA GHGRP Regulatory Program.
7-37	API Natural Gas Processing Plant Average Component-Level Emission Factors	API. Emission Factors for Oil and Gas Production Operations, API Publication No. 4615, Health and Environmental Sciences Department, January 1995.	US	1995	EPA Protocol Method 21	20 oil and gas production sites with data from 4 additional gas processing plant sites	Direct measurement study conducted in the early 1990s published in 1995.
7.3.1.4 Natural Gas Processing and Fractionation – Leaker Factors							
7-38	EPA 40 CFR 98 Subpart W Component-Level Leaker Emission Factors for Natural Gas Processing	EPA, 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Table W-2. Data reported as of August 2, 2019. https://ecfr.io/Title-40/sp40.23.98.w Part of EPA GHGRP Regulatory Program.	US	2019	Derived	Derived	EPA. Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants. Clearstone Engineering Ltd. June 20, 2002. National Gas Machinery Laboratory, Kansas State University; Clearstone Engineering, Ltd; Innovative Environmental Solutions, Inc. Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing

Table	Table Title	Data Source(s)	Location	Year Published	Measurement Approach	Sample Size	Original Data Source
							Plants and Upstream Gathering Compressor Stations and Well Sites. For EPA Natural Gas STAR Program. March 2006.
7.3.1.5 Natural Gas Processing and Fractionation – Component Level - Screening Range Factor							
7-39	API Natural Gas Processing Screening Factors	API. Emission Factors for Oil and Gas Production Operations, API Publication No. 4615, Health and Environmental Sciences Department, January 1995.	US	1995	EPA Protocol Method 21	20 oil and gas production sites with data from 4 additional gas processing plant sites	Direct measurement study conducted in the early 1990s published in 1995.
7.3.1.6 Natural Gas Processing and Fractionation –Correlation Equations Using Method 21 Monitoring							
7-40	Petroleum Industry Leak Rate/Screening Value (SV) Correlations	EPA. Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017, EPA Office of Air Quality Planning and Standards, November 1995, Table 2-10	US	1995	Derived	Derived from bagging data from 24 oil and gas production facilities	API. Emission Factors for Oil and Gas Production Operations, API Publication Number 4615, Health and Environmental Sciences Department, January 1995. API. Fugitive Hydrocarbon Emissions from Oil and Gas Production Operations, API 4589, Star Environmental, 1993. This data is referenced in USEPA GHGRP Regulatory Program.
7-41	Default Zero Values for the Petroleum Industry	EPA. Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017, EPA Office of Air Quality Planning and Standards, November 1995, Table 2-12	US	1995	Derived	Derived from bagging data from 24 oil and gas production facilities	API. Emission Factors for Oil and Gas Production Operations, API Publication Number 4615, Health and Environmental Sciences Department, January 1995. API. Fugitive Hydrocarbon Emissions from Oil and Gas Production Operations, API 4589, Star Environmental, 1993. This data is referenced in USEPA GHGRP

Table	Table Title	Data Source(s)	Location	Year Published	Measurement Approach	Sample Size	Original Data Source
							Regulatory Program.
		CCAC O&G Methane Partnership – Technical Guidance Document Number 2: Fugitive Component and Equipment Leaks. Climate & Clean Air Coalition. March 2017	Not specified	2017	Derived	Derived	EPA. Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017, EPA Office of Air Quality Planning and Standards, 1995
7-42	Pegged Emission Rates for the Petroleum Industry	EPA. Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017, EPA Office of Air Quality Planning and Standards, November 1995, Table 2-14	US	1995	Derived	Derived from bagging data from 24 oil and gas production facilities	API. Emission Factors for Oil and Gas Production Operations, API Publication Number 4615, Health and Environmental Sciences Department, January 1995. API. Fugitive Hydrocarbon Emissions from Oil and Gas Production Operations, API 4589, Star Environmental, 1993. This data is referenced in USEPA GHGRP Regulatory Program.
7-43	California NG Industry Leak Rate/Screening Value (SV) Correlations	Jeff Kuo, Travis C. Hicks, Brian Drake & Tat Fu Chan, 2015. Estimation of methane emission from California natural gas industry, Journal of the Air & Waste Management Association, 65:7, 844-855, DOI: 10.1080/10962247.2015.102592	US	2015	Bacharach Hi-Flow Sampler and Bagging	25 facilities with 95,157 components surveyed	Direct measurement study conducted in 2012
7-44	California NG Industry Pegged Emission Factors	Jeff Kuo, Travis C. Hicks, Brian Drake & Tat Fu Chan, 2015. Estimation of methane emission from California natural gas industry, Journal of the Air & Waste Management Association, 65:7, 844-855, DOI: 10.1080/10962247.2015.102592	US	2015	Bacharach Hi-Flow Sampler and Bagging	25 facilities with 95,157 components surveyed	Direct measurement study conducted in 2012
7.3.2.1 Natural Gas Transmission and Storage – Facility Level							
7-45	Facility-Level Average Fugitive Emission Factors for Natural Gas Transmission and Storage	Campbell et al. 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. EPA	US	1996	GRI Hi-Flow ™ Sampler or EPA Protocol Method 21	Data for gas-actuated isolation valves - provided by 16 sites and two manufacturers. Pneumatic control valves - data collected from 54 sites and 23	Direct measurement study conducted in the early 1990s and published in 1996.

Table	Table Title	Data Source(s)	Location	Year Published	Measurement Approach	Sample Size	Original Data Source
						measurements of operating devices	
		Campbell, L.M., M.V. Campbell, and D.L. Epperson. Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines, Final Report, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. EPA, June 1996	US	1996	FID to identify leak, laminar flow element (LFE) to estimate leaks below 450 scfh, and dry gas meter for leaks above 450 scfh	146 leak tests performed by participating companies out of target sample size of 200 tests	Direct measurement study conducted in the early 1990s and published in 1996. This data is referenced in USEPA GHGRP Regulatory Program.
7.3.2.2 Natural Gas Transmission and Storage – Equipment Level							
7-46	Equipment-Level Emission Factors for Natural Gas Transmission and Storage Equipment	Campbell et al. 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. EPA	US	1996	GRI Hi-Flow ™ Sampler or EPA Protocol Method 21	Data for gas-actuated isolation valves - provided by 16 sites and two manufacturers. Pneumatic control valves - data collected from 54 sites and 23 measurements of operating devices	Direct measurement study conducted in the early 1990s and published in 1996.
		Campbell, L.M. and B.E. Stapper. Methane Emissions from the Natural Gas Industry, Volume 10: Metering and Pressure Regulating, Stations in Natural Gas, and Transmission and Distribution, Final Report, GRI-94/0257.27 and EPA-600/R-96-080j. Gas Research Institute and U.S. EPA, June 1996	US	1996	Tracer Gas Technique	95 metering/pressure regulating facilities were measured at 13 different distribution and transmission companies	Direct measurement study conducted in the early 1990s and published in 1996. This data is referenced in USEPA GHGRP Regulatory Program.
		Jeff Kuo, Travis C. Hicks, Brian Drake & Tat Fu Chan, 2015. Estimation of methane emission from California natural gas industry, Journal of the Air & Waste Management Association, 65:7, 844-855, DOI: 10.1080/10962247.2015.102592	US	2015	Bacharach Hi-Flow Sampler and Bagging	25 facilities with 95,157 components surveyed	Direct measurement study conducted in 2012
7-46	Equipment-Level Emission Factors for	Zimmerle, David, et al., Methane Emissions from the Natural Gas Transmission and Storage System	US	2015	For direct emissions data, onsite tracer	Data collected in 2012 for 2292 onsite	Cites public data from GHGRP, as well as the 2015 Subramanian Study (Subramanian et al.,

Table	Table Title	Data Source(s)	Location	Year Published	Measurement Approach	Sample Size	Original Data Source
	Natural Gas Transmission and Storage Equipment	in the United States. Environmental Science & Technology, https://doi.org/10.1021/acs.est.5b01669. July 2015			flux measurements	measurements in field campaign at 45 TS facilities, additional emissions data from 677 facilities and activity data from 922 facilities	Methane Emissions from Natural gas Compressor Stations in the Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol. Environmental Science and Technology 2015)
		EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 – 2017. 2019	US	2019	These values were calculated using 2017 year-specific GHGRP Subpart W data by region.		
7-47	More Detailed Fugitive Emission Factors for Natural Gas Transmission Equipment	Campbell, L.M., M.V. Campbell, and D.L. Epperson. Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines, Final Report, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. EPA, June 1996	US	1996	FID to identify leak, LFE to estimate leaks below 450 scfh, and dry gas meter for leaks above 450 scfh	146 leak tests performed by participating companies out of target sample size of 200 tests	Direct measurement study conducted in the early 1990s and published in 1996. This data is referenced in USEPA GHGRP Regulatory program.
7-48	Fugitive Emission Factors from Underground Plastic Pipelines by Construction Year In Transmission Sector	Campbell, L.M., M.V. Campbell, and D.L. Epperson. Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines, Final Report, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. EPA, June 1996	US	1996	FID to identify leak, LFE to estimate leaks below 450 scfh, and dry gas meter for leaks above 450 scfh	146 leak tests performed by participating companies out of target sample size of 200 tests	Direct measurement study conducted in the early 1990s and published in 1996. This data is referenced in USEPA GHGRP Regulatory program.
		Southern California Gas Company (SoCal). A Study of the 1991 Unaccounted-for Gas Volume at the Southern Gas Company, April 1993	US	1993	Document not publically available without purchase.		
		California Energy Commission (CEC). Evaluation of Oil and Gas Sector Greenhouse Gas Emissions Estimation and Reporting, California Energy Commission, Consultant Report, Final Draft, April 14, 2006	US	2006	Document not publically available.		

Table	Table Title	Data Source(s)	Location	Year Published	Measurement Approach	Sample Size	Original Data Source
7.3.2.3 Natural Gas Transmission and Storage – Component Level – Average Emission Factors							
7-49	Natural Gas Transmission Compressor Station Average Component-Level Emission Factors	Howard, T., R. Kantamaneni, and G. Jones. Cost Effective Leak Mitigation at Natural Gas Transmission Compressor Stations, Final Report. PRC International, Gas Research Institute, and U.S. EPA Natural Gas STAR Program, August 1999, Tables 3 and 4	US	1999	Document not publically available without purchase.		
7-50	Natural Gas Transmission and Storage Average Component-Level Emission Factors	D.J.Picard, M. Stribrny, and M.R. Harrison. Handbook for Estimating Methane Emissions from Canadian Natural Gas Systems. GTC Program #3. Environmental Technologies, May 25, 1998, Table 4	Canada	1998	Document not publically available without purchase.		
		Hummel, et al. Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Final Report, GRI-94/0257.25 and EPA-600/R-96-080h. Gas Research Institute and U.S. EPA	US	1996	Rotameter to measure large leakage rates	Data collected at 15 compressor stations	Direct measurement study conducted in the early 1990s and published in 1996. This data is referenced in USEPA GHGRP Regulatory program.
7-51	Natural Gas Transmission Sector Average Component-Level Emission Factors: California Specific	Jeff Kuo, Travis C. Hicks, Brian Drake & Tat Fu Chan, 2015. Estimation of methane emission from California natural gas industry, Journal of the Air & Waste Management Association, 65:7, 844-855, DOI: 10.1080/10962247.2015.102592	US	2015	Bacharach Hi-Flow Sampler and Bagging	25 facilities with 95,157 components surveyed	Direct measurement study conducted in 2012
7-52	Natural Gas Storage Sector Average Component-Level Emission Factors: California Specific	Jeff Kuo, Travis C. Hicks, Brian Drake & Tat Fu Chan, 2015. Estimation of methane emission from California natural gas industry, Journal of the Air & Waste Management Association, 65:7, 844-855, DOI: 10.1080/10962247.2015.102592	US	2015	Bacharach Hi-Flow Sampler and Bagging	25 facilities with 95,157 components surveyed	Direct measurement study conducted in 2012
7-53	Natural Gas Transmission and Storage Compressor Station Average	Subramanian, R, et al., 2015. Methane Emissions from Natural Gas Compressor Stations in the Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas	US	2015	First leak detection using FLIR camera. Primary emission measurement device -	45 compressor stations in the transmission and storage (T&S) sector	Direct measurements of fugitive and vented sources conducted during summer and fall of 2013 were combined with AP-42-based exhaust

Table	Table Title	Data Source(s)	Location	Year Published	Measurement Approach	Sample Size	Original Data Source
	Component-Level Emission Factors	Reporting Program Protocol, Environmental Science & Technology, 49, 5, 3252–3261, https://doi.org/10.1021/es5060258			Bacharach Hi-Flow Sampler. Higher flow using rotary vane anemometer, calibrated bags, or turbine meters.		emission factors
7-54	Underground Natural Gas Storage Wellhead Component-Level Emission Factors	EPA, 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Table W-4B. Data reported as of August 2, 2019. https://ecfr.io/Title-40/sp40.23.98.w Part of EPA GHGRP Regulatory Program.	US	2019	Derived	Derived	GRI. Methane Emissions from the Natural Gas Industry. Volume 8. Tables 4-3, 4-6 and 4-24. June 1996.
7.3.2.4 Natural Gas Transmission and Storage – Component Level – Leaker Factors							
7-55	Whole Gas Leaker Factors for Transmission and Storage	Zimmerle, David, et al., Methane Emissions from the Natural Gas Transmission and Storage System in the United States. Environmental Science & Technology, https://doi.org/10.1021/acs.est.5b01669. July 2015	US	2015	Onsite tracer flux measurements	Data collected during 2012 including 2292 onsite measurements, additional emissions data from 677 facilities and activity data from 922 facilities	Cites public data from GHGRP, as well as the 2015 Subramanian Study (Subramanian et al Methane Emissions from Natural gas Compressor Stations in the Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol. Environmental Science and Technology 2015)
7-56	Default THC Leaker Emission Factors for Onshore Natural Gas Transmission Compression: Surveys using OGI Screening or Method 21 Surveys at 10,000 ppmv Leak Detection Threshold	EPA, 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Table W-3A. Data reported as of August 2, 2019. https://ecfr.io/Title-40/sp40.23.98.w Part of EPA GHGRP Regulatory Program.	US	2019	Derived	Derived	Clearstone. Handbook for Estimating Methane Emissions from Canadian Natural Gas Systems. Clearstone Engineering Ltd., Enerco Engineering Ltd, and Radian International. May 25, 1998. Clearstone. Measurement of Natural Gas Emissions from the Canadian Natural Gas Transmission and Distribution Industry. Clearstone Engineering Ltd., Canadian Energy Partnership for Environmental Innovation (CEPEI). April 16, 2007.

Table	Table Title	Data Source(s)	Location	Year Published	Measurement Approach	Sample Size	Original Data Source
7-57	Default THC Leaker Emission Factors for Onshore Natural Gas Transmission Compression: Method 21 Surveys at 500 ppmv Leak Detection Threshold	EPA, 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Table W-3A. Data reported as of August 2, 2019. https://ecfr.io/Title-40/sp40.23.98.w Part of EPA GHGRP Regulatory Program.	US	2019	Derived	Derived	Clearstone. Handbook for Estimating Methane Emissions from Canadian Natural Gas Systems. Clearstone Engineering Ltd., Enerco Engineering Ltd, and Radian International. May 25, 1998. Clearstone. Measurement of Natural Gas Emissions from the Canadian Natural Gas Transmission and Distribution Industry. Clearstone Engineering Ltd., CEPEI. April 16, 2007.
7-58	Default THC Leaker Emission Factors for Underground Natural Gas Storage Stations: Surveys using OGI Screening or Method 21 Surveys at 10,000 ppmv Leak Detection Threshold	EPA, 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Table W-4A. Data reported as of August 2, 2019. https://ecfr.io/Title-40/sp40.23.98.w Part of EPA GHGRP Regulatory Program.	US	2019	Derived	Derived	Assumed to be the same as the values from Tables 7.3-23 and 7.3-24, which cite the following sources: Clearstone. Handbook for Estimating Methane Emissions from Canadian Natural Gas Systems. Clearstone Engineering Ltd., Enerco Engineering Ltd, and Radian International. May 25, 1998. Clearstone. Measurement of Natural Gas Emissions from the Canadian Natural Gas Transmission and Distribution Industry. Clearstone Engineering Ltd., CEPEI. April 16, 2007.
7-59	Default THC Leaker Emission Factors for Underground Natural Gas Storage Stations: Method 21 Surveys at 500 ppm Leak Detection Threshold	EPA, 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Table W-4A. Data reported as of August 2, 2019. https://ecfr.io/Title-40/sp40.23.98.w Part of EPA GHGRP Regulatory Program.	US	2019	Derived	Derived	Assumed to be the same as the values from Tables 7.3-23 and 7.3-24, which cite the following sources: Clearstone. Handbook for Estimating Methane Emissions from Canadian Natural Gas Systems. Clearstone Engineering Ltd., Enerco Engineering Ltd, and Radian International. May 25, 1998. Clearstone. Measurement of Natural Gas Emissions from the Canadian Natural Gas Transmission and Distribution Industry. Clearstone Engineering Ltd., CEPEI. April 16, 2007.

Table	Table Title	Data Source(s)	Location	Year Published	Measurement Approach	Sample Size	Original Data Source
7-60	Default THC Leaker Emission Factors for Underground Natural Gas Storage Wellheads: Surveys using OGI Screening or Method 21 Surveys at 10,000 ppmv Leak Detection Threshold	EPA, 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Table W-4A. Data reported as of August 2, 2019. https://ecfr.io/Title-40/sp40.23.98.w Part of EPA GHGRP Regulatory Program.	US	2019	Derived	Derived	EPA. Protocol for Equipment Leak Emission Estimates. Emission Standards Division. U.S. EPA. November 1995.
7-61	Default THC Leaker Emission Factors for Underground Natural Gas Storage Wellheads: Method 21 Surveys at 500 ppm Leak Detection Threshold	EPA, 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Table W-4A. Data reported as of August 2, 2019. https://ecfr.io/Title-40/sp40.23.98.w Part of EPA GHGRP Regulatory Program.	US	2019	Derived	Derived	EPA. Protocol for Equipment Leak Emission Estimates. Emission Standards Division. U.S. EPA. November 1995.
7.3.4.1 Natural Gas Distribution – Facility Level							
7-62	Facility-Level Average Fugitive Emission Factors for Natural Gas Distribution	Campbell et al. 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. EPA	US	1996	M&R facilities used Tracer Gas, Underground pipelines used leak statistics method	95 M&R facilities, with activity data supplied by 12 distribution companies Underground pipeline leak data from two distribution companies	Direct measurement study conducted in the early 1990s and published in 1996.
		Campbell, L.M., M.V. Campbell, and D.L. Epperson. Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines, Final Report, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. EPA, June 1996	US	1996	FID to identify leak, LFE to estimate leaks below 450 scfh, and dry gas meter for leaks above 450 scfh	146 leak tests performed by participating companies out of target sample size of 200 tests	Direct measurement study conducted in the early 1990s and published in 1996. This data is referenced in USEPA GHGRP Regulatory program.

Table	Table Title	Data Source(s)	Location	Year Published	Measurement Approach	Sample Size	Original Data Source
7.3.4.2 Natural Gas Distribution – Equipment Level							
7-63	Equipment-Level Fugitive Emission Factors for Gas Distribution Equipment	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. EPA, June 1996	US	1996	M&R facilities used Tracer Gas, Underground pipelines used leak statistics method	95 M&R facilities, with activity data supplied by 12 distribution companies Underground pipeline leak data from two distribution companies	Direct measurement study conducted in the early 1990s and published in 1996.
		Hummel, K.E., L.M. Campbell, and M.R. Harrison. Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Final Report, GRI-94/0257.1 and EPA-600/R-96-080b. Gas Research Institute and U.S. EPA, June 1996	US	1996	GRI Hi-Flow ™ Sampler or EPA Protocol Method 21	Meter sets were estimated using data from 10 local distribution companies	Direct measurement study conducted in the early 1990s and published in 1996. This data is referenced in USEPA GHGRP Regulatory program.
7-64	Equipment-Level Fugitive Emission Factors for Distribution M&R Stations	Campbell, L.M. and B.E. Stapper. Methane Emissions from the Natural Gas Industry, Volume 10: Metering and Pressure Regulating, Stations in Natural Gas, and Transmission and Distribution, Final Report, GRI-94/0257.27 and EPA-600/R-96-080j. Gas Research Institute and U.S. EPA, June 1996	US	1996	Tracer Gas Technique	95 metering/pressure regulating facilities were measured at 13 different distribution and transmission companies	Direct measurement study conducted in the early 1990s and published in 1996. This data is referenced in USEPA GHGRP Regulatory program.
7-65	Additional Fugitive Emission Factors for Above-Grade Distribution M&R City Gate Stations	EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 – 2017. 2019	US	2019	These values were calculated using 2017 year-specific GHGRP Subpart W data by region.		
7-66	Fugitive Emission Factors for Below Grade M&R Stations	EPA, 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Table W-7. Data reported as of August 2, 2019. https://ecfr.io/Title-40/sp40.23.98.w	US	2019	Derived	Derived	GRI. Methane Emissions from the Natural Gas Industry. Volume 10. Table 7-1. June 1996.

Table	Table Title	Data Source(s)	Location	Year Published	Measurement Approach	Sample Size	Original Data Source
		Part of USEPA GHGRP Regulatory Program.					
7-67	More Detailed Equipment-Level Fugitive Emission Factors for Natural Gas Distribution Equipment	Campbell, L.M., M.V. Campbell, and D.L. Epperson. Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines, Final Report, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. EPA, June 1996	US	1996	FID to identify leak, LFE to estimate leaks below 450 scfh, and dry gas meter for leaks above 450 scfh	146 leak tests performed by participating companies out of target sample size of 200 tests	Direct measurement study conducted in the early 1990s and published in 1996. This data is referenced in USEPA GHGRP Regulatory program.
7-68	Additional Equipment-Level Fugitive Emission Factors for Natural Gas Distribution Equipment	EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 – 2017. 2019	US	2019	These values were calculated using 2017 year-specific GHGRP Subpart W data by region.		
7-69	Fugitive Emission Factors from Distribution Underground Plastic Pipelines by Construction Year	Campbell, L.M., M.V. Campbell, and D.L. Epperson. Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines, Final Report, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. EPA, June 1996	US	1996	FID to identify leak, LFE to estimate leaks below 450 scfh, and dry gas meter for leaks above 450 scfh	146 leak tests performed by participating companies out of target sample size of 200 tests	Direct measurement study conducted in the early 1990s and published in 1996. This data is referenced in USEPA GHGRP Regulatory program.
		SoCal. A Study of the 1991 Unaccounted-for Gas Volume at the Southern Gas Company, April 1993	US	1993	Document not publically available without purchase.		
		CEC. Evaluation of Oil and Gas Sector Greenhouse Gas Emissions Estimation and Reporting, California Energy Commission, Consultant Report, Final Draft, April 14, 2006	US	2006	Document not publically available.		
7.3.4.3 Natural Gas Distribution – Component Level – Average Emission Factor							
7-70	Natural Gas Distribution M&R Stations Average Component-Level Emission Factors	Ross, B.D. and D.J. Picard, Measurement of Methane Emissions from Western Canadian Natural Gas Facilities, Gas Technology Canada, GTC Program #3, Environment Technology Program, September, 1996	Canada	1996	Document not publically available.		

Table	Table Title	Data Source(s)	Location	Year Published	Measurement Approach	Sample Size	Original Data Source
7-71	Natural Gas Distribution Commercial and Residential Sites Average Component-Level Emission Factors	Picard, D. J., B. D. Ross, and D. W. H. Koon. A Detailed Inventory of CH4 and VOC Emissions from Upstream Oil and Gas Operations in Alberta, Volume II, Canadian Petroleum Association, March 1992	Canada	1992	Document not publically available without purchase.		
7-72	Natural Gas Distribution Commercial and Industrial Meter Emission Average Component-Level Factors, by Region	Gas Technology Institute. Classification of Methane Emissions from Industrial Meters, Vintage vs Modern Plastic Pipe, and Plastic-lined Steel and Cast-Iron Pipe. Final Report. U.S. Department of Energy. DOE Project Number DE-FE0029061. 30 June 2019	US	2019	Bacharach Hi-Flow Sampler, gas concentration analyzer, SF6 analyzer	24,670 components examined across six regions	Direct measurement study
7-73	Additional Natural Gas Distribution Component-Level Emission Factors from California Study	Jeff Kuo, Travis C. Hicks, Brian Drake & Tat Fu Chan, 2015. Estimation of methane emission from California natural gas industry, Journal of the Air & Waste Management Association, 65:7, 844-855, DOI: 10.1080/10962247.2015.102592	US	2015	Bacharach Hi-Flow Sampler and Bagging	25 facilities with 95,157 components surveyed	Direct measurement study
7.3.4.4 Natural Gas Distribution – Component Level – Leaker Factors							
7-74	Natural Gas T-D Transfer Station Component-Level Leaker Emission Factors	EPA, 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Table W-7. Data reported as of August 2, 2019. https://ecfr.io/Title-40/sp40.23.98.w Part of EPA GHGRP Regulatory Program.	US	2019	Derived	Derived	GRI/EPA 1996 Study GRI. Methane Emissions from the Natural Gas Industry. Volume 9, Tables 8-9 and 9-4. June 1996
7-75	Natural Gas Distribution Commercial and Industrial Meter Leaker Emission Factors, by Region	Gas Technology Institute. Classification of Methane Emissions from Industrial Meters, Vintage vs Modern Plastic Pipe, and Plastic-lined Steel and Cast-Iron Pipe. Final Report. U.S. Department of Energy. DOE Project Number DE-FE0029061. 30 June 2019	US	2019	Hi-Flow Sampler, gas concentration analyzer, SF6 analyzer	24,670 components examined across six regions	Direct measurement study conducted in 2019.

Table	Table Title	Data Source(s)	Location	Year Published	Measurement Approach	Sample Size	Original Data Source
7.3.6.1 LNG Operations – Facility Level							
7-76	Facility Level Emission Factors for LNG Storage and LNG Import/Export Terminals	U.S. Environmental Protection Agency (EPA, 2019b). Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 – 2017. 2019.	US	2019	Leak data reported under US GHGRP Subpart W.	7 US LNG storage facilities; 14 US LNG Terminals	Data is based on a 4 year average of US GHGRP Subpart W data.
7.3.6.2 LNG Operations – Equipment Level							
Unnumbered table in Section 7.3.6.1	N/A	EPA, 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems, Table W-5B and Table W-6B. Data reported as of August 2, 2019. https://ecfr.io/Title-40/sp40.23.98.w Part of EPA GHGRP Regulatory Program.	US	2019	Derived	Derived	EPA. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007. Annexes. Tables A-112 – A-125. U.S. EPA. April 2009.
7.3.6.4 LNG Operations – Component Level – Leaker Factors							
7-77	Default Methane Leaker Emission Factors for LNG Storage: Surveys using OGI and Method 21 Screening at 10,000 ppmv Leak Threshold	EPA, 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Table W-5A and Table W-6A. Data reported as of August 2, 2019. https://ecfr.io/Title-40/sp40.23.98.w Part of EPA GHGRP Regulatory Program.	US	2019	Derived	Derived	Protocol for Equipment Leak Emission Estimates. Emission Standards Division. USEPA. SOCMI Table 2-7 November 1995.
7-78	Default Methane Leaker Emission Factors for LNG Storage: Method 21 Surveys at 500 ppm Leak Detection Threshold	EPA, 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Table W-5A and Table W-6A. Data reported as of August 2, 2019. https://ecfr.io/Title-40/sp40.23.98.w Part of EPA GHGRP Regulatory Program.	US	2019	Derived	Derived	Protocol for Equipment Leak Emission Estimates. Emission Standards Division. USEPA. SOCMI Table 2-7 November 1995.

Table 7-34. Facility-Level Average Fugitive Emission Factors for Natural Gas Plants

Source	Methane Emission Factor, Original Units		Methane Content (mole %)	Methane Emission Factor, Converted to Tonnes Basis [a]		Uncertainty (%) [b]	Whole Gas Emission Factor	
Natural Gas Processing Plants [c]	99.2	lb $CH_4/10^6$ scf processed	86.8	4.507E-02	tonnes $CH_4/10^6$ scf processed	82.2	2,708	scf gas/10^6 scf processed
				1.592E+00	tonnes $CH_4/10^6$ sm^3 processed		2.708E-03	sm^3 gas/sm^3 processed
Natural Gas Processing Plants [d, e]	22,984.25	kg CH_4/ plant-yr	86.8	2.62E-03	tonnes CH_4/plant-hr [f]	Not Specified	157.98	scf gas/plant-yr

Footnotes and Sources:

[a] The emission factors can be adjusted based on the relative concentrations of CH_4 and CO_2 to estimate CO_2 emissions.

[b] Uncertainty is based on a 95% confidence interval from the data used to develop the original emission factor

[c] 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.

[d] EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 – 2017. 2019. These values were calculated using 2017 year-specific GHGRP Subpart W data by region. Note: These factors, used in the USEPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 – 2017 (EPA, 2019), are updated annually based on data reported from operators under the GHGRP.

[e] This factor is based on data from 667 reported natural gas processing plants (EPA, 2019).

[f] Assumes 8760 hour per year operation.

[e] Note that this emission factor was derived from the following values: estimated gas processing plant fugitive methane emissions at 2.095 x 10^9 scf CH_4/yr (Harrison, et al., Volume 2, 1996) and estimated annual gas processed amount at 24,704.38 x 10^9 scf gas/yr (EIA, 2021). This emission factor was originally placed in the equipment-level section of the Compendium, but has been moved to facility-level since it was derived from gas processing plant emissions data from Appendix A of Volume 2 of the GRI/EPA study (Harrison, et al., 1996). See full derivation in Appendix C, Section C.3.3.

It should be noted that the level of accuracy provided with the facility emission factors in Table 7-34 may not be sufficient for many facilities considering the increased focus on methane emissions. If the facility is atypical of the industry average or greater accuracy is needed to support emission reduction estimates, one of the more rigorous approaches should be used.

In addition to CH_4, CO_2 also may be released from equipment leak sources if CO_2 is present in the gas stream. Fugitive equipment leak emission factors specific to CO_2 are limited in current, publicly available studies. As an approximation, the CH_4 emission factor can be adjusted to account for the CO_2 composition of the gas for equipment leak sources. This conversion is shown in Section 7.2.1.1 and Exhibit 7-1.

7.3.1.2 Equipment Level

The equipment-level average emission factor approach allows the fugitive emission estimate to be tailored to a particular facility based on the population of major equipment at the facility. In the absence of component count data, the equipment-level approach can be used when counts of major equipment at a gas processing plant is known. Exhibit 7-4 presents an example of calculating CH_4 emissions using the major equipment emission factors approach.

Gas processing equipment level emission factors are presented in Table 7-35. These emission factors are taken or derived from the GRI/EPA U.S. methane emissions study (Harrison, et al., 1996), and categorized by type of compressor unit with witch the components are associated with, as well as non-compressor related components in the balance of the gas processing plant. The default CH_4 concentration associated with these emission factors provided in Table D-4 is 86.8 mole %. The emission factors can be adjusted for other CH_4 concentrations by the ratio of the actual CH_4 content to the default value. The emission factors can also be used to estimate CO_2 emissions based on the ratio of CO_2 to CH_4 in the produced gas. These adjustments are demonstrated in Section 7.2.1.1.

Table 7-35. Equipment-Level Methane Emission Factors for Natural Gas Processing Equipment

Equipment Basis	Original Emission Factor [a, b]		Methane Content (mole %)	Methane Emission Factor, Converted to Tonnes Basis [c]		Uncertainty [d] (± %)	Converted Emission Factor [c], Whole Gas	
Non-compressor equipment, based on gas processing volume [e]	201.02	scf CH_4/MMscf processed	86.8	3.85E-03	tonne CH_4/MMscf processed	58.1	231.76	scf gas/MMscf processed
				1.36E-01	tonne CH_4/10^6 sm^3 processed		2.32E-04	sm^3 gas/sm^3 processed
Reciprocating compressors in processing	11,198	scf CH_4/ compressor-day		8.95E-03	tonne CH_4/compressor-hr	95.2	12,901	scf gas/ Compressor-day
Centrifugal compressors in processing	21,230	scf CH_4/ compressor-day		1.70E-02	tonne CH_4/compressor-hr	51.8	24,459	scf gas/ compressor-day

Footnotes and Sources:

[a] 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.

[b] Hummel, K.E., L.M. Campbell, and M.R. Harrison. *Methane Emissions from the Natural Gas Industry*, *Volume 8: Equipment Leaks, Final Report*, GRI-94/0257.25 and EPA-600/R-96-080h. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[c] Emission factors converted are based on 60 °F and 14.7 psia. The average CH_4 concentration associated with these emission factors provided in Table D-4 is 86.8 mole %. If the actual CH_4 content differs from the default value, the emission factors shown above can be adjusted by the ratio of the site CH_4 content to the default concentration.

[d] Uncertainty is based on a 95% confidence interval from the data used to develop the original emission factor.

[e] Note that this emission factor was derived from the following values: estimated gas processing plant fugitive methane emissions at 2.095×10^9 scf CH_4/yr (Harrison, et al., Volume 2, 1996) and estimated 2020 annual gas processed amount at $24{,}704.38 \times 10^9$ scf gas/yr (EIA, 2021). This emission factor was originally placed in the equipment-level section of the Compendium, but has been moved to facility-level since it was derived from gas processing plant emissions data from Appendix A of Volume 2 of the GRI/EPA study (Harrison, et al., 1996). See full derivation in Appendix C, Section C.3.3.

7.3.1.3 Component Level – Average Emission Factor

The component-level average emission factor approach is based on the number of components in the facility. Where no monitoring data is available, this approach provides a more accurate estimation than equipment or facility level emission factors, since it is based on site-specific component population data. This methodology requires component counts; however, if this information is not available generic counts can be obtained as detailed in Appendix C, Section C.1.2.

Some component-level average emission factors were developed for estimating TOC, also referred to as THC, or VOC (i.e., non-methane, non-ethane hydrocarbons), rather than CH_4. Section 7.2.1.3 includes a methodology for converting the TOC-based emission factors to CH_4 fugitive equipment leak emissions, based on either site-specific data or on a default composition by type of facility. An example calculation illustrating the use of component-level fugitive emission factors is provided in Exhibit 7-2.

Table 7-36 presents natural gas plant, average THC average component-level emissions factors based on a comprehensive measurement program, conducted to determine the baseline emissions rates for cost-effective directed inspection and maintenance (DI&M) control opportunities (EPA, 2006). This report presents baseline (i.e., pre-DI&M) fugitive equipment leak emission factors from two phases of site measurements. Phase I of the program was conducted at four gas processing plants in the Western U.S. during 2000. Phase II of the program was conducted at five gas processing plants, seven gathering compressor stations, and 12 well sites during 2004 and 2005. The report shows that the measured THC emission rates from leaking components during Phase II of the study were 1,348 tonnes/facility-yr for gas plants, 131 tonnes/facility-yr for gathering compressor stations, and 8 tonnes/facility-yr for well sites. Based on the counts of the facilities and measured leak rates, the measured THC leak rates were approximately comprised of 86.9% from gas plants, 11.8% from gathering compressor stations, and 1.2% from well sites. The emission factors for Phase II are also presented in Section 7.2.3.3 since they are also applicable to the gathering and boosting and production segments.

Table 7-36. Natural Gas Plant, Gathering Compressor Station, and Well Site Average Component-Level Emission Factors

Component	Phase I (Gas Plants) [b]		Uncertainty (± %)	Phase II (Gas Plants, Gathering Compressor Stations, and Well Sites) [c]	
	Average THC Emission Factor [a], Original Units, kg THC/ source-hr	Average THC Emission Factor, Converted to tonne THC/ source-hr		Average THC Emission Factor [a], Original Units, kg THC/ source-hr	Average THC Emission Factor, Converted to tonne THC/ source-hr
Connectors	2.22E-03	2.22E-06	Not specified	3.30E-03	3.30E-06
Block Valves	1.10E-02	1.10E-05		1.47E-02	1.47E-05
Control Valves	4.85E-02	4.85E-05		3.73E-02	3.73E-05
Pressure Relief Valves (PRV)	6.73E-02	6.73E-05		4.70E-04	4.70E-07
Pressure Regulators	1.74E-02	1.74E-05		6.31E-03	6.31E-06
Orifice Meters	3.58E-03	3.58E-06		2.70E-03	2.70E-06
Crank Case Vents	8.83E-01	8.83E-04		1.20E-01	1.20E-04
Open-Ended Lines (OEL)	5.18E-02	5.18E-05		2.39E-01	2.39E-04
Compressor Seals [d]	8.52E-01	8.52E-04		5.20E-01	5.20E-04

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (EPA). *EPA Phase II Aggregate Site Report: Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites, Technical Report*, prepared by National Gas Machinery Laboratory, Clearstone Engineering, Ltd., and Innovative Environmental Solutions, Inc., March 2006, Table 4.

[b] Phase I of the study was based on surveys at four gas processing facilities in the Western U.S. completed during the 4th quarter of 2000.

[c] Phase II of the study was based on surveys at five gas processing plants, seven gathering compressor stations, and 12 well sites during the first quarter of 2004 and second quarter of 2005. Table 3 of the above referenced report shows that the measured THC emission rates from the leaking components were 1348 tonnes/facility-yr for gas plants, 131 tonnes/facility-yr for gathering compressor stations, and 8 tonnes/facility-yr for well sites. Based on the counts of the facilities and measured leak rates, the measured leak rates were comprised of 86.9% from gas plants, 11.8% from gathering compressor stations, and 1.2% from well sites.

[d] Compressor seals component category accounts for emissions from individual compressor seals. As compressor seal leakage was typically measured from common vent and drain lines, emissions have been divided evenly among the seals on units with detected leakage.

Table 7-37 shown below provides average component-level natural gas processing plant emission factors.

Table 7-37. API Natural Gas Processing Plant Average Component-Level Emission Factors

Component	Emission Factor, Original Units [a], lb TOC/ component-day	Uncertainty (± %)	Emission Factor, Converted to tonne TOC/ component-hr
Valves	2.04E-01	Not specified	3.86E-06
Pump seals	6.09E-01		1.15E-05
Others	2.57E-01		4.86E-06
Connectors	1.45E-02		2.74E-07
Flanges	2.32E-02		4.38E-07
Open-ended lines	5.46E-02		1.03E-06

Footnote and Source:

[a] American Petroleum Institute (API). *Emission Factors for Oil and Gas Production Operations*, API Publication Number 4615, Health and Environmental Sciences Department, January, 1995, Table ES-1.

Note that Table 7-20 in Section 7.2.2.3 contains component-level emission factors based on each component's respective equipment, including dehydrators, separators, piping segments, reciprocating compressors, and centrifugal compressors, that are also applicable to the Processing sector.

7.3.1.4 Component Level – Leaker Factors

Component-level leaker emission factors for onshore natural gas processing are presented in Table 7-38 and were obtained from 40 CFR 98, Subpart W, "Mandatory Greenhouse Gas Reporting – Petroleum and Natural Gas Systems", Table W-2. These emission factors are categorized as compressor-related components (i.e., components associated with the compressor units including the reciprocating engine or gas turbine drivers) and non-compressor components. The rationale for this categorization is that equipment components subject to vibration associated with compressors are found to leak at higher rates than equipment components in the balance of the gas processing plant. In order to apply these factors appropriately, the overall number of components needs to be subcategorized by compressor and non-compressor leaks.

Table 7-38. EPA 40 CFR 98 Subpart W Component-Level Leaker Emission Factors for Natural Gas Processing

Component	Emission Factor Original Units [a] scf THC/ component-hr	Uncertainty (± %)
Compressor Components		
Valve [b]	14.84	Not specified
Connector	5.59	
Open-Ended Line	17.27	
Pressure Relief Valve	39.66	
Meter	19.33	
Non-Compressor Components		
Valve [b]	6.42	Not specified
Connector	5.71	
Open-Ended Line	11.27	
Pressure Relief Valve	2.01	
Meter	2.93	

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (USEPA), 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Table W-2. Data reported as of August 2, 2019. https://ecfr.io/Title-40/sp40.23.98.w.

[b] Valve includes control valves, block valves and regulator valves.

7.3.1.5 Component Level – Screening Range Factor

The screening range factor approach, also called the leak/no-leak approach, is discussed in Section 7.2.1.5.

Table 7-39 presents screening emission factors for natural gas processing based on processing facility emission factors from API Publication No. 4615 Emission Factors for Oil and Gas Production Operations, which include service type. Table 7-39 also includes emission factors applicable to all sectors, for reference.

Table 7-39. API Natural Gas Processing Screening Factors

Component – Service Type	Emission Factor, Original Units, [a, b] lb TOC/component-day		Emission Factor, Converted to Tonne [b], tonne TOC/ component-hr		Uncertainty (± %)
	< 10,000 ppmV	≥ 10,000 ppmV	< 10,000 ppmV	≥ 10,000 ppmV	
Facility Type – All Sectors [c]					
Valves – All Service	NA	3.381	NA	6.39E-05	Not Specified
Connectors – All Service	NA	1.497	NA	2.83E-05	
Flanges – All Service	NA	4.490	NA	8.49E-05	
Open-ended Lines – All Service	NA	1.600	NA	3.02E-05	
Pump Seals – All Service	NA	3.905	NA	7.38E-05	
Others – All Service	NA	3.846	NA	7.27E-05	
Facility Type – Processing					
Valves – Gas Service	1.81E-03	3.381	3.42E-08	6.39E-05	Not specified
Connectors – Gas Service	5.76E-04	1.497	1.09E-08	2.83E-05	
Flanges – Gas Service	1.44E-03	4.49	2.72E-08	8.49E-05	
Open-ended Lines – Gas Service	1.62E-03	1.6	3.06E-08	3.02E-05	
Pump Seals – Gas Service	4.30E-02	3.905	8.13E-07	7.38E-05	
Others – Gas Service	9.09E-03	3.846	1.72E-07	7.27E-05	

Footnotes and Sources:

[a] American Petroleum Institute (API). *Emission Factors for Oil and Gas Production Operations*, API Publication No. 4615, Health and Environmental Sciences Department, January 1995, Table ES-2.

[b] NA means not available on the "all facilities" basis. The emission factors for leaking components were developed as a single factor across all facility types. The emission factors for non-leaking components, however, were developed for each facility type.

[c] These screening factors have no specified facility type and are assumed to be applicable for all sectors.

7.3.1.6 Correlation Equations Using Method 21 Monitoring

The correlation approach predicts the mass emission rate as a function of the screening value for a particular equipment type as detailed in Section 7.1.4.3. The emission factors and equations used for determining emissions using this approach are presented in this section below. While the correlation equations presented in this section are broadly applicable across industry sectors, the

Method 21 screening approach is more commonly used in the gas processing and transmission segments of the industry.

The correlation equations apply to the entire range of the analyzer used for monitoring. The form of the correlation is:

$$E_{TOC} = A \times SV^{B} \qquad \text{(Equation 7-10)}$$

where

E_{TOC} = emission rate expressed as kg of TOC/hour;

A and B = constants developed in the correlation fitting; and

SV = screening value in ppmv estimated according to U.S. EPA Method 21.

The correlation equations do not directly allow for estimating the emissions for components whose monitoring value is below the lower limit of detection of the analyzer (often called “default zero”) or above the upper limit of detection (often called “pegged”). Default zero and pegged emission factors are used for these types of readings as an adjunct to the correlation equations. These default zero or pegged emission factors are applied as in the following equation:

$$E_{TOC} = F_{A} \times N \qquad \text{(Equation 7-11)}$$

where

F_A = the applicable default zero or pegged emission factor and

N = the number of components found to be default zeros or pegged components.

The below set of tables, Table 7-40 through 7-42, are used together to quantify equipment leak emissions applying the correlation approach, which rely on the Method 21 screening data. As indicated above, the correlation equations apply to the entire screening range of the instrument, whereas the default zero and pegged emission factors apply to the components screened that were below or above the detection limit of the instrument, respectively.

Table 7-40 presents correlation equations for various component types that are applicable across the entire petroleum industry. These correlation equations are also cited by the methane reporting guidance from the Climate & Clean Air Coalition (CCAC, 2017).

Table 7-40. Petroleum Industry Leak Rate/Screening Value (SV) Correlations

Equipment Type	**Leak Rate Correlation Equation [a, b]**		**Uncertainty (± %)**
	kg TOC/hr/component	**tonne TOC/hr/component**	
Valves	$2.29E\text{-}06 \times (SV)^{0.746}$	$2.29E\text{-}09 \times (SV)^{0.746}$	Not Specified
Pump Seals	$5.03E\text{-}05 \times (SV)^{0.610}$	$5.03E\text{-}08 \times (SV)^{0.610}$	
Connectors	$1.53E\text{-}06 \times (SV)^{0.735}$	$1.53E\text{-}09 \times (SV)^{0.735}$	
Flanges	$4.61E\text{-}06 \times (SV)^{0.703}$	$4.61E\text{-}09 \times (SV)^{0.703}$	
Open-Ended Lines	$2.20E\text{-}06 \times (SV)^{0.704}$	$2.20E\text{-}09 \times (SV)^{0.704}$	
Others [c]	$1.36E\text{-}05 \times (SV)^{0.589}$	$1.36E\text{-}08 \times (SV)^{0.589}$	

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (EPA). *Protocol for Equipment Leak Emission Estimates*, EPA-453/R-95-017, EPA Office of Air Quality Planning and Standards, November 1995, Table 2-10.

[b] SV stands for Screening Value, entered in units of ppmv.

[c] Other equipment type was derived from instruments, loading arms, pressure relief valves, stuffing boxes, and vents. This type should be applied to any refinery equipment other than valves, pump seals, connectors, flanges, or open-ended lines.

Table 7-41 presents default zero emission factors for the petroleum industry that are applied to components screened using Method 21 that are below the lower detection limit of the instrument.

Table 7-41. Default Zero Values for the Petroleum Industry

Equipment Type	Original Emission Factor, kg TOC/comp/hr [a]	Methane Content (%) [b]	Emission Factor, Converted to tonnes TOC/comp/hr	Uncertainty (± %)	Whole Gas Emission Factor, scf TOC/comp/hr [d]
Valves	7.8E-06	86.8	7.80E-09	Not specified	3.06E-04
Pump Seals	2.4E-05		2.40E-08		9.41E-04
Connectors	7.5E-06		7.50E-09		2.94E-04
Flanges	3.1E-07		3.10E-10		1.22E-05
Open-Ended Lines	2.0E-06		2.00E-09		7.84E-05
Others [c]	4.0E-06		4.00E-09		1.57E-04

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (EPA). *Protocol for Equipment Leak Emission Estimates*, EPA-453/R-95-017, EPA Office of Air Quality Planning and Standards, November 1995, Table 2-12.

[b] The average CH_4 concentration associated with these emission factors provided in Table D-4 is 86.8 mole %. The CH_4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH_4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

[c] Other equipment type was derived from instruments, loading arms, pressure relief valves, stuffing boxes, and vents. This type should be applied to any equipment other than valves, pump seals, connectors, flanges, or open-ended lines.

[d] CCAC O&G Methane Partnership – Technical Guidance Document Number 2: Fugitive Component and Equipment Leaks. Climate & Clean Air Coalition. March 2017.

Table 7-42 presents pegged emission factors for the petroleum industry that are applied to those screened components that exceed the upper detection limit of the instrument, or 'peg' the instrument.

Table 7-42. Pegged Emission Rates for the Petroleum Industry

Equipment Type	Original Emission Factor, kg TOC/component-hr [a]		Uncertainty (± %)	Methane Emission Factor, Converted to tonnes TOC/ component-hr	
	10,000 ppm Pegged	100,000 ppm Pegged		10,000 ppm Pegged	100,000 ppm Pegged
Valves	0.064	0.140	Not specified	6.4E-05	1.4E-04
Pump Seals	0.074	0.160		7.4E-05	1.6E-04
Connectors	0.028	0.030		2.8E-05	3.0E-05
Flanges	0.085	0.084		8.5E-05	8.4E-05
Open-Ended Lines	0.030	0.079		3.0E-05	7.9E-05
Others [b]	0.073	0.110		7.3E-05	1.1E-04

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (EPA). *Protocol for Equipment Leak Emission Estimates*, EPA-453/R-95-017, EPA Office of Air Quality Planning and Standards, November 1995, Table 2-14.

[c] The other equipment type was developed for instruments, loading arms, pressure relief valves, stuffing boxes, vents, compressors, dump lever arms, diaphragms, drains, hatches, meters and polished rods. This type should be applied to any equipment other than valves, pump seals, connectors, flanges, or open-ended lines.

It should be noted that the 10,000 ppmv pegged emission rate was based on components that screened at greater than or equal to 10,000 ppmv. It is quite possible that many of those components would have screened at greater than 100,000 ppmv if a dilution probe had been available to make the measurement. Because of this overlap of data, some pegged emission factors at the 10,000 and 100,000 ppmv levels are similar.

It should also be noted that only two data points were available for the pump seal 100,000 pegged emission rate. Rather than base an emission factor on this small amount of data, a ratio between the 10,000 and 100,000 ppmv emission factors for all the other equipment types was developed. This ratio was used to extrapolate the 100,000 ppmv emission factor for pumps from the 10,000 ppmv emission factor.

The next set of tables include more recent correlation equations and pegged emission factors derived for the California natural gas industry, based on studies in California conducted on the value chain for conventional natural gas (Kuo, et al., 2015). Note that the California study did not publish default zero emission factors because the lower detection limit of the instrument used in the study was very low (100 ppmv) and few components were identified below this detection limit. Table 7-43 presents the correlation equations that are applied to components with screening values within the detection range of the instrument.

Table 7-43. California NG Industry Leak Rate/Screening Value (SV) Correlations

Equipment Type	**Leak Rate Correlation Equation** [a, b]		**Uncertainty (± %)**
	kg CH_4/hr/component	**tonne CH_4/hr/component**	
Flanges	$4.52E-05 \times (SV)^{0.6549}$	$4.52E-08 \times (SV)^{0.6549}$	Not specified
Manual Valves	$6.78E-04 \times (SV)^{0.2811}$	$6.78E-07 \times (SV)^{0.2811}$	
Others	$3.39E-04 \times (SV)^{0.5353}$	$3.39E-07 \times (SV)^{0.5353}$	
Seals	$1.00E-04 \times (SV)^{0.6816}$	$1.00E-07 \times (SV)^{0.6816}$	
Threaded Connections	$6.78E-04 \times (SV)^{0.3031}$	$6.78E-07 \times (SV)^{0.3031}$	

Footnotes and Sources:

[a] Jeff Kuo, Travis C. Hicks, Brian Drake & Tat Fu Chan (2015) Estimation of methane emission from California natural gas industry, Journal of the Air & Waste Management Association, 65:7, 844-855, DOI: 10.1080/10962247.2015.102592.

[b] SV stands for Screening Value, entered in units of ppmv.

Table 7-44 presents pegged emission factors derived from the California NG industry study.

Table 7-44. California NG Industry Pegged Emission Factors

Equipment Type	**Original Emission Factor, lb CH_4/component-day** [a]		**Methane Content (%)** [b]	**Methane Emission Factor, Converted to tonnes CH_4/ component-day**		**Uncertainty (± %)**	**Converted Whole Gas Emission Factor, scf gas/component-hr**	
	≥ 10,000 ppm Pegged	**≥ 50,000 ppm Pegged**		**≥ 10,000 ppm Pegged**	**≥ 50,000 ppm Pegged**		**≥ 10,000 ppm Pegged**	**≥ 50,000 ppm Pegged**
Flanges	2.81	4.48	86.8	1.27E-03	2.03E-03	Not specified	3.20	5.10
Manual Valves	1.01	1.18		4.58E-04	5.35E-04		1.15	1.34
OELs	7.14	17.24		3.24E-03	7.82E-03		8.13	19.62
Others	6.01	6.94		2.73E-03	3.15E-03		6.84	7.90
Seals	21.79	23.43		9.88E-03	1.06E-02		24.80	26.66
Threaded Connection	0.93	1.01		4.22E-04	4.58E-04		1.06	1.15

Footnotes and Sources:

[a] Jeff Kuo, Travis C. Hicks, Brian Drake & Tat Fu Chan (2015) Estimation of methane emission from California natural gas industry, Journal of the Air & Waste Management Association, 65:7, 844-855, DOI: 10.1080/10962247.2015.102592.

[b] The average CH_4 concentration associated with these emission factors provided in Table D-4 is 86.8 mole %. The CH_4 emission factor can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH_4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

An example calculation illustrating the use of the component-level screening factors is provided in Exhibit 7-5.

EXHIBIT 7-5: Sample Calculation for the Correlation Approach

INPUT DATA:

Assume there are 100 flanges in a gas plant and that no composition data are available. Ninety-five of the flanges had a screening value of non-detect, 4 flanges had a screening value of 7,950 ppmv, and the remaining 1 flange had a screening factor of >10,000 ppmv (note: these example monitoring data have been simplified to make the example easier to follow). Calculate the CH_4 emissions.

CALCULATION METHODOLOGY:

Because plant-specific composition data is not available, the composition data will be taken from Table C-1 (presented in Appendix C, Section C.1.1) since the components are not classified by service type. The default CH_4 concentration is 56.4%, or a weight fraction of 0.564.

TOC emissions are calculated using Equations 7-10 and 7-11:

From Table 7-41, emissions from default zeros are:

$$E_{\text{TOC, Default Zeros}} = 3.1\times10^{-7}\ \frac{\text{kg}}{\text{hr}\times\text{flange}}\times 95\ \text{flanges}$$

$$\underline{E_{\text{TOC, Default Zeros}} = 2.95\times10^{-5}\ \text{kg TOC/hr}}$$

From Table 7-40, emissions within the correlation range are:

$$E_{\text{TOC, Correlation}} = 4.61\times10^{-6}\times(7950)^{0.703}\ \frac{\text{kg TOC}}{\text{hr}\times\text{flange}}\times 4\ \text{flanges}$$

$$\underline{E_{\text{TOC, Correlation}} = 1.02\times10^{-2}\ \text{kg TOC/hr}}$$

From Table 7-42, emissions from pegged components are:

$$E_{\text{TOC, Pegged}} = 0.085 \frac{\text{kg}}{\text{hr} \times \text{flange}} \times 1 \text{ flange}$$

$$\underline{E_{\text{TOC, Pegged}} = 8.5 \times 10^{-2} \text{ kg TOC/hr}}$$

EXHIBIT 7-5: Sample Calculation for the Correlation Approach, continued

Summing these results, the total TOC emissions are:

$$E_{\text{TOC, Total}} = \left(2.95 \times 10^{-5} + 1.02 \times 10^{-2} + 8.5 \times 10^{-2}\right)$$

$$\underline{E_{\text{TOC, Total}} = 9.5 \times 10^{-2} \text{ kg TOC/hr}}$$

The CH_4 emissions are calculated using Equation 7-6:

$$E_{CH_4} = 9.5 \times 10^{-2} \frac{\text{kg TOC}}{\text{hr}} \times \frac{0.564 \text{ kg CH}_4}{\text{kg TOC}} \times \frac{\text{tonne CH}_4}{1000 \text{ kg CH}_4} \times \frac{8760 \text{ hr}}{\text{yr}}$$

$$\underline{E_{CH_4} = 0.47 \text{ tonne CH}_4\text{/yr}}$$

7.3.2 Natural Gas Transmission and Storage

7.3.2.1 Facility Level

As described previously, applying average facility-level emission factors is the simplest method for estimating CH_4 emissions from oil and gas operations, appropriate for use only when no data is available from leak screening or component counts. Facility-level emission factors for Natural Gas Transmission and Storage operations are presented in Table 7-45. Example calculations in Exhibit 7-1 demonstrate the use of facility-level average emission factors.

Table 7-45. Facility-Level Average Fugitive Emission Factors for Natural Gas Transmission and Storage

Source	Emission Factor Original Units	Uncertainty [a] (± %)	Gas Content Basis of Factor	Methane Emission Factor [b] Converted Units to Tonnes	Emission Factor Converted to Whole Gas [c]
Gas storage stations [d, e]	1,491,936 lb CH_4/station-yr	74.7	93.4 mole % CH_4	676.7 tonnes CH_4/station-yr	37,867,460 scf gas/station-yr
Transmission compressor station [f]	64,000 kg CH_4/station-yr	Not specified	93.4 mole % CH_4	64 tonnes CH_4/ station-yr	3,581,209 scf gas/station-yr
Storage compressor station [f]	71,000 kg CH_4/station-yr	Not specified	93.4 mole % CH_4	71 tonnes CH_4/ station-yr	3,972,904 scf gas/station-yr
Gas transmission pipeline systems, including compressor stations, farm taps and sales interconnects					
CH_4 from pipeline systems, includi compressor station leaks [d, e, g]	7,928 lb CH_4/mile-yr	113	93.4 mole % CH_4	3.596 tonnes CH_4/mile-yr	201,224 scf gas/mile-yr
				2.235 tonnes CH_4/km-yr	125,035 scf gas/km-yr
CO_2 from pipeline leak oxidation [d, e, g, h]	7.59 lb CO_2/mile-yr	70.3	2 mole % CO_2	3.443E-03 tonnes CO_2/mile-yr	Not applicable
				2.140E-03 tonnes CO_2/km-yr	
CO_2 from pipeline systems, including compressor station leaks [d, e, g, i]	466.0 lb CO_2/mile-yr	113	2 mole % CO_2	0.2114 tonnes CO_2/mile-yr	201,224 scf gas/mile-yr
				0.1313 tonnes CO_2/km-yr	125,035 scf gas/km-yr

Footnotes and Sources:

[a] Uncertainty is based on a 95% confidence interval from the data used to develop the original emission factor.

[b] The emission factors can be adjusted based on the relative concentrations of CH_4 and CO_2 to estimate CO_2 emissions.

[c] Emission factors converted to whole gas based on 60 °F and 14.7 psia

[d] 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.

[e] See full derivation in Appendix C, Sections C.3.5.

[g] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, Final Report, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[h] A portion of CH_4 emitted from underground pipeline leaks is oxidized to form CO_2.

[i] Combines CO_2 emissions from equipment and pipleines based on a concentration of 2 mole % CO_2 in the pipeline gas.

In addition to CH_4, CO_2 also may be released from fugitive sources if CO_2 is present in the gas stream. Fugitive emission factors specific to CO_2 are limited in current, publicly available studies. As an approximation, the CH_4 emission factor can be adjusted to account for the CO_2 composition of the gas for fugitive sources other than underground pipelines. This conversion is shown in Section 7.2.1.1 and Exhibit 7-1.

Fugitive emissions from natural gas pipelines originate from two sources: (1) gas leaks that result in CH_4 and CO_2 emissions in proportion to the gas composition and (2) the partial oxidation of CH_4 as it migrates through the soil. The degree of oxidation depends on factors such as the depth of cover, soil composition, and leak rate, which is a function of pipeline material. Both types of CO_2 emissions are shown in the tables in this subsection.

Oxidation rates for different soil characteristics and fugitive leak rates for different pipeline materials (cast iron, protected steel, unprotected steel, copper, and plastic) were measured as part of the GRI/EPA U.S. methane emissions study (Campbell, et al., 1996). Equations 7-12 through 7-14 were used in developing the CO_2 emission factors for pipeline fugitive emissions. Equation 7-12 accounts for the portion of leaked CH_4 that is not oxidized to CO_2.

$$\mathrm{EF_{CH_4}} = \left(\text{Total CH}_4\text{ leaked}\right)\times\left(100-\%\text{ Soil Oxidation}\right) \qquad \text{(Equation 7-12)}$$

where

$\mathrm{EF_{CH_4}}$ = emission factor for CH_4 emissions from pipeline fugitive leaks.

Equation 7-13 accounts for the CO_2 formed from the oxidation of leaked CH_4 as the gas migrates through the soil.

$$\mathrm{EF_{CO_2,\,Oxid.}} = \mathrm{EF_{CH_4}}\times\left(\frac{100}{100\text{-}\%\text{ Soil Oxidation}}\right)\times\left(\frac{\%\text{ Soil Oxidation}}{100}\right)\times\left(\frac{\text{MW CO}_2}{\text{MW CH}_4}\right) \qquad \text{(Equation 7-13)}$$

where

$\mathrm{EF_{CO_2,\,Oxid}}$ = emission factor for CO_2 emissions from methane oxidation of leaked CH_4;

$\left(\frac{100}{100\text{-}\%\text{ Soil Oxidation}}\right)$ = CH_4 emission factor correction to its "pre-oxidized" form;

$\left(\frac{\%\text{ Soil Oxidation}}{100}\right)$ = conversion from total moles of CH_4 to moles of CO_2 formed as a result of oxidation; and

$\left(\frac{\text{MW CO}_2}{\text{MW CH}_4}\right)$ = conversion from molar basis to mass basis.

Equation 7-14 accounts for CO_2 that is emitted from pipeline fugitive leaks. This equation starts with the CH_4 emission factor, which is converted to its "pre-oxidized" form by the second term. The third term corrects for the molar ratio of CO_2 to CH_4 in the default gas composition, and the final term corrects for the molecular weights of CO_2 and CH_4.

$$\mathrm{EF}_{\mathrm{CO_2,\,Leak}} = \mathrm{EF}_{\mathrm{CH_4}} \times \left(\frac{100}{\text{100-\% Soil Oxidation}}\right) \times \left(\frac{\text{default mole\% CO}_2}{\text{default mole\% CH}_4}\right) \times \left(\frac{\text{MW CO}_2}{\text{MW CH}_4}\right) \qquad \text{(Equation 7-14)}$$

where

$\mathrm{EF}_{\mathrm{CO_2,\,Leak}}$ = emission factor for CO_2 emissions from pipeline fugitive leaks; and

$\left(\frac{\text{default mol\% CO}_2}{\text{default mol\% CH}_4}\right)$ = conversion from total moles of CH_4 to moles of CO_2, based on default molar concentrations for the gas.

The emission factors shown in Tables 7-46 through 7-49, 7-64, 7-65, and 7-67 are based on average emission rates for the types of pipelines in service in each industry sector. The fugitive emission factors are based on default, average compositions. The default CH_4 or CO_2 content provided in Table D-4 can be replaced with a user-specified gas analysis. In this case, the fugitive emission estimates are adjusted by the ratio of the specified gas CH_4 or CO_2 concentration to the default CH_4 or CO_2 concentration provided in Table D-4. This correction is demonstrated in Exhibit 7-1.

7.3.2.2 Equipment Level

The equipment-level average emission factor approach allows the fugitive emission estimate to be tailored to a particular facility based on the population of major equipment at the facility. This approach of aggregating individual components into major equipment systems may be appropriate when component- and screening-level data is not available. Exhibit 7-4 presents an example of calculating CH_4 emissions using the major equipment emission factors approach.

Most of these major equipment emission factors are CH_4-specific. The default CH_4 concentration for the transmission and storage sector is 93.4 mole %, which is indicated in the table footnotes. Carbon dioxide emissions from buried pipelines are based on an assumed concentration of 2 mole %. The emission factors can be adjusted to other CH_4 concentrations by the ratio of the actual CH_4 content to the default value. In addition, in the absence of CO_2-specific emission factors, CO_2 emissions can be approximated from the CH_4 emission factors based on the ratio of CO_2 to CH_4 in the produced gas. These adjustments are demonstrated in Section 7.2.1.1. Table 7-46 below provides equipment level emission factors for equipment associated with natural gas transmission and storage operations.

Table 7-46. Equipment-Level Emission Factors for Natural Gas Transmission and Storage Equipment

Equipment Basis	Reference Emission Factor, Original Units		Uncertainty [a] (± %)	Gas Content Basis of Factor	Emission Factor [b], Converted to Tonnes		Emission Factor, Converted to Whole Gas [b, c]	
Compressor stations [d, e]	8,778	scf CH_4/ station-day	126	93.4 mole % CH_4	7.02E-03	tonne CH_4/station-hr	3.43E+06	scf gas/ station-yr
Compressor stations – reciprocating compressor [d, e]	15,205	scf CH_4/ compressor-day	84.2		1.22E-02	tonne CH_4/compressor-hr	5.94E+06	scf gas/ compressor-yr
Compressor stations – centrifugal compressor [d, e]	30,305	scf CH_4/ compressor-day	45.7		2.42E-02	tonne CH_4/compressor-hr	1.18E+07	scf gas/ compressor-yr
Meter/Reg. stations [d, e, f]	60,011	scf CH_4/station-yr	1,500 [g]		1.31E-04	tonne CH_4/station-hr	6.43E+04	scf gas/ station-yr
M&R stations – farm taps or direct sales [d, e]	31.2	scf CH_4/ station-day	97.6		2.49E-05	tonne/station-hr	1.22E+04	scf gas/ station-yr
M&R stations – transmission interconnects [d, e]	3,984	scf CH_4/ station-day	96.1		3.18E-03	tonne/station-hr	1.56E+06	scf gas/ station-yr
CH_4 from pipeline leaks [m]	11	kg CH_4/mile-yr	Not specified		1.1E-02	tonnes CH_4/mile-yr	611	scf gas/mile-yr

Equipment Basis	Reference Emission Factor, Original Units		Uncertainty [a] (± %)	Gas Content Basis of Factor	Emission Factor [b], Converted to Tonnes		Emission Factor, Converted to Whole Gas [b, c]	
					6.8E-03	tonnes CH$_4$/km-yr	380	scf gas/km-yr
Gas transmission pipeline [d, e, f]	23.12	lb CH$_4$/mile-yr	94.7		1.20E-06	tonne CH$_4$/mile-hr	586.8	scf gas/mile-yr
					7.44E-07	tonne CH$_4$/km-hr	364.6	scf gas/km-yr
CO$_2$ from oxidation [d, e, f, h]	7.59	lb CO$_2$/mile-yr	70.3	2 mole % CO$_2$	3.93E-07	tonne CO$_2$/mile-hr	Not Applicable	
					2.44E-07	tonne CO$_2$/km-hr		
CO$_2$ from pipeline leaks [f]	1.52	lb CO$_2$/mile-yr	90.1	2 mole % CO$_2$	7.88E-08	tonne CO$_2$/mile-hr	655	scf gas/mile-yr
					4.89E-08	tonne CO$_2$/km-hr	407	scf gas/km-yr
Storage stations [d, e]	21,507	scfd CH$_4$/station	132	93.4 mole % CH$_4$	1.72E-02	tonne CH$_4$/station-hr	8.40E+06	scf gas/yr-station
Storage – reciprocating compressor [d, e]	21,116	scfd CH$_4$/comp.	60.4		1.69E-02	tonne CH$_4$/compressor-hr	8.25E+06	scf gas/yr-compressor
Storage – centrifugal compressor [d, e]	30,573	scfd CH$_4$/comp.	39.0		2.44E-02	tonne CH$_4$/ compressor-hr	1.19E+07	scf gas/yr-compressor

Equipment Basis	Reference Emission Factor, Original Units		Uncertainty [a] (± %)	Gas Content Basis of Factor	Emission Factor [b], Converted to Tonnes		Emission Factor, Converted to Whole Gas [b, c]	
Storage wells [d, e]	114.5	scfd CH_4/well	76.0		9.15E-05	tonne CH_4/well-hr	4.47E+04	scf gas/well-yr
Storage wellhead [i, j]	0.349	tonnes CH_4/ wellhead-yr	Not specified		0.349	tonnes CH_4/ wellhead-yr	1.95E+04	scf gas/well-yr
Centrifugal Compressor - Wet seal [k, l]	68	Mg CH_4/ compressor-yr	42		68	tonnes CH_4/ compressor-yr	3.81E+06	scf gas/ compressor-yr
Centrifugal Compressor - Dry seal [k, l]	41	Mg CH_4/ compressor-yr	33		41	tonnes CH_4/ compressor-yr	2.29E+06	scf gas/ compressor-yr
Reciprocating Compressor [k, l]	64	Mg CH_4/ compressor-yr	28		64	tonnes CH_4/ compressor-yr	3.58E+06	scf gas/ compressor-yr

Footnotes and Sources:

[a] Uncertainty is based on a 95% confidence interval from the data used to develop the original emission factor.

[b] Emission factors converted from scf are based on 60 °F and 14.7 psia. The average CH_4 concentration associated with these emission factors provided in Table D-4 is 93.4 mole %; the average CO_2 concentration (for buried pipelines) also provided in Table D-4 is 2 mole %. If the actual concentration differs from the default value, the emission factors shown above can be adjusted by the ratio of the site concentration to the default concentration.

[c] Conversion from time basis of per day to per year assumes 365 days of operation.

[d] 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.

[e] Campbell, L.M. and B.E. Stapper. *Methane Emissions from the Natural Gas Industry, Volume 10: Metering and Pressure Regulating, Stations in Natural Gas, and Transmission and Distribution, Final Report*, GRI-94/0257.27 and EPA-600/R-96-080j. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[f] Emission factor derivation is provided in Appendix C, Section C.3.5.

[g] Uncertainty range (0 – 900,158 scf CH_4/station-yr).

[h] A portion of CH_4 emitted from underground pipeline leaks is oxidized to form CO_2.

[i] Jeff Kuo, Travis C. Hicks, Brian Drake & Tat Fu Chan (2015) Estimation of methane emission from California natural gas industry, Journal of the Air & Waste Management Association, 65:7, 844-855, DOI: 10.1080/10962247.2015.102592.
[j] This emission factor is specific to California.
[k] Zimmerle, David, et al., Methane Emissions from the Natural Gas Transmission and Storage System in the United States. Environmental Science & Technology, https://doi.org/10.1021/acs.est.5b01669. July 2015.
[l] These emission factors only include major compressor components, including seals/rod packing, isolation valves, and blowdown vent value emissions.
[m] EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 – 2017. 2019. These values were calculated using 2017 year-specific GHGRP Subpart W data by region. Note: These factors, used in the USEPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 – 2017 (EPA, 2019), are updated annually based on data reported from operators under the GHGRP.

Note that the compressor seal emission factors are also included in Section 6 for venting, as they are typically categorized as vented sources, but are repeated in this table for completeness (i.e., to avoid data gaps in reporting).

Table 7-47 provides more detailed pipeline leak emission factors for transmission pipelines that include both CH_4 and CO_2 emissions. The derivation of these emission factors is provided in Appendix C, Section C.3.5.

Table 7-48 provides emission factors for plastic pipelines disaggregated on the basis of whether the pipes were manufactured before or after 1982. These emission factors are provided on both a leak basis and pipeline mileage basis. More detailed information on the derivation of these factors are provided in Appendix C, Section C.3.7.

Table 7-47. More Detailed Fugitive Emission Factors for Natural Gas Transmission Equipment

Source	Emission Factor [a, b], Original Units		Uncertainty [c] (± %)	Gas Content Basis of Factor	Emission Factor [d], Converted Units		Emission Factor, Converted to Whole Gas [e]	
Cast iron pipeline	10,096	lb CH_4/mile-yr	77.0	93.4 mole % CH_4	4.5794	tonne CH_4/mile-yr	2.56E+05	scf gas/mile-yr
					2.8455	tonne CH_4/km-yr	1.59E+05	scf gas/km-yr
CO_2 from oxidation [f]	18,699	lb CO_2/mile-yr	81.0	2 mole % CO_2	8.4817	tonne CO_2/mile-yr	Not Applicable	
					5.2703	tonne CO_2/km-yr		
CO_2 from pipeline leaks	993.6	lb CO_2/mile-yr	81.1	2 mole % CO_2	0.4507	tonne CO_2/mile-yr	4.28E+05	scf gas/mile-yr
					0.2800	tonne CO_2/km-yr	2.66E+05	scf gas/km-yr
Plastic pipeline	22.55	lb CH_4/mile-yr	233	93.4 mole % CH_4	0.01023	tonne CH_4/mile-yr	572	scf gas/mile-yr
					0.00636	tonne CH_4/km-yr	356	scf gas/km-yr
CO_2 from oxidation [f]	1.263	lb CO_2/mile-yr	234	2 mole % CO_2	0.0005728	tonne CO_2/mile-yr	Not Applicable	
					0.0003559	tonne CO_2/km-yr		
CO_2 from pipeline leaks	1.352	lb CO_2/mile-yr	234	2 mole % CO_2	0.0006133	tonne CO_2/mile-yr	583	scf gas/mile-yr
					0.0003811	tonne CO_2/km-yr	362	scf gas/km-yr
Protected steel pipeline	15.16	lb CH_4/mile-yr	139	93.4 mole % CH_4	0.006874	tonne CH_4/mile-yr	385	scf gas/mile-yr

Source	**Emission Factor [a, b], Original Units**		**Uncertainty [c] (± %)**	**Gas Content Basis of Factor**	**Emission Factor [d], Converted Units**		**Emission Factor, Converted to Whole Gas [e]**	
					0.004272	tonne CH_4/km-yr	239	scf gas/km-yr
CO_2 from oxidation [f]	1.286	lb CO_2/mile-yr	141	2 mole % CO_2	0.0005833	tonne CO_2/mile-yr	Not Applicable	
					0.0003625	tonne CO_2/km-yr		
CO_2 from pipeline leaks	0.9180	lb CO_2/mile-yr	141	2 mole % CO_2	0.0004164	tonne CO_2/mile-yr	396	scf gas/mile-yr
					0.0002587	tonne CO_2/km-yr	246	scf gas/km-yr
Unprotected steel pipeline	275.9	lb CH_4/mile-yr	146	93.4 mole % CH_4	0.1251	tonne CH_4/mile-yr	7,003	scf gas/mile-yr
					0.0778	tonne CH_4/km-yr	4,351	scf gas/km-yr
CO_2 from oxidation [f]	13.87	lb CO_2/mile-yr	148	2 mole % CO_2	0.006293	tonne CO_2/mile-yr	Not Applicable	
					0.003910	tonne CO_2/km-yr		
CO_2 from pipeline leaks	16.51	lb CO_2/mile-yr	148	2 mole % CO_2	0.007487	tonne CO_2/mile-yr	7,116	scf gas/mile-yr
					0.004652	tonne CO_2/km-yr	4,422	scf gas/km-yr

Footnotes and Sources

[a] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines, Final Report*, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[b] Emission factor derivations are provided in Appendix C, Section C.3.5.

[c] Uncertainty based on a 95% confidence interval from the data used to develop the original emission factor.

[d] The average CH_4 concentration associated with these emission factors provided in Table D-4 is 93.4 mole %; the average CO_2 concentration (for buried pipelines) also provided in Table D-4 is 2 mole %. If the actual concentration differs from the default value, the emission factors shown above can be adjusted by the ratio of the site concentration to the default concentration.

[e] Emission factors converted to scf are based on 60 °F and 14.7 psia.

[f] A portion of CH_4 emitted from underground pipeline leaks is oxidized to form CO_2.

Table 7-48. Fugitive Emission Factors from Underground Plastic Pipelines by Construction Year In Transmission Sector

Source [a]	**Leak Based Emission Factors** [b, c, d, e]				**Pipeline Length Based Emission Factors** [b, c, d, e]					
	Pre-1982		**Post-1982 (ASTM D2837)**		**Pre-1982**			**Post-1982 (ASTM D2837)**		
	(tonnes/leak-yr) [f]	**Uncertainty (± %)** [g]	**(tonnes/leak-yr)** [f]	**Uncertainty (± %)** [g]	**(tonnes/ mi-yr)** [f, h]	**(tonnes/ km-yr)** [f, h]	**Uncertainty (± %)** [g, i]	**(tonnes/ mi-yr)** [f, h]	**(tonnes/ km-yr)** [f, h]	**Uncertainty (± %)** [g, i]
CH_4 from pipeline leaks	0.983	164	0.166	36	0.0053	0.003	249	0.00089	0.001	110
CO_2 from pipeline leaks	0.059	157	0.010	26	0.00031	0.000	241	0.000053	0.000	104
CO_2 from oxidation [j]	0.055	164	0.0093	36	0.00029	0.000	249	0.000050	0.000	110

Footnotes and Sources:

[a] Transmission sector emission factors are based on a gas composition provided in Table D-4 of 93.4 mole % CH4 and 2 mole % CO2. Leak-based emission factors were converted to miles basis using 14 +/- 78.6% equivalent leaks and 2621 +/-10% miles of transmission pipeline from Table 8-7 of Volume 9 of the 1996 GRI/EPA study.

[b] Emission factors derived from data presented in the 1996 GRI/EPA Study and from Southern California Gas Company (SoCal); refer to Appendix C, Section C.3.7, for more details.

[c] Campbell, L. M., M. V. Campbell, and D. L. Epperson. *Methane Emissions from the Natural Gas Industry*, Volume 9: Underground Pipelines, Final Report, GRI-94/0257.26 and EPA 600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[d] Southern California Gas Company (SoCal). *A Study of the 1991 Unaccounted-for Gas Volume at the Southern Gas Company*, April 1993.

[e] The SoCal data were taken from: California Energy Commission (CEC). *Evaluation of Oil and Gas Sector Greenhouse Gas Emissions Estimation and Reporting*, California Energy Commission, Consultant Report, Final Draft, April 14, 2006.

[f] CH_4 emission factors converted from scf or m^3 are based on 60°F and 14.7 psia.

[g] Uncertainty based on 95% confidence interval from the data used to develop the original emission factor.

[h] Leak based emission factors were converted to miles basis based on the leak/miles ratio taken from data presented in Volume 9 of the 1996 GRI/EPA study. Equivalent leaks and pipeline miles were not provided by year of construction, so this conversion was based on the total U.S. leaks and miles of pipeline. Factors were then converted to kilometer basis.

[i] Because the data used to calculate the activity factor for the referenced emission was unavailable, the uncertainty at a 95% confidence interval was calculated from the reported 90% confidence interval assuming a data set size of ten.

[j] A portion of CH_4 emitted from underground pipeline leaks is oxidized to form CO_2. The conversion in the table above was based on 2.0% (± 25%) soil oxidation for plastic pipelines taken from Table 8-2 of Volume 9 of the GRI/EPA study.

7.3.2.3 Component Level – Average Emission Factors

The component-level average emission factor approach is based on the number of components in the facility. Where no monitoring data is available, this approach provides a more accurate estimation than equipment or facility level emission factors, since it is based on site-specific component population data. This methodology requires component counts; however, if this information is not available generic counts can be obtained as detailed in Appendix C, Section C.1.2.

Details on the methodologies and equations used to estimate TOC mass emissions for a given component type are included in Section 7.2.1.3. An example calculation illustrating the use of component-level fugitive emission factors is provided in Exhibit 7-2.

Table 7-49 provides natural gas transmission compressor station average component-level emission factors for main line pressure (500-1000 psi) and fuel gas pressure (70 – 100 psi) as determined for components located on and off compressors (Howard, et al., 1999). The emission factors are based on leak rate measurements taken at 13 compressor stations in the U.S. and Canada from 1995 to 1997.

Table 7-49. Natural Gas Transmission Compressor Station Average Component-Level Emission Factors

Component	**ON COMPRESSOR**			**OFF COMPRESSOR**		
	Reference Emission Factor [a], Original Units, Mcf gas/ component-yr	**Uncertainty [b] (± %)**	**Emission Factor [c], Converted to tonne CH_4/ component-hr**	**Reference Emission Factor [a], Original Units, Mcf gas/ component-yr**	**Uncertainty [b] (± %)**	**Emission Factor [c], Converted to tonne CH_4/ component-hr**
MAIN LINE PRESSURE (500 to 1000 psi)						
Ball/Plug Valves	0.64	163	1.31E-06	5.33	70	1.09E-05
Blowdown Valves	--	--	--	207.5	83	4.24E-04
Compressor Cylinder Joints	9.9	112	2.02E-05	--	--	--
Packing Seals - Running	865	29	1.77E-03	--	--	--
Packing Seals - Idle	1266	44	2.59E-03	--	--	--
Compressor Valves	4.1	93	8.39E-06	--	--	--
Control Valves	--	--	--	4.26	167	8.71E-06
Flanges	0.81	110	1.66E-06	0.32	66	6.54E-07

Component	ON COMPRESSOR			OFF COMPRESSOR		
	Reference Emission Factor [a], Original Units, Mcf gas/ component-yr	**Uncertainty [b] (± %)**	**Emission Factor [c], Converted to tonne CH_4/ component-hr**	**Reference Emission Factor [a], Original Units, Mcf gas/ component-yr**	**Uncertainty [b] (± %)**	**Emission Factor [c], Converted to tonne CH_4/ component-hr**
Gate Valves	--	--	--	0.61	70	1.25E-06
Loader Valves	17.2	33	3.52E-05	--	--	--
Open-Ended Lines (OEL)	--	--	--	81.8	97	1.67E-04
Pressure Relief Valves (PRV)	--	--	--	57.5	110	1.18E-04
Regulators	--	--	--	0.2	105	4.09E-07
Starter Gas Vents	--	--	--	40.8	106	8.34E-05
Threaded Connectors	0.74	62	1.51E-06	0.6	50	1.23E-06
Centrifugal Seals - Dry	--	--	--	62.7	106	1.28E-04
Centrifugal Seals - Wet	--	--	--	278	--	5.69E-04
Unit Valves	--	--	--	3566	--	7.29E-03
FUEL GAS PRESSURE (70 to 100 psi)						
Ball/Plug Valves	0.1	100	2.05E-07	0.51	73	1.04E-06
Control Valves	--	--	--	2.46	158	5.03E-06
Flanges	--	--	--	0.2	95	4.09E-07
Fuel Valves	27.6	49	5.64E-05	--	--	--
Gate Valves	--	--	--	0.43	84	8.79E-07
Open-Ended Lines (OEL)	--	--	--	2.53	87	5.17E-06
Pneumatic Vents	--	--	--	76.6	154	1.57E-04
Regulators	--	--	--	4.03	99	8.24E-06
Threaded Connectors	1.21	137	2.47E-06	0.32	50	6.54E-07

Footnotes and Sources:

[a] Howard, T., R. Kantamaneni, and G. Jones. *Cost Effective Leak Mitigation at Natural Gas Transmission Compressor Stations*, *Final Report*. PRC International, Gas Research Institute, and U.S. EPA Natural Gas STAR Program, August 1999, Tables 3 and 4.

[b] Uncertainty based on 95% confidence interval from the data used to develop the original emission factor.

[c] Emission factors converted from scf are based on 60°F and 14.7 psia. The total gas emission factors were converted to a CH_4 basis assuming a default CH_4 concentration associated with the transmission sector of 93.4 mole % (provided in Table D-4).

Table 7-50 provides average component-level emission factors and uncertainty values based on data developed in Canada (Picard, 1998).

Table 7-50. Natural Gas Transmission and Storage Average Component-Level Emission Factors

Component	Emission Factor [a], kg THC/hr/comp.	Emission Factor, tonne TOC/component-hr	Uncertainty [b, c] (± %)
Block valves	0.002140	2.14E-06	40.1
Control valves	0.01969	1.97E-05	70.2
Connectors	0.0002732	2.73E-07	19.0
Compressor seals – reciprocating	0.6616	6.62E-04	38.9
Compressor seals – centrifugal	0.8139	8.14E-04	71.5
Pressure relief valves	0.2795	2.80E-04	127
Open-ended lines (OEL)	0.08355	8.36E-05	53.0
OEL - station or pressurized compressor blowdown system [d]	0.9369	9.37E-04	61.6
OEL – depressurized reciprocating (comp. blowdown system)	2.347	2.35E-03	67.6
OEL – depressurized centrifugal (comp. blowdown system)	0.7334	7.33E-04	103
OEL – overall pressurized/ depressurized reciprocating [e] (comp. blowdown system)	1.232	1.23E-03	Not available
OEL – overall pressurized/ depressurized centrifugal [e] (comp. blowdown system)	0.7945	7.94E-04	Not available
Orifice meter	0.003333	3.33E-06	40.6
Other gas meter	9.060E-06	9.06E-09	116

Footnotes and Sources:

[a] D.J.Picard, M. Stribrny, and M.R. Harrison. *Handbook for Estimating Methane Emissions from Canadian Natural Gas Systems*. GTC Program #3. Environmental Technologies, May 25, 1998, Table 4.

[b] Uncertainty based on 95% confidence interval from the data used to develop the original emission factor.

[c] Original emission factors were presented with upper and lower confidence limits. To be conservative, the larger % was chosen to represent the full % uncertainty of the mean value.

[d] The compressor type is not specified. The emission factor is assumed to apply to either reciprocating or centrifugal compressor types or stations.

[e] Overall OEL average emission factors that account for the time that the compressor unit is pressurized and depressurized during the year have been estimated using the annual fractions of the modes of operation taken from Table 4-20 of Volume 8 of the GRI/EPA methane emissions study (Hummel, et al., 1996). The percentages from the GRI/EPA study are 79.1% pressurized/20.9% depressurized for reciprocating compressors and 30% pressurized/70% depressurized for centrifugal compressors. Therefore, these percentages were applied to the base pressurized and depressurized emission factors provided in the table above to develop overall factors that represent annual average emission factors converted to an hourly basis.

Table 7-51 and Table 7-52 provide average component-level emission factors for the natural gas transmission and storage sectors, respectively, that are specific to California (Kuo, 2015).

Table 7-51. Natural Gas Transmission Sector Average Component-Level Emission Factors: California Specific

Component	Emission Factor [a], tonnes CH_4/ component-yr	Uncertainty (± %)	Gas Content Basis of Factor (mole % CH_4)	Converted Whole Gas Emission Factor, scf gas/ component-yr [b]
Associated Equipment – Piping Segments				
Flanges	1.10E-04	Not specified	93.4	6.16
Manual Valves	1.43E-03			80.0
OELs	1.50E+01			8.39E+05
Threaded Connection	6.36E-04			35.6
Associated Equipment – Reciprocating Compressors				
Flange	4.58E-02	Not specified	93.4	2.56E+03
Manual Valves	2.71E-04			15.2
Seals	1.51E-01			8.45E+03
Threaded Connection	7.42E-04			41.5
Associated Equipment – Centrifugal Compressors				
Flange	1.21E-02	Not specified	93.4	677
Seals	5.94E-01			3.32E+04

Footnotes and Sources:

[a] Jeff Kuo, Travis C. Hicks, Brian Drake & Tat Fu Chan (2015) Estimation of methane emission from California natural gas industry, Journal of the Air & Waste Management Association, 65:7, 844-855, DOI: 10.1080/10962247.2015.102592.

[b] Emission factors converted based on 60°F and 14.7 psia.

Table 7-52. Natural Gas Storage Sector Average Component-Level Emission Factors: California Specific

Component	**Original Emission Factor [a]**		**Uncertainty (± %)**	**Methane Content (mole %)**	**Converted Whole Gas Emission Factor, scf gas/ component-yr [b]**
Associated Equipment – Wellheads					
Manual Valves [c, d]	9.18E-04	scf CH_4/component-min	Not specified	93.4	517
OELs [c, d]	1.05E-03	scf CH_4/component-min			591
Others [c, d]	2.20E-01	scf CH_4/component-min			1.24E+05
Threaded Connection [c, d]	1.28E-04	scf CH_4/component-min			72
Associated Equipment – Separators					
OEL	2.68E-03	tonnes CH_4/component-yr	Not specified	93.4	11
Others	5.83E-03	tonnes CH_4/component-yr			326
Threaded Connection	5.75E-05	tonnes CH_4/component-yr			3
Associated Equipment – Piping Segments					
Flanges	7.23E-04	tonnes CH_4/component-yr	Not specified	93.4	40
Manual Valves	2.12E-04	tonnes CH_4/component-yr			12
OELs	1.09E-03	tonnes CH_4/component-yr			61
PRV	2.43E-01	tonnes CH_4/component-yr			1.36E+04
Regulators	4.59E-01	tonnes CH_4/component-yr			2.57E+04
Threaded Connection	6.45E-04	tonnes CH_4/component-yr			36
Associated Equipment – Reciprocating Compressors					
Manual Valves	1.62E-03	tonnes CH_4/component-yr	Not specified	93.4	91
Associated Equipment – Centrifugal Compressors					
Manual Valves	8.04E-03	tonnes CH_4/component-yr	Not specified	93.4	450
Threaded Connection	4.14E-04	tonnes CH_4/component-yr			23

Footnotes and Sources:

[a] Jeff Kuo, Travis C. Hicks, Brian Drake & Tat Fu Chan (2015) Estimation of methane emission from California natural gas industry, Journal of the Air & Waste Management Association, 65:7, 844-855, DOI: 10.1080/10962247.2015.102592.

[b] Emission factors converted based on 60°F and 14.7 psia.

[c] Study does not reference temperature and pressure associated with factors, so here it is assumed that cfm is equivalent to scfm.

[d] Emission factor conversion to whole gas assumes 8760 hours of operation.

Table 7-53 presents average component-level emission factors for the transmission and storage sector compressor stations (Subramanian, 2015).

Table 7-53. Natural Gas Transmission and Storage Compressor Station Average Component-Level Emission Factors

Component	Original Emission Factor [a, b], scf CH_4/ component-min	Uncertainty (± %)	Gas Content (mole % CH_4)	Converted Whole Gas Emission Factor, scf gas/ component-yr [c, d]
Associated Equipment – Reciprocating Compressor				
Blowdown Valve – Operating mode	5.2	Not specified	93.4	2.93E+06
Blowdown Valve – Standby pressurized mode	2			1.13E+06
Associated Equipment – Centrifugal Compressor				
Blowdown Valve – Operating mode	5.4	Not specified	93.4	3.04E+06
Blowdown Valve – Standby pressurized mode	0			0.0
Associated Equipment – Compressor Components				
Connector	0.2	Not specified	93.4	1.13E+05
Valve	0.2			1.13E+05
Open ended line	1.7			9.57E+05
PRV	0.1			5.63E+04
Meter	0.1			5.63E+04
Associated Equipment – Non-compressor Components				
Connector	0.2	Not specified	93.4	1.13E+05
Valve	0.2			1.13E+05
Open ended line	0.5			2.81E+05
PRV	0.3			1.69E+05
Meter	0.03			1.69E+04

Footnotes and Sources:

[a] Subramanian, R, et al., (2015) *Methane Emissions from Natural Gas Compressor Stations in the Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol*, Environmental Science & Technology, 49, 5, 3252–3261, https://doi.org/10.1021/es5060258.

[b] Compressor fugitive emissions are restricted to emissions from major compressor equipment (unit isolation valves, blowdown valves, shaft seals, rod packing vents).

[c] Emission factors converted based on 60°F and 14.7 psia.

[d] Emission factor conversion to whole gas assumes 8,760 hours of operation.

Table 7-54 contains average component-level emission factors for the natural gas storage sector, specifically for underground storage wellheads (EPA Subpart W, 2019).

Table 7-54. Underground Natural Gas Storage Wellhead Component-Level Emission Factors

Component	Original Emission Factor [a], scf THC/component-hr	Uncertainty (± %)
Connector	0.01	Not specified
Valve	0.1	
Pressure Relief Valve	0.17	
Open-Ended Line	0.03	

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (USEPA), 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Table W-4B. Data reported as of August 2, 2019. https://ecfr.io/Title-40/sp40.23.98.w.

7.3.2.4 Component Level – Leaker Factors

OGI leaker factors are used to estimate emissions from facilities using OGI to screen for leaking components. Using this approach, the facility only needs to know the number of leaks by component type. Using Equation 7-9 from Section 7.2.2.4, and converting to mass units using Equation 6-2, facilities can calculate the mass emission rate of CH_4 and CO_2 using the emission factors presented in the tables below.

Table 7-55 below provides whole gas leaker factors for the Transmission and Storage sector, specifically related to compressor and non-compressor components (Zimmerle, 2015). Note that the rod packing vent is also included in the Section 6 venting chapter, but is repeated here for completeness (i.e., to avoid data gaps in reporting emissions from compressors).

Table 7-55. Whole Gas Leaker Factors for Transmission and Storage

Component	Original Units, scf gas/ component-hr [a]	Uncertainty (± %) [b]	Methane Content (mole %)	Emission Factor, Converted to scf CH_4/component-hr
Compressor Components				
Connector - Flanged	21.2	99.7	93.4	19.8
Connector - Threaded	21.2	99.7		19.8
Valve	12.2	95.4		11.4
PRV	22.6	97.4		21.1
OEL	143	100		133.6
Other [c]	22.6	97.4		21.1
Rod Packing Vent	219	100		204.5
Blowdown Vent	76.4	100		71.4
Non-compressor Components				
PRV	22.6	97.4	93.4	21.1
Connector - Flanged	9.87	99.4		9.2
Connector - Threaded	12	100.0		11.2
Valve	12	100.0		11.2
Other [c]	22.6	97.4		21.1
OEL	143	97.4		133.6

Footnotes and Sources:

[a] Zimmerle, David, et al., Methane Emissions from the Natural Gas Transmission and Storage System in the United States. Environmental Science & Technology, https://doi.org/10.1021/acs.est.5b01669. July 2015.

[b] Uncertainty was presented in terms of upper and lower limits, the largest was chosen to be conservative.

[c] Other is not specified between compressor and non-compressor so it is assumed the emission factor is applicable to both.

Leaker emission factors for onshore natural gas transmission compression are presented in Table 7-56 from 40 CFR 98, Subpart W, "Mandatory Greenhouse Gas Reporting – Petroleum and Natural Gas Systems." These factors can be used if leak surveys have been completed using OGI cameras or Method 21 surveys conducted at a leak threshold of 10,000 ppmv. [4] The leaker factors in Table 7-56 are only applied to the leaking components identified during the leak survey.

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[4] In accordance with GHGPR Subpart W CFR§98.234(a)(1)-(6).

Table 7-56. Default THC Leaker Emission Factors for Onshore Natural Gas Transmission Compression: Surveys using OGI Screening or Method 21 Surveys at 10,000 ppmv Leak Detection Threshold

Component [a]	ON COMPRESSOR		OFF COMPRESSOR	
	Original Units, scf THC/hr/comp.	Uncertainty (± %)	Original Units, scf THC/hr/comp.	Uncertainty (± %)
Service Type – Gas Service				
Valve [b]	14.84	Not specified	6.42	Not specified
Connector	5.59		5.71	
Open-Ended Line	17.27		11.27	
Pressure Relief Valve	39.66		2.01	
Meter or Instrument	19.33		2.93	
Other [c]	4.1		4.1	

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (USEPA), 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Table W-3A. Data reported as of August 2, 2019. https://ecfr.io/Title-40/sp40.23.98.w.

[b] Valves include control valves, block valves, and regulator valves.

[c] Other includes any potential equipment leak emission point in gas service that is not specifically listed in this table, as specified in 98.232(e)(8).

Table 7-57 contains emission factors that can be used if surveys have been completed based on Method 21 with a leak detection threshold of 500 ppmv[5] in natural gas transmission compression stations (EPA GHGRP, 2019).

Table 7-57. Default THC Leaker Emission Factors for Onshore Natural Gas Transmission Compression: Method 21 Surveys at 500 ppmv Leak Detection Threshold

Component [a]	ON COMPRESSOR		OFF COMPRESSOR	
	Original Units, scf THC/hr/comp.	Uncertainty (± %)	Original Units, scf THC/hr/comp.	Uncertainty (± %)
Service Type – Gas Service				
Valve [b]	9.51	Not specified	4.12	Not specified
Connector	3.58		3.66	

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[5] In accordance with 40 CFR §98.234(a)(7) of the GHGRP.

Component [a]	ON COMPRESSOR		OFF COMPRESSOR	
	Original Units, scf THC/hr/comp.	Uncertainty (± %)	Original Units, scf THC/hr/comp.	Uncertainty (± %)
Open-Ended Line	11.07		7.22	
Pressure Relief Valve	25.42		1.29	
Meter or Instrument	12.39		1.88	
Other [c]	2.63		2.63	

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (USEPA), 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Table W-3A. Data reported as of August 2, 2019. https://ecfr.io/Title-40/sp40.23.98.w.

[b] Valves include control valves, block valves, and regulator valves.

[c] Other includes any potential equipment leak emission point in gas service that is not specifically listed in this table, as specified in 98.232(e)(8).

Leaker emission factors for underground natural gas storage stations are presented in Table 7-58 and were obtained from 40 CFR 98, Subpart W, “Mandatory Greenhouse Gas Reporting – Petroleum and Natural Gas Systems.” These factors can be used if surveys have been completed[6] using OGI cameras or Method 21 surveys conducted at a leak threshold of 10,000 ppmv.

Table 7-58. Default THC Leaker Emission Factors for Underground Natural Gas Storage Stations: Surveys using OGI Screening or Method 21 Surveys at 10,000 ppmv Leak Detection Threshold

Component	Original Emission Factor [a], scf THC/hr/comp.	Uncertainty (± %)
Valve [b]	14.84	Not specified
Connector (other)	5.59	
Open-Ended Line	17.27	
Pressure Relief Valve	39.66	
Meter or Instrument	19.33	
Other [c]	4.1	

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (USEPA), 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Table W-4A. Data reported as of August 2, 2019. https://ecfr.io/Title-40/sp40.23.98.w.

[b] Valves include control valves, block valves, and regulator valves.

[c] Other includes any potential equipment leak emission point in gas service that is not specifically listed in this table, as specified in 98.232(f)(6) and (8).

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[6] In accordance with GHGRP Subpart W 40 CFR §98.234(a)(1)-(6),

Table 7-59 contains leaker emission factors for underground natural gas storage stations that can be used if surveys have been completed based on Method 21 with a leak detection threshold of 500 ppmv[7] (EPA GHGRP, 2019).

Table 7-59. Default THC Leaker Emission Factors for Underground Natural Gas Storage Stations: Method 21 Surveys at 500 ppm Leak Detection Threshold

Component	**Original Emission Factor [a], scf THC/hr/comp.**	**Uncertainty (± %)**
Valve [b]	9.51	Not specified
Connector (other)	3.58	
Open-Ended Line	11.07	
Pressure Relief Valve	25.42	
Meter or Instrument	12.39	
Other [c]	2.63	

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (USEPA), 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Table W-4A. Data reported as of August 2, 2019. https://ecfr.io/Title-40/sp40.23.98.w.

[b] Valves include control valves, block valves, and regulator valves.

[c] Other includes any potential equipment leak emission point in gas service that is not specifically listed in this table, as specified in 98.232(f)(6) and (8).

Leaker emission factors for underground natural gas storage wellheads are presented in Table 7-60 and were obtained from 40 CFR 98, Subpart W, "Mandatory Greenhouse Gas Reporting – Petroleum and Natural Gas Systems." These factors can be used if surveys have been completed using OGI cameras and Method 21 surveys[8] conducted at a leak threshold of 10,000 ppmv.

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[7] In accordance with 40 CFR §98.234(a)(7) of the GHGRP.

[8] based on GHGRP Subpart W 40 CFR §98.234(a)(1)-(6)

Table 7-60. Default THC Leaker Emission Factors for Underground Natural Gas Storage Wellheads: Surveys using OGI Screening or Method 21 Surveys at 10,000 ppmv Leak Detection Threshold

Component	Original Emission Factor [a], scf THC/hr/comp.	Uncertainty (± %)
Valve [b]	4.5	Not specified
Connector (other than flanges)	1.2	
Flange	3.8	
Open-ended Line	2.5	
Pressure Relief Valve	4.1	
Other [c]	4.1	

Footnotes and Sources:
[a] U.S. Environmental Protection Agency (USEPA), 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Table W-4A. Data reported as of August 2, 2019. https://ecfr.io/Title-40/sp40.23.98.w.
[b] Valves include control valves, block valves, and regulator valves.
[c] Other includes any potential equipment leak emission point in gas service that is not specifically listed in this table, as specified in 98.232(f)(6) and (8).

Table 7-61 contains leaker emission factors that can be used for underground natural gas storage wellheads if surveys have been completed based on Method 21 with a leak detection threshold of 500 ppmv[9] (EPA GHGRP, 2019).

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[9] as specified in 40 CFR §98.234(a)(7) of the GHGRP

Table 7-61. Default THC Leaker Emission Factors for Underground Natural Gas Storage Wellheads: Method 21 Surveys at 500 ppm Leak Detection Threshold

Component	Original Emission Factor [a], scf THC/hr/comp.	Uncertainty (± %)
Valve [b]	3.2	Not specified
Connector (other than flanges)	0.7	
Flange	2	
Open-Ended Line	1.7	
Pressure Relief Valve	2.5	
Other [c]	2.5	

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (USEPA), 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Table W-4A. Data reported as of August 2, 2019. https://ecfr.io/Title-40/sp40.23.98.w.

[b] Valves include control valves, block valves, and regulator valves.

[c] Other includes any potential equipment leak emission point in gas service that is not specifically listed in this table, as specified in 98.232(f)(6) and (8).

7.3.2.5 Component Level – Screening Range Factors

This document does not cite any component-level screening range factors (i.e., leak / no-leak factors) for natural gas transmission and storage.

7.3.2.6 Correlation Equations Using Method 21 Monitoring

Although there were no transmission and storage segment-specific correlation equations found, the general petroleum industry and natural gas system approaches previously presented can be used. Correlation equations with screening values are presented in Table 7-40 for the petroleum industry, along with default zero factors in Table 7-41 and pegged emission factors in Table 7-42. Correlation equations are presented in Table 7-43 for the California natural gas industry, alongside pegged emission factors in Table 7-44. An example calculation exhibiting the use of component-level screening factors is provided in Exhibit 7-5.

7.3.3 Emissions from CO_2 Transport

Fugitive emissions from the pipeline transport of CO_2, such as for EOR operations, occur in a similar fashion to fugitive emissions from the pipeline transport of natural gas. IPCC provides a methodology to convert CH_4 emission factors on a mass basis to CO_2 emission factors (IPCC, 2006) for CO_2 pipelines. The methodology is based on the pressure drop through a pipe, and is shown in Equation 7-15. The derivation of this equation is provided in Appendix C, Section C.3.8.

$$E_{CO_2} = EF_{CH_4} \times \sqrt{\frac{44}{16}} \qquad \text{(Equation 7-15)}$$

where

$\sqrt{\frac{44}{16}}$ = mass basis CH_4 to CO_2 conversion; and

EF_{CH_4} = CH_4 natural gas pipeline leak emission factor provided earlier in this section.

Equation 7-15 should be applied to estimate CO_2 emissions from CO_2 pipelines. For CO_2-based equipment other than pipelines, CO_2 fugitive emissions can be estimated based on the relevant CH_4 emission factor by applying Equation 7-1.

7.3.4 Natural Gas Distribution

7.3.4.1 Facility Level

As described previously, applying average facility-level emission factors can be used when only pipeline lengths are available for estimating CH_4 emissions from natural gas distribution pipeline systems. Facility-level emission factors for natural gas distribution operations are presented in Table 7-62. Exhibit 7-1 demonstrates the use of facility-level average emission factors.

Table 7-62. Facility-Level Average Fugitive Emission Factors for Natural Gas Distribution

Source [a, b, c]	**Emission Factor, Original Units**		**Uncertainty (± %) [d]**	**Gas Content Basis of Factor**	**Emission Factor, Converted to tonnes [e]**		**Emission Factor, Converted to Whole Gas**	
Gas Distribution Pipelines								
CH_4 from pipeline system leaks	3,557	lb CH_4/mile-yr	62.7	93.4 mole % CH_4	1.613	tonnes CH_4/mile-yr	90,282	scf gas/mile-yr
					1.002	tonnes CH_4/km-yr	56,099	scf gas/km-yr
CO_2 from oxidation [f]	1,236	lb CO_2/mile-yr	76.6	2 mole % CO_2	0.561	tonnes CO_2/mile-yr	Not applicable	
					0.348	tonnes CO_2/km-yr	Not applicable	
CO_2 from pipeline system leaks [g]	235.4	lb CO_2/mile-yr	74.4	2 mole % CO_2	0.107	tonnes CO_2/mile-yr	101,463	scf gas/mile-yr
					0.066	tonnes CO_2/km-yr	63,046	scf gas/km-yr

Footnotes and Sources:

[a] 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.

[b] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas* Industry, *Volume 9: Underground Pipelines*, *Final Report*, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[c] Derivation of emission factors located in Appendix C, Section C.3.6.

[d] Uncertainty is based on a 95% confidence interval from the data used to develop the original emission factor.

[e] The emission factors can be adjusted based on the relative concentrations of CH_4 and CO_2 to estimate CO_2 emissions.

[f] A portion of CH_4 emitted from underground pipeline leaks is oxidized to form CO_2.

[g] Combines CO_2 emissions from equipment and pipelines based on a concentration of 2 mole % CO_2 in the pipeline gas.

In addition to CH_4, CO_2 also may be released from fugitive sources if CO_2 is present in the gas stream. Fugitive emission factors specific to CO_2 are limited in current, publicly available studies. As an approximation, the CH_4 emission factor can be adjusted to account for the CO_2 composition of the gas for fugitive sources other than underground pipelines. This conversion is shown in Section 7.2.1.1 and Exhibit 7-1.

The discussion of fugitive emissions from natural gas pipelines and the development of CO_2 emission factors for pipelines are discussed in Section 7.3.2.1 for natural gas transmission and storage facility-level leaks.

7.3.4.2 Equipment Level

The equipment-level average emission factor approach allows the fugitive emission estimate to be tailored to a particular facility based on the population of major equipment at the facility. The data listed in Table 7-63 was developed from component monitoring and emission measurement data, and was then aggregated using activity data factors that characterized the number of components per major equipment system. Exhibit 7-4 presents an example of calculating CH_4 emissions using the major equipment-level emission factor approach.

Table 7-63 provides equipment-level emission factors for gas distribution equipment. Table 7-64 provides fugitive emission factors for gas distribution M&R stations. These major equipment emission factors are CH_4-specific. The default CH_4 concentration for these emission factor tables provided in Table D-4 is 93.4 mole %. Carbon dioxide emissions from buried pipelines are based on an assumed concentration of 2 mole %. The emission factors can be adjusted for other CH_4 concentrations by the ratio of the actual CH_4 content to the default value. The emission factors can also be used to estimate CO_2 emissions based on the ratio of CO_2 to CH_4 in the produced gas. These adjustments are demonstrated in Section 7.2.1.1.

Table 7-63. Equipment-Level Fugitive Emission Factors for Gas Distribution Equipment

Equipment Basis	Reference Emission Factor [a, b], Original Units		Uncertainty [c] (± %)	Emission Factor [d], Converted to Tonnes		Gas Content (mole %)	Emission Factor, Converted to Whole Gas	
Customer meters [e]	129.15	scf CH_4/meter-yr	24.6	2.83E-07	tonne CH_4/meter-hr	93.4 mole % CH_4	138	scf gas/meter-yr
Commercial/industrial meters	47.9	scf CH_4/meter-yr	47.1	1.05E-07	tonne CH_4/meter-hr		51	scf gas/meter-yr
Residential meters	138.5	scf CH_4/meter-yr	20.6	3.03E-07	tonne CH_4/meter-hr		148	scf gas/meter-yr
Distribution meter/reg. stations [e]	207,018	scf CH_4/station-yr	111	4.53E-04	tonne CH_4/station-hr		221,647	scf gas/ station-yr
Distribution pipelines [e]	1,359	lb CH_4/mile-yr	71.4	7.04E-05	tonne CH_4/mile-hr		34,493	scf gas/mile-yr
				4.37E-05	tonne CH_4/km-hr		21,433	scf gas/km-yr
CO_2 from oxidation [e, f]	1,204	lb CO_2/mile-yr	78.7	6.24E-05	tonne CO_2/mile-hr	2 mole % CO_2	Not applicable	
				3.87E-05	tonne CO_2/km-hr		Not applicable	
CO_2 from pipeline leaks [e]	105.6	lb CO_2/mile-yr	67.7	5.47E-06	tonne CO_2/mile-hr		45,516	scf gas/mile-yr
				3.40E-06	tonne CO_2/km-hr		28,282	scf gas/km-yr
Distribution services (mileage basis) [e]	1,067	lb CH_4/mile-yr	140	5.53E-05	tonne CH_4/mile-hr	93.4 mole % CH_4	27,082	scf gas/mile-yr
				3.43E-05	tonne CH_4/km-hr		16,828	scf gas/km-yr
CO_2 from oxidation [e, f]	54.4	lb CO_2/mile-yr	115	2.82E-06	tonne CO_2/mile-hr	2 mole % CO_2	Not applicable	

Equipment Basis	Reference Emission Factor [a, b], Original Units		Uncertainty [c] (± %)	Emission Factor [d], Converted to Tonnes		Gas Content (mole %)	Emission Factor, Converted to Whole Gas	
				1.75E-06	tonne CO_2/km-hr	2 mole % CO_2	Not applicable	
CO_2 from service leaks [e]	63.9	lb CO_2/mile-yr	140	3.31E-06	tonne CO_2/mile-hr		27,542	scf gas/mile-yr
				2.05E-06	tonne CO_2/km-hr		17,114	scf gas/km-yr
Distribution services (service basis) [e]	12.7	lb CH_4/service-yr	140	6.55E-07	tonne CH_4/service-hr	93.4 mole % CH_4	322	scf gas/service-yr
CO_2 from oxidation [e, f]	0.65	lb CO_2/service-yr	115	3.34E-08	tonne CO_2/service-h	2 mole % CO_2	Not applicable	
CO_2 from service leaks [e]	0.76	lb CO_2/service-yr	140	3.92E-08	tonne CO_2/service-hr		328	scf gas/service-yr

Footnotes and Sources:

[a] 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.

[b] Hummel, K.E., L.M. Campbell, and M.R. Harrison. *Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks*, *Final Report,* GRI-94/0257.1 and EPA-600/R-96-080b. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[c] Uncertainty is based on a 95% confidence interval from the data used to develop the original emission factor.

[d] Emission factors converted from scf are based on 60 deg. F and 14.7 psia. The average CH4 concentration associated with these emission factors provided in Table D-4 is 93.4 mole %; the average CO2 concentration (for buried pipelines) also provided in Table D-4 is 2 mole %. If the actual concentration differs from the default value, the emission factors shown above can be adjusted by the ratio of the site concentration to the default concentration.

[e] Emission factor derivation provided in Appendix C, Section C.3.6. Additional distribution service factors (on a service basis) are presented in Appendix C, Section C.3.6.

[f] A portion of CH_4 emitted from underground pipeline leaks is oxidized to form CO_2.

Table 7-64. Equipment-Level Fugitive Emission Factors for Distribution M&R Stations

Equipment Basis	**Reference Emission Factor [a], Original Units scf CH_4/station-hr**	**Uncertainty [b] (± %)**	**Emission Factor, Converted tonnes CH_4/station-yr [c]**	**Methane Content (mole %)**	**Emission Factor, Converted to Whole Gas scf gas/ station-yr [c]**
M&R >300 psig	179.8	46.9	30.2	93.4	1,686,347
M&R 100 - 300 psig	95.6	143	16.1		896,634
M&R <100 psig	4.31	334	0.72		40,424
Regulating >300 psig	161.9	70.9	27.2		1,518,463
R-Vault >300 psig	1.30	246	0.22		379,850
Regulating 100 - 300 psig	40.5	83.1	6.81		9,754
R-Vault 100 - 300 psig	0.180	116	0.0302		1,247
Regulating 40 - 100 psig	1.04	93.2	0.17		12,193
R-Vault 40 - 100 psig	0.0865	79.9	0.0145		1,688
Regulating <40 psig	0.133	172	0.0223		811

Footnotes and Sources:

[a] Campbell, L. M. and B. E. Stapper. *Methane Emissions from the Natural Gas Industry, Volume 10: Metering and Pressure Regulating Stations in Natural Gas Transmission and Distribution, Final Report*, GRI-94/0257.27 and EPA 600/R-96-080j. Gas Research Institute and U. S. Environmental Protection Agency, June 1996.

[b] Uncertainty is based on a 95% confidence interval based on the original data found in the source.

[c] Conversion assumes 8,760 hours of operation.

Table 7-65 also includes additional equipment-level emission factors for above-grade distribution M&R city gate stations, cited from GHGI (EPA GHGI, 2019). Note that some of these emission factors cite the same source as those in Table 7-63 above, but have been included here for completeness. These specific emission factor data references are noted in the footnotes below.

Table 7-65. Additional Fugitive Emission Factors for Above-Grade Distribution M&R City Gate Stations

Equipment Basis	**Reference Emission Factor [a], Original Units, kg CH_4/station-yr**	**Uncertainty (± %)**	**Emission Factor, Converted tonnes CH_4/station-yr**	**Methane Content (mole %)**	**Emission Factor, Converted to Whole Gas, scf gas/station-yr**
M&R >300 psig	2,142.70	Not specified	2.14	93.4	119,898
M&R 100 - 300 psig	995.4		1.00		55,699
M&R <100 psig [b]	727.2		0.73		40,691
Regulating >300 psig	868.9		0.87		48,621
R-Vault >300 psig	50.6		0.05		2,831
Regulating 100 - 300 psig	143.4		0.14	93.4	8,024
R-Vault 100 - 300 psig	50.6		0.05		2,831
Regulating 40 - 100 psig	163.7		0.16		9,160
R-Vault 40 - 100 psig	50.6		0.05		2,831
Regulating <40 psig [b]	22.4		0.02		1,253
Residential	1.5		1.50E-03		84
Commercial/Industry	9.7		0.01		543

Footnotes and Sources:

[a] EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 – 2017. 2019. These values were calculated using 2017 year-specific GHGRP Subpart W data by region.

Note: These factors, used in the USEPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017 (EPA 2019), are updated annually based on data reported from operators under the GHGRP.

[b] This factor is within 10% of the GRI 1996 factors from Table 7-62 and can be assumed to be the same factor.

Table 7-66 also provides fugitive equipment-level emission factors for below-grade natural gas distribution M&R stations, from USEPA's GHGRP. Note that these emission factors are specified as below grade emission factors (EPA, 2019).

Table 7-66. Fugitive Emission Factors for Below Grade M&R Stations

Equipment Basis	**Reference Emission Factor [a], Original Units, scf CH_4/station-hr**	**Uncertainty (± %)**	**Emission Factor, Converted tonnes CH_4/station-hr [b]**	**Methane Content (mole %)**	**Emission Factor, Converted to Whole Gas scf gas/station-yr [c]**
M&R >300 psig	1.3	Not specified	2.49E-05	93.4	12,193
M&R 100 - 300 psig	0.2		3.83E-06		1,876
M&R <100 psig	0.1		1.91E-06		938

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (USEPA), 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Table W-7. Data reported as of August 2, 2019. https://ecfr.io/Title-40/sp40.23.98.w.

[b] Conversion assumes 8,760 hours of operation.

Table 7-67 includes some additional, more detailed distribution segment equipment-level emission factors. The pipeline leak emission factors were derived from the GRI/EPA methane emissions project (Campbell, et al., Volume 9, 1996). The factor derivation is provided in Appendix C, Section C.3.6.

Table 7-67. More Detailed Equipment-Level Fugitive Emission Factors for Natural Gas Distribution Equipment

Source	Emission Factor [a, b], Original Units		Uncertainty [c] (± %)	Emission Factor, Converted to Tonnes		Gas Content (mole %)	Emission Factor, Converted to Whole Gas	
Cast iron pipeline, main length	10,096	lb CH_4/mile-yr	77.0	4.579	tonne CH_4/mile-yr	93.4 mole % CH_4	256,251	scf gas/mile-yr
				2.845	tonne CH_4/km-yr		159,227	scf gas/km-yr
CO_2 from oxidation [d]	18,699	lb CO_2/mile-yr	81.0	8.482	tonne CO_2/mile-yr	2 mole % CO_2	Not applicable	
				5.270	tonne CO_2/km-yr			
CO_2 from pipeline leaks	993.6	lb CO_2/mile-yr	81.1	0.4507	tonne CO_2/mile-yr		428,264	scf gas/mile-yr
				0.2800	tonne CO_2/km-yr		266,112	scf gas/km-yr
Plastic pipeline, main length	694.2	lb CH_4/mile-yr	260	0.3149	tonne CH_4/mile-yr	93.4 mole % CH_4	17,620	scf gas/mile-yr
				0.1956	tonne CH_4/km-yr		10,948	scf gas/km-yr
CO_2 from oxidation [d]	38.87	lb CO_2/mile-yr	261	0.01763	tonne CO_2/mile-yr	2 mole % CO_2	Not applicable	
				0.01096	tonne CO_2/km-yr			
CO_2 from pipeline leaks	41.62	lb CO_2/mile-yr	261	0.01888	tonne CO_2/mile-yr		17,939	scf gas/mile-yr
				0.01173	tonne CO_2/km-yr		11,147	scf gas/km-yr
Protected steel pipeline, main length	129.7	lb CH_4/mile-yr	128	0.05883	tonne CH_4/mile-yr	93.4 mole % CH_4	3,292	scf gas/mile-yr
				0.03655	tonne CH_4/km-yr		2,046	scf gas/km-yr
CO_2 from oxidation [d]	11.01	lb CO_2/mile-yr	130	0.004992	tonne CO_2/mile-yr	2 mole % CO_2	Not applicable	
				0.003102	tonne CO_2/km-yr			
CO_2 from pipeline leaks	7.856	lb CO_2/mile-yr	130	0.003563	tonne CO_2/mile-yr		3,386	scf gas/mile-yr
				0.002214	tonne CO_2/km-yr		2,104	scf gas/km-yr

Source	Emission Factor [a, b], Original Units		Uncertainty [c] (± %)	Emission Factor, Converted to Tonnes		Gas Content (mole %)	Emission Factor, Converted to Whole Gas	
Unprotected steel pipeline, main length	4,660	lb CH_4/mile-yr	133	2.114	tonne CH_4/mile-yr	93.4 mole % CH_4	118,277	scf gas/mile-yr
				1.313	tonne CH_4/km-yr		73,494	scf gas/km-yr
CO_2 from oxidation [d]	234.4	lb CO_2/mile-yr	135	0.1063	tonne CO_2/mile-yr	2 mole % CO_2	Not applicable	
				0.0661	tonne CO_2/km-yr			
CO_2 from pipeline leaks	278.8	lb CO_2/mile-yr	135	0.1265	tonne CO_2/mile-yr		120,169	scf gas/mile-yr
				0.0786	tonne CO_2/km-yr		74,670	scf gas/km-yr
Copper pipeline, services	10.76	lb CH_4/service-yr	172	0.004878	tonne CH_4/service-yr	93.4 mole % CH_4	273	scf gas/service-yr
CO_2 from oxidation [d]	0	lb CO_2/service-yr	N/A	0	tonne CO_2/service-yr	2 mole % CO_2	Not applicable	
CO_2 from pipeline leaks	0.6319	lb CO_2/service-yr	174	0.0002866	tonne CO_2/service-yr		272	scf gas/service-yr
Plastic pipeline, services	0.3932	lb CH_4/service-yr	234	0.0001784	tonne CH_4/service-yr	93.4 mole % CH_4	10	scf gas/service-yr
CO_2 from oxidation [d]	0.2903	lb CO_2/service-yr	235	0.0001317	tonne CO_2/service-yr	2 mole % CO_2	Not applicable	
CO_2 from pipeline leaks	0.02932	lb CO_2/service-yr	235	0.00001330	tonne CO_2/service-yr		13	scf gas/service-yr
Protected steel pipeline, services	7.464	lb CH_4/service-yr	178	0.003385	tonne CH_4/service-yr	93.4 mole % CH_4	189	scf gas/service-yr

Source	Emission Factor [a, b], Original Units		Uncertainty [c] (± %)	Emission Factor, Converted to Tonnes		Gas Content (mole %)	Emission Factor, Converted to Whole Gas	
CO_2 from oxidation [d]	0.5467	lb CO_2/service-yr	180	0.0002480	tonne CO_2/service-yr	2 mole % CO_2	Not applicable	
CO_2 from pipeline leaks	0.4502	lb CO_2/service-yr	180	0.0002042	tonne CO_2/service-yr		194	scf gas/service-yr
Unprotected steel pipeline, services	71.92	lb CH_4/service-yr	185	0.03262	tonne CH_4/service-yr	93.4 mole % CH_4	1,825	scf gas/service-yr
CO_2 from oxidation [d]	2.195	lb CO_2/service-yr	186	0.0009956	tonne CO_2/service-yr	2 mole % CO_2	Not applicable	
CO_2 from pipeline leaks	4.273	lb CO_2/service-yr	186	0.001938	tonne CO_2/service-yr		1,842	scf gas/service-yr

Footnotes and Sources:

[a] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, *Final Report*, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[b] The average CH_4 concentration associated with these emission factors provided in Table D-4 is 93.4 mole %; the average CO_2 concentration (for buried pipelines) also provided in Table D-4 is 2 mole %. If the actual concentration differs from the default value, the emission factors shown above can be adjusted by the ratio of the site concentration to the default concentration.

[c] Uncertainty based on 95% confidence interval from the data used to develop the original emission factor.

[d] A portion of CH_4 emitted from underground pipeline leaks is oxidized to form CO_2.

Table 7-68. Additional Equipment-Level Fugitive Emission Factors for Natural Gas Distribution Equipment

Source	Emission Factor [a, b], Original Units		Uncertainty (± %)	Emission Factor, Converted to Tonnes		Methane Content (Mole %)	Emission Factor, Converted to Whole Gas	
Distribution, Mains								
Cast Iron	1157.27	kg CH_4/mile-yr	Not specified	1.16	tonne CH_4/mile-yr	93.4	64,757	scf gas/mile-yr
				0.72	tonne CH_4/km-yr		40,238	scf gas/km-yr
Unprotected Steel	861.32	kg CH_4/mile-yr		0.86	tonne CH_4/mile-yr		48,197	scf gas/mile-yr
				0.54	tonne CH_4/km-yr		29,948	scf gas/km-yr
Protected Steel	96.75	kg CH_4/mile-yr		0.10	tonne CH_4/mile-yr		5,414	scf gas/mile-yr
				0.06	tonne CH_4/km-yr		3,364	scf gas/km-yr
Plastic	28.85	kg CH_4/mile-yr		0.03	tonne CH_4/mile-yr		1,614	scf gas/mile-yr
				0.02	tonne CH_4/km-yr		1,003	scf gas/km-yr
Distribution, Services								
Unprotected Steel	14.49	kg CH_4/mile-yr	Not specified	0.01	tonne CH_4/services-yr	93.4	811	scf gas/services-yr
Protected Steel	1.30	kg CH_4/mile-yr		1.30E-03	tonne CH_4/services-yr		72	scf gas/services-yr
Plastic	0.26	kg CH_4/mile-yr		2.63E-04	tonne CH_4/services-yr		15	scf gas/services-yr
Copper	4.90	kg CH_4/mile-yr		4.90E-03	tonne CH_4/services-yr		274	scf gas/services-yr

Footnotes and Sources:
[a] EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 – 2017. 2019. These values were calculated using 2017 year-specific GHGRP Subpart W data by region.
Note: These factors, used in the USEPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017 (EPA 2019), are updated annually based on data reported from operators under the GHGRP.
[b] The average CH_4 concentration associated with these emission factors provided in Table D-4 is 93.4 mole %; the average CO_2 concentration (for buried pipelines) also provided in Table D-4 is 2 mole %. If the actual concentration differs from the default value, the emission factors shown above can be adjusted by the ratio of the site concentration to the default concentration.

Early plastic pipes (pre-1982) were more susceptible to leakage than plastic pipes manufactured after 1982 that were built to the American Society of Testing and Materials (ASTM) D2837 standards. Factors such as brittle cracking may have contributed to the higher pipeline leaks from plastic pipelines manufactured prior to 1982. Using data from the 1996 GRI/EPA study (Campbell, et al., 1996) and data from Southern California Gas Company (SoCal, 1993), separate buried plastic pipeline fugitive leak emission factors were developed for pre-1982 plastic pipes and post-1982 (ASTM 2837) plastic pipelines.

Table 7-69 provides emission factors for plastic pipelines disaggregated on the basis of whether the pipes were manufactured before or after 1982 for the natural gas distribution sector. These emission factors are provided on both a leak basis and pipeline mileage basis. More detailed information on the derivation of these factors are provided in Appendix C, Section C.3.7.

Table 7-69. Fugitive Emission Factors from Distribution Underground Plastic Pipelines by Construction Year

Source [a]	Leak Based Emission Factors [b, c, d, e]				Pipeline Length Based Emission Factors [b, c, d, e]					
	Pre-1982		Post-1982 (ASTM D2837)		Pre-1982			Post-1982 (ASTM D2837)		
	(tonnes/leak-yr) [f]	Uncertainty (± %) [g]	(tonnes/leak-yr) [f]	Uncertainty (± %) [g]	(tonnes/mi-yr) [f, h]	(tonnes/km-yr) [f, h]	Uncertainty (± %) [g, i]	(tonnes/mi-yr) [f, h]	(tonnes/km-yr) [f, h]	Uncertainty (± %) [g, i]
CH_4 from pipeline leaks	0.983	164	0.166	36	0.162	0.100	324	0.027	0.017	159
CO_2 from pipeline leaks	0.059	157	0.010	26	0.010	0.006	313	0.0016	0.001	153
CO_2 from oxidation [j]	0.055	164	0.0093	36	0.009	0.006	324	0.0015	0.001	159

Footnotes and Sources:

[a] Distribution sector emission factors are based on a gas composition provided in Table D-4 of 93.4 mole % CH4 and 2.0 mole % CO2. Leak-based emission factors were converted to miles basis using 49,226 +/- 117.9% equivalent leaks from Table 8-6 and 299,421 +/-5% miles of distribution pipeline from Table 8-4 of Volume 9 of the 1996 GRI/EPA study.

[b] Emission factors derived from data presented in the 1996 GRI/EPA Study and from Southern California Gas Company (SoCal); refer to Appendix C, Section C.3.7, for more details.

[c] Campbell, L. M., M. V. Campbell, and D. L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, *Final Report*, GRI-94/0257.26 and EPA 600/R-96-080i. Gas Research Institute and U. S. Environmental Protection Agency, June 1996.

[d] Southern California Gas Company (SoCal). *A Study of the 1991 Unaccounted-for Gas Volume at the Southern Gas Company*, April 1993.

[e] The SoCal data were taken from: California Energy Commission (CEC). *Evaluation of Oil and Gas Sector Greenhouse Gas Emissions Estimation and Reporting, California Energy Commission, Consultant Report, Final Draft*, April 14, 2006.

[f] CH_4 emission factors converted from scf or m^3 are based on 60°F and 14.7 psia.

[g] Uncertainty based on 95% confidence interval from the data used to develop the original emission factor.

[h] Leak based emission factors were converted to miles basis based on the leak/miles ratio taken from data presented in Volume 9 of the 1996 GRI/EPA study. Equivalent leaks and pipeline miles were not provided by year of construction, so this conversion was based on the total US leaks and miles of pipeline. Factors were then converted to kilometer basis.

[i] Because the data used to calculate the activity factor for the referenced emission was unavailable, the Uncertainty at a 95% confidence interval was calculated from the reported 90% confidence interval assuming a data set size of ten.

[j] A portion of CH_4 emitted from underground pipeline leaks is oxidized to form CO_2. The conversion in the table above was based on 2.0% (+/- 25%) soil oxidation for plastic pipelines taken from Table 8-2 of Volume 9 of the GRI/EPA study.

7.3.4.3 Component Level – Average Emission Factor

The component-level average emission factor approach is based on the number of components in the facility. Where no monitoring data is available, this approach provides a more accurate estimation than equipment or facility level emission factors, since it is based on site-specific component population data. This methodology requires component counts; however, if this information is not available generic counts can be obtained as detailed in Appendix C, Section C.1.2.

Details on the methodologies and equations used to estimate TOC mass emissions for a given component type are included in Section 7.2.1.3. An example calculation illustrating the use of component-level fugitive emission factors is provided in Exhibit 7-2.

Table 7-49 in Section 7.3.2.3 provides natural gas transmission compressor station component-level emission factors for main line pressure (500 – 1000 psi) and fuel gas pressure (70 – 100 psi) as determined for components located on and off compressors (Howard, et al., 1999). These emission factors may be applicable to the distribution sector and can be used to determine fugitive emission factors for compressor stations in the distribution sector.

Table 7-70 provides average component-level emission factors for natural gas distribution meter/regulator stations.

Table 7-70. Natural Gas Distribution M&R Stations Average Component-Level Emission Factors

Component	Emission Factor [a], kg THC/hr/comp.	Emission Factor, tonne TOC/component-hr	Uncertainty [b, c] (± %)
Valves	0.00111	1.11E-06	162
Control valves	0.01969	1.97E-05	70.2
Connectors	0.00011	1.10E-07	92.1
Pressure relief valves	0.01665	1.67E-05	138
Open-ended lines (OEL)	0.08355	8.36E-05	53.0
OEL – station blowdown	0.9369	9.37E-04	61.6
Orifice meter	0.00333	3.33E-06	40.6
Other gas meter	0.00001	9.06E-09	116

Footnotes and Sources:

[a] Ross, B.D. and D.J. Picard, *Measurement of Methane Emissions from Western Canadian Natural Gas Facilities*, Gas Technology Canada, GTC Program #3, Environment Technology Program, September, 1996.

[b] Uncertainty based on 95% confidence interval from the data used to develop the original emission factor.

[c] Original emission factors were presented with upper and lower uncertainty limits. To be conservative, the larger % was chosen to represent the full % uncertainty of the mean value.

Average component-level emission factors for natural gas distribution commercial and residential sites are provided in Table 7-71.

Table 7-71. Natural Gas Distribution Commercial and Residential Sites Average Component-Level Emission Factors

Component	Emission Factor [a], kg THC/hr/comp.	Emission Factor, tonne TOC/component-hr	Uncertainty [b, c] (± %)
Valves	0.000003	3.33E-09	48.3
Connectors	0.000007	6.78E-09	131
Pressure relief valves	0.000272	2.72E-07	200
Open-ended lines (OEL)	0.083550	8.36E-05	53.0
Orifice meter	0.003333	3.33E-06	40.6
Other gas meter	0.000009	9.06E-09	116

Footnotes and Sources:

[a] Picard, D. J., B. D. Ross, and D. W. H. Koon. *A Detailed Inventory of CH_4 and VOC Emissions from Upstream Oil and Gas Operations in Alberta*, *Volume II*, Canadian Petroleum Association, March 1992.

[b] Uncertainty based on 95% confidence interval from the data used to develop the original emission factor.

[c] Original emission factors were presented with upper and lower uncertainty limits. To be conservative, the larger % was chosen to represent the full % uncertainty of the mean value.

Table 7-72 includes component-level emission factors for six regions across the United States, in which the study measured components for six types of industrial and commercial meter sets (rotary, turbine, diaphragm, orifice, ultrasonic, and regulating equipment). These regional average component-level emission factors are derived from a study by meter-related components including the cap, coupling, elbow, flange, meter, plug, pneumatic device, regulator, tee, valve, and other (strainer, filter, pilot, and compression fittings).

Table 7-72. Natural Gas Distribution Commercial and Industrial Meter Emission Average Component-Level Factors, by Region

Source	Original Emission Factor [a, b], kg CH_4/meter-hr	Uncertainty (± %)	Methane Emission Factor, tonne CH_4/ meter-hr	Methane Content (mole %)	Emission Factor, Converted to Whole gas, scf gas/meter-hr
Distribution, Commercial Meters					
All Regions	57.4	Not specified	0.06	93.4	3212
Midwest	28.4		0.03		1589
Northeast	20		0.02		1119
Pacific	4		4.00E-03		224
Rocky Mountains	108.4		0.11		6066
Southeast	139.3		0.14		7795
Southwest	153.9		0.15		8612
Distribution, Industrial Meters					
All Regions	117.8		0.12	93.4	6592
Midwest	52.3	Not specified	0.05		2927
Northeast	172.5		0.17		9652
Pacific	17.4		0.02		974
Rocky Mountains	322.5		0.32		18046
Southeast	291.7		0.29		16322
Southwest	372.9		0.37		20866

Footnotes and Sources:

[a] Gas Technology Institute. *Classification of Methane Emissions from Industrial Meters, Vintage vs Modern Plastic Pipe, and Plastic-lined Steel and Cast-Iron Pipe. Final Report*. U.S. Department of Energy. DOE Project Number DE-FE0029061. 30 June 2019.

[b] The breakdown of regions in the United States is as follows: Northeast – ME, VT, NH, MA, RI, CT, NY, NJ, PA, DE, MD. Southeast – WV, VA, KY, TN, NC, SC, GA, AL, MS, AR, LA, FL. Southwest – OK, TX, NM, AZ. Midwest – ND, SD, NE, KS, MN, IA, MO, WI, IL, MI, IN, OH. Rocky Mountain – MT, WY, CO, UT, ID, NV. Pacific – WA, OR, CA, AK, HI.

Table 7-73 includes California-specific component-level emission factors for natural gas distribution components by associated equipment, including piping segments and M&R stations.

Table 7-73. Additional Natural Gas Distribution Component-Level Emission Factors from California Study

Component	Emission Factor [a], tonnes CH_4/ component-yr	Uncertainty (± %)	Methane Content (mole %)	Converted Emission Factor, scf gas/component-yr
Piping Segments				
Manual Valves	1.47E-03	Not specified	93.4	82.26
Threaded Connection	2.16E-04			12.09

M&R Stations				
Flanges	5.93E-04	Not specified	93.4	33.18
Manual Valves	2.12E-04			11.86

Footnotes and Sources:

[a] Jeff Kuo, Travis C. Hicks, Brian Drake & Tat Fu Chan (2015) Estimation of methane emission from California natural gas industry, Journal of the Air & Waste Management Association, 65:7, 844-855, DOI: 10.1080/10962247.2015.102592

7.3.4.4 Component Level – Leaker Factors

OGI leaker factors are used to estimate emissions from facilities using OGI to evaluate for leaks. Using this approach, the facility only needs to know the number of leaks by component type. Using Equation 7-9, and converting to mass units using Equation 6-2, facilities can calculate the mass emission rate of CH_4 and CO_2 using the emission factors presented in the tables below.

Table 7-74 includes leaker component-level emission factors for transmission-distribution (T-D) transfer stations in gas service.

Table 7-74. Natural Gas T-D Transfer Station Component-Level Leaker Emission Factors

Component [a]	Emission Factor, Original Units [b], scf CH_4/ component-hr	Uncertainty (± %)	Emission Factor, tonne CH_4/ component-hr	Methane Content (mole % %)	Emission Factor, Converted to Whole gas, scf gas/ component-hr
Connector	1.69	Not specified	3.23E-05	93.4	1.81
Block Valve	0.557		1.07E-05		0.60
Control Valve	9.34		1.79E-04		10.00
Pressure Relief Valve	0.27		5.17E-06		0.29
Orifice Meter	0.212		4.06E-06		0.23
Regulator	0.772		1.48E-05		0.83
Open-ended Line	26.131		5.00E-04		27.98

Footnotes and Sources:

[a] T-D transfer station components exclude customer meters.

[b] U.S. Environmental Protection Agency (USEPA), 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Table W-7. Data reported as of August 2, 2019. https://ecfr.io/Title-40/sp40.23.98.w.

Table 7-75 includes fugitive leaker emission factors for six regions across the United States, in which the study measured components for six types of industrial and commercial meter sets (rotary, turbine, diaphragm, orifice, ultrasonic, and regulating equipment).

Table 7-75. Natural Gas Distribution Commercial and Industrial Meter Leaker Emission Factors, by Region

Source	Original Emission Factor [a, b], kg CH_4/meter-hr	Uncertainty (± %)	Methane Emission Factor, tonne CH_4/meter-hr	Methane Content (mole %)	Emission Factor, Converted to Whole gas. scf gas/ meter-hr
Distribution, Commercial Meters					
All Regions	132.4	Not specified	0.13	93.4	7409
Midwest	48.5		0.05		2714
Northeast	75.1		0.08		4202
Pacific	9		9.00E-03		504
Rocky Mountains	325.3	Not specified	0.33		18203
Southeast	174.1		0.17		9742
Southwest	399.1		0.40		22332
Distribution, Industrial Meters					
All Regions	277.4	Not specified	0.28	93.4	15522
Midwest	115.2		0.12		6446
Northeast	373.8		0.37		20917
Pacific	100.6		0.10		5629
Rocky Mountains	580.5		0.58		32483
Southeast	291.7		0.29		16322
Southwest	828.6		0.83		46365

Footnotes and Sources:

[a] Gas Technology Institute. *Classification of Methane Emissions from Industrial Meters, Vintage vs Modern Plastic Pipe, and Plastic-lined Steel and Cast-Iron Pipe. Final Report*. U.S. Department of Energy. DOE Project Number DE-FE0029061. 30 June 2019.

[b] The breakdown of regions in the United States is as follows: Northeast – ME, VT, NH, MA, RI, CT, NY, NJ, PA, DE, MD. Southeast – WV, VA, KY, TN, NC, SC, GA, AL, MS, AR, LA, FL. Southwest – OK, TX, NM, AZ. Midwest – ND, SD, NE, KS, MN, IA, MO, WI, IL, MI, IN, OH. Rocky Mountain – MT, WY, CO, UT, ID, NV. Pacific – WA, OR, CA, AK, HI.

7.3.4.5 Component Level –Screening Range Factor

This document does not cite any component-level screening range factors for natural gas distribution.

7.3.4.6 Correlation Equations Using Method 21 Monitoring

The correlation approach presented in previous segments of the gas value chain can be used for distribution, if Method 21 screening data is available. There are no distribution segment-specific correlation equations found as the Method 21 screening approach is less common in the distribution segment. The industry general emission factors and equations used for determining emissions using the correlation approach are presented in Section 7.3.1.6. An example calculation exhibiting the use of component-level screening factors is provided in Exhibit 7-5.

7.3.5 Crude Oil Transport

Appreciable methane emissions from equipment leaks are not anticipated from the crude oil transport sector. At this point in the oil lifecycle, the crude should be stabilized, meaning that any flashing may have already occurred upstream, either at the production pad or at gathering and boosting storage tanks. (Refer to Section 6.10 for Crude Oil Transport vented emissions and Section 6.4.5 for discussion of vented flashing losses associated with storage tanks in the gathering and boosting sector.) There were no published emission factors found for equipment leak emissions in the crude oil transport sector at the facility, equipment, or component level.

7.3.6 LNG Operations

LNG operations may include LNG terminals for import and export, LNG storage, LNG regasification, and LNG liquefaction plants.

7.3.6.1 Facility Level

Facility level emission factors for LNG storage and LNG import/export terminals are presented in Table 7-76. These default emission factors are derived for use in the US GHGI, based on a 4 year average of GHGRP Subpart W data (EPA, 2019b).

Table 7-76. Facility Level Emission Factors for LNG Storage and LNG Import/Export Terminals

Segment	Original Emission Factor [a], kg CH_4/ facility	Uncertainty (± %)	Emission Factor [e], tonne CH_4/ facility	Methane Content [e] (mole %)	Emission Factor, Converted to Whole gas, scf gas/facility
LNG Storage Stations	0.4394	Not specified	4.39E-04	95	24.15
LNG Import Terminals	0.3289		3.29E-04		18.08
LNG Export Terminals	1.2566		1.26E-03		69.07

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 – 2017*. 2019.

[b] CH_4 content used for conversion to whole gas is 95 mole % CH_4, the default mole fraction of CH_4 in natural gas stored in the LNG storage industry segment in 40 CFR 98 Subpart W.

7.3.6.2 Equipment Level

The following equipment-level emission factor was obtained from 40 CFR 98, Subpart W, “Mandatory Greenhouse Gas Reporting – Petroleum and Natural Gas Systems.” This factor is applicable to LNG Import and Export, specifically LNG terminals in gas service, as well as LNG storage, specifically LNG storage vapor recovery compressors in gas service.

4.17 scf CH_4/compressor-hr (Original Units) [a, b]
7.98E-05 tonne CH_4/compressor-hr (Converted)
4.39 scf whole gas/compressor-hr (Converted) [c]

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (USEPA), 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems, Table W-5B and Table W-6B. Data reported as of August 2, 2019. https://ecfr.io/Title-40/sp40.23.98.w.

[b] Uncertainty not specified.

[c] CH_4 content used for conversion to whole gas is 95 mole % CH_4, the default mole fraction of CH_4 in natural gas stored in the LNG storage industry segment in 40 CFR 98 Subpart W.

7.3.6.3 Component Level – Average Emission Factor

There were no published emission factors found regarding LNG operations at the population based component level.

7.3.6.4 Component Level –Leaker Factors

Leaker emission factors for LNG storage and LNG Import/Export are presented in Table 7-77 were obtained from 40 CFR 98, Subpart W, "Mandatory Greenhouse Gas Reporting – Petroleum and Natural Gas Systems." These factors can be used if surveys have been completed based on GHGRP Subpart W 40 CFR §98.234(a)(1)-(6), including leak screening using OGI cameras and Method 21 surveys conducted at a leak threshold of 10,000 ppmv.

Table 7-77. Default Methane Leaker Emission Factors for LNG Storage and LNG Import/Export Terminals: Surveys using OGI and Method 21 Screening at 10,000 ppmv Leak Threshold

Component	**Original Emission Factor [a], scf gas/ component-hr**	**Uncertainty (± %)**	**Emission Factor [e], tonne CH_4/ component-hr**	**Methane Content [e] (mole %)**	**Emission Factor, Converted to Whole gas, scf gas/component-hr**
Service – LNG Service					
Valve	1.19	Not specified	2.28E-05	95	1.25
Pump Seal	4		7.65E-05		4.21
Connector	0.34		6.51E-06		0.358
Other [b]	1.77		3.39E-05		1.86
Service – Gas Service					
Valve [c]	14.84	Not specified	2.84E-04	95	15.6
Connector	5.59		1.07E-04		5.88
Open-ended Line	17.27		3.30E-04		18.2
Pressure relief valve	39.66		7.59E-04		41.8
Meter and Instrument	19.33		3.70E-04		20.4
Other [d]	4.1		7.84E-05		4.3

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (USEPA), 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Table W-5A and Table W-6A. Data reported as of August 2, 2019. https://ecfr.io/Title-40/sp40.23.98.w.

[b] Other equipment type for components in LNG service should be applied for any equipment type other than connectors, pumps, or valves.

[c] Valves includes control valves, block valves, and regulator valves.

[d] Other equipment type for components in gas service should be applied for any equipment type other than valves, connectors, flanges, open-ended lines, pressure relief valves, and meters and instruments, as specified in §98.232(g)(6) and (7).
[e] CH_4 content used for conversion to whole gas is 95 mole % CH_4, the default mole fraction of CH_4 in natural gas stored in the LNG storage industry segment in 40 CFR 98 Subpart W.

Table 7-78 contains leaker emission factors that can be used if surveys have been completed based on Method 21 with a leak detection threshold of 500 ppmv[10] , for LNG storage and LNG Import/Export (EPA GHGRP, 2019).

Table 7-78. Default Methane Leaker Emission Factors for LNG Storage and LNG Import/Export Terminals: Method 21 Surveys at 500 ppm Leak Detection Threshold

Component	**Original Emission Factor [a], scf CH_4/ compressor-hr**	**Uncertainty (± %)**	**Methane Emission Factor, tonne CH_4/ compressor-hr**	**Methane Content [e] (mole %)**	**Emission Factor, Converted to Whole gas, scf gas/ component-hr**
Service – LNG Service					
Valve	0.23	Not specified	4.40E-06	Not specified	0.242
Pump Seal	0.73		1.40E-05		0.768
Connector	0.11		2.10E-06		0.116
Other [b]	0.99		1.89E-05		1.042
Service – Gas Service					
Valve [c]	9.51	Not specified	1.82E-04	Not specified	10.01
Connector	3.58		6.85E-05		3.77
Open-ended Line	11.07		2.12E-04		11.65
Pressure relief valve	25.42		4.86E-04		26.76
Meter and Instrument	12.39		2.37E-04		13.04
Other [d]	2.63		5.03E-05		2.77

Footnotes and Sources:
[a] U.S. Environmental Protection Agency (USEPA), 2019. Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Table W-5A and Table W-6A. Data reported as of August 2, 2019. https://ecfr.io/Title-40/sp40.23.98.w.
[b] Other equipment type for components in LNG service should be applied for any equipment type other than connectors, pumps, or valves.
[c] Valves includes control valves, block valves, and regulator valves.
[d] Other equipment type for components in gas service should be applied for any equipment type other than valves, connectors, flanges, open-ended lines, pressure relief valves, and meters and instruments, as specified in §98.232(g)(6) and (7).
[e] CH_4 content used for conversion to whole gas is 95 mole % CH_4, the default mole fraction of CH_4 in natural gas stored in the LNG storage industry segment in 40 CFR 98 Subpart W.

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[10] as specified in 40 CFR §98.234(a)(7) of the GHGRP

7.3.6.5 Component Level –Screening Range Factors

This document does not cite any component-level screening range factors (i.e., leak / no-leak factors) for LNG operations.

7.3.6.6 Correlation Equations Using Method 21 Monitoring

The correlation approach presented in previous segments of the gas value chain can be used for LNG liquefaction and transport, if Method 21 screening data is available. There were no LNG-specific correlation equations found in the literature.

The industry general emission factors and equations used for determining emissions using the correlation approach are presented in Section 7.3.1.6. An example calculation exhibiting the use of component-level screening factors is provided in Exhibit 7-5.

7.4 Equipment Leaks Estimation – Downstream Operations

7.4.1 Refining

Greenhouse gas emissions from refining occur primarily from combustion of fuels to provide the energy needed for the refining processes and a number of specialized process vents that also contribute GHG emissions. Emissions from combustion are discussed in Section 4.0. Emissions from process vents are discussed in Section 6.11. Refinery CH_4 emissions from equipment leaks represent a very small fraction of the total GHG emissions based on the data prepared by API (see Appendix E.)

Methane emissions from equipment leaks may result from the piping and components associated with the natural gas supply system, as well as the refinery fuel gas system, which are the only process streams within the refinery with potentially significant CH_4 concentrations.

Leaks from equipment used in association with “weathered” crude or refined oil and gas products will not emit significant CH_4 or CO_2, because “weathered” crude and refined oil and gas products do not contain appreciable CH_4 or CO_2.[11]

A summary of all the emission factor sets included for midstream oil and gas operations is provided in Table 7-79. As shown, the emission factor sets are organized by the type of operation and the equipment leak approach. This summary is intended to help guide the user in selection of the most appropriate emission factors for quantification of equipment leak emissions from

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[11] For more information, see Appendix E.

midstream operations. The application of specific sets of emission factors will depend on the type of operation and the data available for quantifying equipment leak emissions.

7.4.1.1 Facility Level

Average facility-level emission factors can be applied when data on component counts and leak screening are not available. For refineries, the facility-level approach should provide a reasonable estimate of the fugitive emissions from the facility equipment, as these sources are not expected to be material to the overall inventory. Exhibit 7-1 presents an example of calculating CH_4 emissions using the facility-level emission factor approach.

The following average facility emission factor from GHGI can be used to estimate equipment leaks from refineries at the facility-level, based on refinery feed rate. The emission factor below is from the U.S. Greenhouse Gas Emissions and Sinks for estimating equipment leaks from refineries, using data from 2017 (EPA, 2019b).

0.43 kg $CH_4/10^3$ bbl refinery feed (Original Units) [a, b]

4.34E-04 tonne $CH_4/10^3$ bbl refinery feed (Converted)

Footnotes and Sources:

[a] EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 – 2017. 2019. These values were calculated using 2017 year-specific GHGRP Subpart Y data. Note: These factors, used in the USEPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017 (EPA 2019), are updated annually based on data reported from operators under the GHGRP.

[b] Uncertainty for the original value is not specified.

Table 7-79. Equipment Leaks Emission Factor Summary Table – Downstream Operations

Table Number	Table Title	Data Source(s)	Location	Year Published	Measurement Approach	Sample Size	Original Data Source
Section 7.4.1.1 Refining – Facility Level							
Unnumbered and Unnamed table in 7.4.1.1		EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 – 2017. 2019.	US	2019	These values were calculated using 2017 year-specific GHGRP Subpart W data by region.		
7-80	Facility-Level Average Fugitive Emission Factors for Refinery Gas Systems	American Petroleum Institute (API). Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry. Appendix F. August 2009.	US	2009	Direct measurement study (method unspecified)	Inventory GHG and component count data from two refineries	Data provided by two refineries for use in deriving emission factors

In addition to the overall facility-level emission factor for a refinery provided above, emission factors for the gas systems within a refinery are also available. The facility-level emission factors provided in Table 7-80 may be used to estimate CH_4 fugitive emissions from refining fuel gas and natural gas systems. The factors in Table 7-80 were derived from an API study conducted to assess the contribution of fugitive CH_4 emissions from equipment leaks to overall refinery GHG emissions. Emissions were estimated based on component counts in natural gas and refinery fuel gas service, using average emission factors for components in gas service provided by EPA (EPA, 1995). Fugitive CH_4 emissions were calculated for two refineries:

- A smaller fuels refinery with a rated capacity between 50,000 and 90,000 bbl feed/day; and
- A larger refinery/petrochemical complex with a rated capacity between 100,000 and 199,000 bbl feed/day.

Results indicated that CH_4 emissions from equipment leaks represent 0.11% of total GHG emissions for the smaller refinery and 0.19% of total emissions for the large refinery. Since other large GHG emitting sources have uncertainties within the range of 1% to 5% of the overall GHG inventory, a CH_4 fugitive emission contribution of 0.1% appears to be negligible. A summary report on the study is provided in Appendix E.

The simple, refinery gas system equipment-level fugitive emission factors for the fuel gas and natural gas systems were estimated by dividing the CH_4 emission rates from the study by the refinery feed rate capacities. The mid-point of the range of the capacities was used when deriving the emission factors. Since these emission factors were derived from very limited data, they should be used with caution because the fugitive emissions are likely to be highly variable depending on the refinery. However, as noted earlier, refinery CH_4 fugitive emissions represent a very small fraction of the total GHG emissions based on the data provided in Appendix E.

In addition to CH_4, CO_2 also may be released from fugitive sources if CO_2 is present in the gas stream (e.g., carbon capture systems). Fugitive emission factors specific to CO_2 are limited in current, publicly available studies. As an approximation, the CH_4 emission factor can be adjusted to account for the CO_2 composition of the gas for fugitive sources as demonstrated in Section 7.2.1.1 and Exhibit 7-1. Fugitive emissions from leaks associated with pipeline transport of CO_2 are discussed in below in Section 7.3.3.

Table 7-80. Facility-Level Average Fugitive Emission Factors for Refinery Gas Systems

Source	Emission Factor Original Units		Uncertainty (± %)	Emission Factor [a] Converted Units
Fuel gas system – 50,000 to 99,000 bbl/day refinery [b, c, d, e]	10.2	tonnes CH_4/yr	Not available	3.75E-04 tonnes $CH_4/10^3$ bbl feedstock
				2.36E-03 tonnes $CH_4/10^3$ m^3 feedstock
Fuel gas system – 100,000 to 199,000 bbl/day refinery [b, c, d]	77	tonnes CH_4/yr		1.41E-03 tonnes $CH_4/10^3$ bbl feedstock
				8.88E-03 tonnes $CH_4/10^3$ m^3 feedstock
Natural gas system – 50,000 to 99,000 bbl/day refinery [b, c, d]	26	tonnes CH_4/yr		9.56E-04 tonnes $CH_4/10^3$ bbl feedstock
				6.01E-03 tonnes $CH_4/10^3$ m^3 feedstock
Natural gas system – 100,000 to 199,000 bbl/day refinery [b, c, d]	55	tonnes CH_4/yr		1.01E-03 tonnes $CH_4/10^3$ bbl feedstock
				6.34E-03 tonnes $CH_4/10^3$ m^3 feedstock

Footnotes and Sources:

[a] The emission factors can be adjusted based on the relative concentrations of CH_4 and CO_2 to estimate CO_2 emissions.

[b] Emission factors were derived from data from an API refinery CH_4 fugitive emissions study provided in Appendix E. The estimated refinery fugitive CH_4 emission rates from the study for the fuel gas and natural gas systems were divided by the refinery feed capacity for the two refineries in the study, a 50,000 to 99,000 bbl/day "single train (multiply HDS)" refinery and a 100,000 to 199,000 bbl/day "old multi-train refinery." The mid-point of the range of the refinery capacities was assumed when deriving the emission factors (i.e., the estimated CH4 fugitive emission rates were divided by 74,500 bbl feed/day for the smaller refinery and by 149,500 bbl feed/day for the larger refinery). Refer to Appendix E for the data used to estimate the emission factors.

[c] Mid range capacity was assumed to convert emissions to a throughput basis.

[d] Uncertainty is based on a 95% confidence interval from the data used to develop the original emission factor.

[e] Emission factor refers to fuel gas + make gas.

7.4.1.2 Equipment Level

Equipment level emissions can be estimated by the count of major equipment at a refinery using Equation 7-16, based on the method presented in 40 CFR § 98.253 of US EPA's GHGRP Subpart Y (EPA, 2019a).

$$E_{CH_4} = 0.4 \times N_{CD} + 0.2 \times N_{PU1} + 0.1 \times N_{PU2+4.3} \times N_{H2} + 6 \times N_{FGS} \quad \text{Equation 7-16}$$

where

E_{CH4} = Annual methane emissions from refinery equipment leaks, metric tonnes/year.
N_{CD} = Number of atmospheric crude oil distillation columns at the facility.
N_{PU1} = Cumulative number of catalytic cracking units, coking units (delayed or fluid), hydrocracking, and full-range distillation columns (including depropanizer and debutanizer distillation columns) at the facility.
N_{PU2} = Cumulative number of hydrotreating/hydrorefining units, catalytic reforming units, and visbreaking units at the facility.
N_{H2} = Total number of hydrogen plants at the facility.
N_{FGS} = Total number of fuel gas systems at the facility.

7.4.2 Petroleum Products Transport and Marketing

Evaporative emissions of liquid hydrocarbons may occur during liquid fuel transfer or pumping activities, but the concentration of CH_4 or other GHGs is negligible in the refined products as shown by the compositions presented in Appendix D. Therefore, there generally are no significant GHG emissions from these activities.

Methane emissions may result from process equipment leaks associated with LNG or compressed natural gas (CNG) marketing. These emissions can be calculated using the techniques and factors presented in Section 7.3.2 for Natural Gas Transmission and Storage, 7.3.3 for Natural Gas Distribution, and 7.3.5 for the LNG Supply Chain.

7.5 Other Fugitive Emissions

7.5.1 Wastewater Treatment

Wastewater treatment can be a source of CH_4 when treated or disposed of anaerobically. Under aerobic conditions, it can be a source of N_2O and CO_2 emissions that are byproducts of the digestion of larger organic molecules. However, CO_2 emissions from wastewater are generally disregarded because most are of biogenic origin (IPCC, 2019).

Figure 7-3 provides a decision tree for different methodologies available to estimate emissions from wastewater treatment. These approaches are based on the volume of wastewater processed, Biochemical or Biological Oxygen Demand (BOD) or Chemical Oxygen Demand (COD) data, contribution significance of resulting emissions to overall emissions, and availability of data to run the WATER9, Version 3.0 program.[12] Anaerobic and aerobic treatments are discussed separately in the following subsections.

In some cases, vapors from wastewater treatment may be controlled through a combustion device or may be captured and routed to a gas disposal well. Emissions from wastewater vents routed to a combustion control device should be estimated using the techniques presented in Section 5. Alternatively, if vapors are captured, a capture efficiency should be applied to the emission estimation approaches presented in this subsection.

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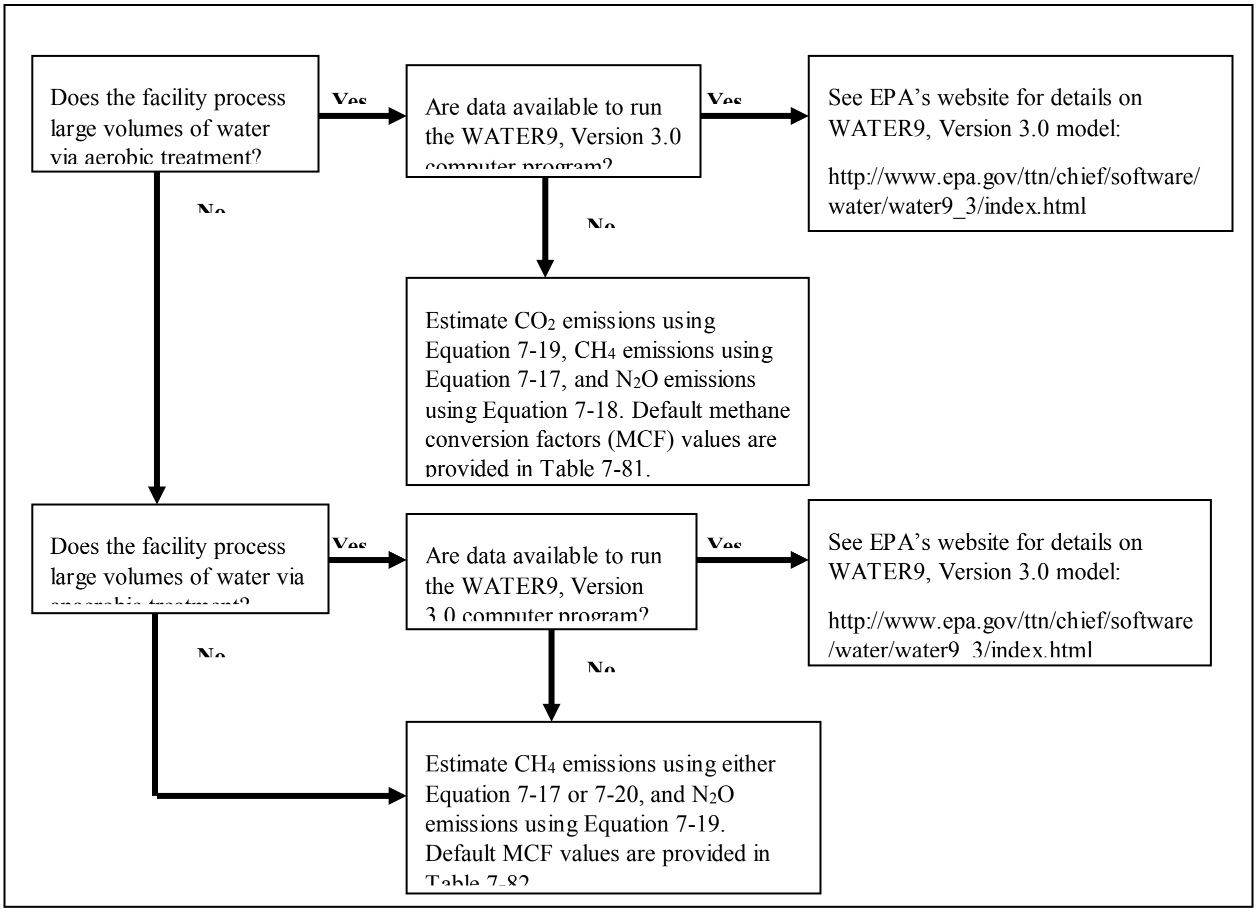
[12] http://www.epa.gov/ttn/chief/software/water/water9_3/index.html.



Does the facility process large volumes of water via aerobic treatment?

Are data available to run the WATER9, Version 3.0 computer program?

See EPA's website for details on WATER9, Version 3.0 model:

http://www.epa.gov/ttn/chief/software/water/water9_3/index.html

Estimate CO_2 emissions using Equation 7-19, CH_4 emissions using Equation 7-17, and N_2O emissions using Equation 7-18. Default methane conversion factors (MCF) values are provided in Table 7-81.

Does the facility process large volumes of water via anaerobic treatment?

Are data available to run the WATER9, Version 3.0 computer program?

See EPA's website for details on WATER9, Version 3.0 model:

http://www.epa.gov/ttn/chief/software/water/water9_3/index.html

Estimate CH_4 emissions using either Equation 7-17 or 7-20, and N_2O emissions using Equation 7-19. Default MCF values are provided in Table 7-82.

Figure 7-3. Wastewater Treatment

A general method for estimating TOC evaporative emissions from wastewater treating, impoundments, and pits is available in the EPA computer program WATER9, Version 3.0, which allows for estimating air emissions of individual waste constituents in wastewater collection, storage, treatment, and disposal facilities. Although CH_4 and CO_2 evaporative emissions from oil and gas wastewater are expected to be insignificant, facilities with unique situations can find more information on WATER9, Version 3.0 at:

http://www3.epa.gov/ttn/chief/software/water/water9_3/index.html

IPCC provides a detailed method for estimating emissions from wastewater treatment (IPCC, 2006). This approach can be applied to aerobic or anaerobic wastewater treatment. Methane emissions from industrial wastewater are calculated using Equation 7-17.[13]

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[13] Equation 7-17 combines Equations 6-4, 6-5, and 6-6 in *2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 5, Chapter 6: Wastewater Treatment and Discharge* (IPCC, 2006), with no updates in the 2019

$$E_{CH_4} = [(P \times W \times COD)\text{-}S] \times B \times MCF \times 0.001 \qquad \text{(Equation 7-17)}$$

where

E_{CH_4} = emission rate of CH_4 (tonnes/yr);

P = product generated (ton product/yr);

W = wastewater generation rate (m^3/ton product);

COD = average chemical oxygen demand of the wastewater (kg/m^3);

S = organic component removed as sludge (kg COD/yr);

B = methane generation capacity (B = 0.25 kg CH_4/kg COD);

MCF = methane conversion factor (Table 7-81 for aerobic treatment, Table 7-82 for anaerobic treatment); and

0.001 = conversion factor (kg to metric tonnes).

Note that if the volume of wastewater treated is known, the term P × W in Equation 7-17 can be replaced directly with the volume treated (m^3/yr).

IPCC provides the following COD default factors and ranges for maximum CH_4 producing capacity for oil and gas refineries and the organic chemical industry (IPCC, 2019):

1. For oil and gas refineries, a typical COD production rate of 1 kg COD per m^3 of wastewater generation, with the COD value ranging between 0.4 and 1.6 kg COD/m^3.
2. For the organic chemical industry, a typical COD production rate of 3 kg COD per m^3 of wastewater generation, with the COD value ranging between 0.8 and 5 kg COD/m^3.

IPCC also provides default factors and ranges for wastewater generation rates associated with the oil and gas refineries and the organic chemical industry (IPCC, 2019):

1. For oil and gas refineries, the typical wastewater generation rate is 0.6 m^3/ton product, with the generation rate ranging between 0.3 and 1.2 m^3/ton product.
2. For the organic chemical industry, the typical wastewater generation rate is 67 m^3/ton product, with a range between 0 and 400 m^3/ton product.

Default MCF values are provided in Table 7-81 for aerobic treatment and Table 7-82 for anaerobic treatment. Also shown in the following tables are default methane emission factors that can be used if the data needed for Equation 7-17 is not available.

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refinement.

Table 7-81. Default MCF Values for Aerobic Industrial Wastewater Treatment

Type of Treatment [a]	Default MCF (MCF Range)	Methane Emission Factor (kg CH_4/kg BOD)	Methane Emission Factor (kg CH_4/kg COD)
Centralized, Aerobic treatment plant [b]	0 (0 – 0.1)	0	0

Footnotes and Sources:

[a] IPCC, *2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 5, Chapter 6: Wastewater Treatment and Discharge*, 2019.

[b] Some CH_4 can be emitted from settling basins and other anaerobic pockets. For treatment plants that are receiving wastewater beyond design capacity, inventory compilers should judge the amount of organic material removed in sludge accordingly (IPCC, 2019).

Table 7-82. Default MCF Values for Anaerobic Industrial Wastewater Treatment

Type of Treatment [a]	Default MCF (MCF Range)	Methane Emission Factor (kg CH_4/kg BOD)	Methane Emission Factor (kg CH_4/kg COD)
Anaerobic reactor [b, c]	0.8 (0.8 – 1.0)	0.48	0.2
Anaerobic digestion at biogas facilities	N/A	0.002 (0 – 0.02) kg CH_4/kg dry waste [d, e]	
Anaerobic shallow lagoon and facultative lagoons [f]	0.2 (0 – 0.3)	0.12	0.05
Anaerobic deep lagoon [g]	0.8 (0.8 – 1.0)	0.48	0.2

Footnotes and Sources:

[a] IPCC, *2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 5, Chapter 6: Wastewater Treatment and Discharge*, 2019.

[b] Examples include upflow anaerobic sludge blanket digestion (UASB) (IPCC, 2019).

[c] CH_4 recovery is not considered here (IPCC, 2019).

[d] Emission factor from IPCC, *2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 5, Chapter 4: Biological Treatment of Solid Waste*, 2006, Table 4.1. Provided in the table is the larger emission factor, on a dry weight basis, in terms of kg CH_4/kg waste treated.

[e] This emission factor is on a dry weight basis. On a wet weight basis, the emission factor is 0.0008 kg CH_4/kg waste treated with a range of 0 to 0.008 kg CH_4/kg waste treated.

[f] Depth less than 2 meters, use expert judgement (IPCC, 2019).

[g] Depth more than 2 meters (IPCC, 2019).

For either aerobic or anaerobic wastewater, N_2O emissions are calculated using Equation 7-18. Note that the default emission factor for N_2O (0.005 kg N_2O-N/kg N) is a factor for domestic wastewater nitrogen effluent (IPCC, 2006), but is assumed to be applicable for wastewater applications at oil and gas facilities.

$$E_{N_2O} = Q \times N \times EF_{N_2O} \times \frac{44}{28} \times 0.001 \qquad \text{(Equation 7-18)}$$

where

E_{N_2O} = emission rate of N_2O (tonnes/yr);

Q = volume of wastewater treated (m^3/yr);

N = average concentration of N in effluent (kg N/m^3);

EF_{N_2O} = emission factor for N_2O from discharged wastewater (0.005 kg N_2O-N/kg N);

44/28 = conversion factor (kg N_2O-N to kg N_2O); and

0.001 = conversion factor (kg to metric tonnes).

7.5.1.1 Aerobic Wastewater Treatment

Aerobic wastewater treatment is more common in oil and gas industry operations than anaerobic treatment. In aerobic conditions, bacteria consume organic material and convert it to CO_2. According to IPCC, the generation of CO_2 from aerobic wastewater treatment is not included as part of a GHG inventory because the carbon is viewed as part of the biogenic cycle (IPCC, 2006). However, in oil and gas operations, oil and gas-based organic material in the wastewater would not be considered biogenic, just as the oil and gas organic material that is combusted or released through vented and fugitive sources is not biogenic.

Carbon dioxide emissions from aerobic wastewater are produced through two mechanisms: the oxidation of organic material to produce new bacterial cells, and endogenous respiration. The oxidation of carbonaceous organic material is represented by measuring the biochemical oxidation (BOD). Assuming that the ultimate BOD removed is represented by $BOD_5/0.7$,[14] the following equation can be used to estimate CO_2 emissions from aerobic wastewater treatment:

$$E_{CO_2} = \text{WW Flow} \times \frac{3.785412\ \text{L}}{\text{gal}} \times \frac{BOD_5}{0.7} \times \frac{44}{32} \times \frac{\text{tonne}}{10^9\ \text{mg}} \qquad \text{(Equation 7-19)}$$

where

E_{CO_2} = emission rate of CO_2 (tonnes/yr);

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[14] The factor "BOD5/0.7" represents an estimate of the total or ultimate BOD, L (i.e., the total or ultimate first-stage BOD initially present). The BOD5 and ultimate BOD (L) are related by the following equation: BOD5 = L (1 - e^-kt), where k is the reaction rate constant and t is time of the BOD remaining in the water (Metcalf and Eddy, 1991). For wastewater, a typical value of 0.23 day^-1 at 68°F is provided by a common wastewater engineering handbook (Metcalf and Eddy, 1991). Therefore, the equation for the ultimate BOD with the values substituted is L = BOD5/[1-e^- (0.23)(5)] = BOD5/0.7.

WW Flow = wastewater flow rate (10^6 gallons/yr);

$BOD_5/0.7$ = approximation of the ultimate BOD (mg/L); and

44/32 = oxygen to CO_2 conversion factor.

Methane and N_2O emissions from aerobic wastewater treatment are calculated using Equations 7-17 and 7-18, respectively (IPCC, 2006). For CH_4 however, aerobic conversion factors are provided in Table 7-82.

EXHIBIT 7-6: Sample Calculation for Aerobic Treatment Approach

INPUT DATA:

An aerobic wastewater treatment system processes 5 million gallons per day with a BOD removal of 120 mg/L (BOD_5). Estimate the CO_2 emissions.

CALCULATION METHODOLOGY:

1. *Calculate CO_2 emissions using Equation 7-19.*

$$E_{CO_2} = \text{WW Flow} \times \frac{3.785412\text{ L}}{\text{gal}} \times \frac{BOD_5}{0.7} \times \frac{44}{32} \times \frac{\text{tonne}}{10^9\text{ mg}}$$

$$= \frac{5\times10^6\text{ gal}}{\text{day}} \times \frac{365\text{ days}}{\text{yr}} \times \frac{3.785412\text{ L}}{\text{gal}} \times \frac{120\text{ mg/L}}{0.7} \times \frac{44}{32} \times \frac{\text{tonne}}{10^9\text{ mg}}$$

$$= \underline{1,628\text{ tonnes CO}_2\text{ / yr}}$$

7.5.1.2 Anaerobic Wastewater Treatment

Anaerobic water treatment is not common in the oil and gas industry, and it is possible to recover the CH_4 generated for use as a fuel. For these reasons, anaerobic water treating is not considered a significant GHG emission source for the oil and gas industry.

Methane and N_2O emissions from anaerobic wastewater treatment can be calculated using Equations 7-17 and 7-18, respectively. Table 7-82 provides default CH_4 conversion factors for anaerobic wastewater treatment for use with Equation 7-17.

Alternatively, EPA presents a relatively simple method for estimating CH_4 emissions for facilities where CH_4 is not captured from an anaerobic water treatment system (EPA AP-42 Section 4.3.5.2, 1998). The following equation applies:

$$E_{CH_4} = Q \times \left(\frac{\text{lb BOD}_5}{\text{ft}^3 \text{wastewater}} \right) \times \left(\frac{0.22 \text{ lb CH}_4}{\text{lb BOD}_5} \right) \times F_{AD} \times 365 \qquad \text{(Equation 7-20)}$$

where

E_{CH_4} = emission rate of CH_4 in pounds per year;

Q = wastewater flow rate in cubic feet per day;

BOD_5 = biochemical oxygen demand measured using the standard five day test;

F_{AD} = fraction anaerobically digested; and

365 = days per year.

A site-specific value for BOD_5 loading should be available from facility wastewater treating staff. If it is not, EPA suggests a default value of 0.25 pounds BOD_5 per cubic foot of wastewater for the oil and gas industry. The fraction anaerobically digested is that part of the wastewater flow that is routed to anaerobic treatment rather than aerobic treatment.

The emission rate for CO_2 from anaerobic water treatment is considered to be negligible compared to the CH_4 emission rate. No equation or emission factors have been found to estimate these emissions.

An example calculation for CH_4 emissions from anaerobic water treatment follows in Exhibit 7-7.

EXHIBIT 7-7: Sample Calculation for Anaerobic Treatment Approach

INPUT DATA:

A wastewater treatment system processes 870,000 cubic feet per day, with 10% of the water going to anaerobic treatment (anaerobic shallow lagoon). The BOD_5 level of the influent averages 0.3 pounds per cubic foot. Calculate the CH_4 emissions using Equation 7-20 and the IPCC approach.

CALCULATION METHODOLOGY:

1. *Calculate CH_4 emissions using Equation 7-20.* Using Equation 7-20, the estimated emissions are:

$$E_{CH_4} = 870{,}000\frac{ft^3}{day}\times\left(\frac{0.1\ ft^3\ \text{anaerobic}}{ft^3\text{processed}}\right)\times\left(\frac{0.3\ lb\ BOD_5}{ft^3\text{wastewater}}\right)\times\left(\frac{0.22\ lb\ CH_4}{lb\ BOD_5}\right)$$
$$\times 365\ \frac{days}{year}\times\frac{tonne}{2204.62\ lb}$$

$$\underline{E_{CH_4} = 950.7\ \text{tonne}\ CH_4/yr}$$

2. *Calculate CH_4 emissions using IPCC's approach.* Using IPCC's approach (Equation 7-17), assuming the default COD rate for a refinery (1 kg COD per m^3 of wastewater) and the default MCF from Table 7-82 (0.2), the estimated emissions are calculated as follows:

$$E_{CH_4} = 870{,}000\frac{ft^3}{day}\times\left(\frac{0.1\ ft^3\ \text{anaerobic}}{ft^3\text{processed}}\right)\times 365\frac{days}{year}\times\frac{m^3}{35.3147\ ft^3}\times\frac{1\ kg\ COD}{m^3}\times\frac{0.25\ kg\ CH_4}{kg\ COD}$$
$$\times 0.2\times\frac{0.001\ \text{tonne}\ CH_4}{kg\ CH_4}$$

$$\underline{E_{CH_4} = 44.96\ \text{tonne}\ CH_4/yr}$$

7.5.2 Biotreaters

There are applications in the oil and gas industry where biotreaters (or biofilters) are used in treating wastewater and/or as control devices to remove TOC from vent streams. The CO_2 emissions from biotreaters are expected to be insignificant compared to major sources like combustion. The CO_2 production from biotreaters can be estimated from the feed TOC rate and the biomass conversion efficiency. The produced CO_2 is partially emitted to the air and partially converted to carbonates depending on system pH. In the unusual cases where biotreater emissions may be significant, it would be best to develop the emissions estimates based on the site-specific features of the biotreater and its feed streams.

7.6 Fluorinated Gas Emissions

In addition to fugitive emission sources of CH_4 or CO_2, there may be equipment or operations associated with oil and gas industry activities that result in emissions of CFCs, HCFCs, HFCs, PFCs, and SF_6. Chlorofluorocarbons and HCFCs are regulated under the Montreal Protocol, and are not typically included in a GHG inventory. However, HFCs, PFCs, and SF_6 are accounted for under most GHG registry programs. Potential fugitive emission sources of HFC emissions for the oil and gas industry are leakage from the operation of chillers and air conditioning equipment, including air conditioning for mobile sources. Emissions of SF_6 may result from electrical transmission and distribution equipment, and from the use of SF_6 as a tracer gas to detect leaks.

Emissions of fluorinated substances and SF_6 can be calculated using either a mass balance approach or default operating emission factors. When using the mass balance approach, emissions are commonly reported during the year of recharge, even though fugitive emissions of these substances can occur over multiple years.

7.6.1 Air Conditioning and Refrigeration Equipment

Emissions from refrigeration and air conditioning equipment are expected to be very small for oil and gas industry operations. This section discusses emissions from the operation of air conditioning and refrigeration equipment. Although emissions can also occur from the manufacture and disposal of fluorinated substances, these activities are generally not conducted as part of oil and gas operations.[15] Figure 7-4 provides a decision tree for estimating refrigerant emissions based on the contribution of these emissions to the entity’s inventory.

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[15] An additional calculation methodology for the manufacture, installation, or disposal of refrigeration and air

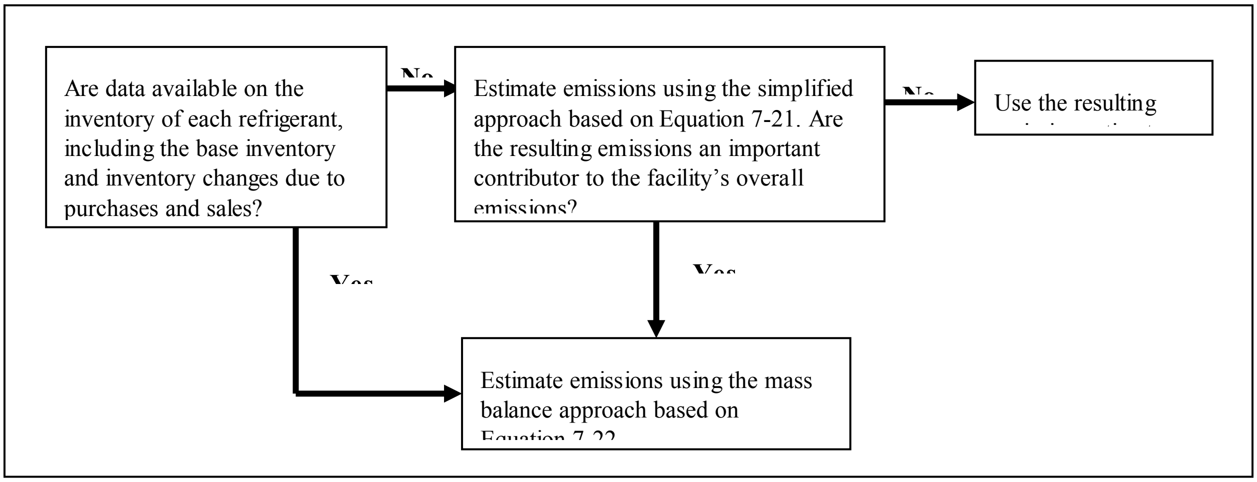

Figure 7-4. Refrigerant Emissions

A simplified estimation method for refrigerant emissions is based on knowing the type of refrigerant and type of equipment. Annual emissions are estimated by adjusting the total charge capacity of the equipment by an annual default leak rate, as shown in Equation 7-21 (WRI/WBCSD, 2005).

$$E_{\text{Refridgerants}} = \text{Equipment Charge (kg)} \times EF_{\text{Operating}} \times \frac{\text{tonne}}{1000\ \text{kg}} \qquad \text{(Equation 7-21)}$$

where

$E_{\text{Refrigerant}}$ = emission rate of the PFC or HFC from refrigeration equipment;

Equipment Charge = total full charge of equipment (kg); and

$EF_{\text{Operating}}$ = EF associated with the operating phase of the equipment.

Table 7-83 provides the default equipment capacities and operating leak rates for common types of refrigeration equipment. This assumes that the installation and disposal of the refrigeration or air conditioning equipment is not conducted by the oil and gas entity. Where this assumption is not

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conditioning equipment can be found in the following references: EPA, *Climate Leaders Greenhouse Gas Inventory Protocol, Core Module Guidance: Direct HFC and PFC Emissions from Use of Refrigeration and Air Conditioning Equipment,* (EPA, 2008); IPCC, *2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 3 Chapter 7: Emissions of Fluorinated Substitutes of Fluorinated Substitutes for Ozone Depleting Substances* (IPCC, 2019); and WRI/ WBCSD, *Calculating HFC and PFC Emissions from the Manufacturing, Installation, Operation and Disposal of Refrigeration & Air-conditioning Equipment (Version 1.0) Guide to Calculation Worksheets,* (WRI/WBCSD, January 2005).

valid, refer to Volume 3, Chapter 7 of the IPCC Guidelines (IPCC, 2019) for additional factors to include in the emission estimation approach.

Table 7-83. Default Operating Emission Factors for Refrigeration / Air Conditioning Equipment

Type of Equipment [a]	Charge (kg)	Lifetime (years) [b]	Initial Emission Rate (% of initial charge/year) [b]	Operating Emission Rate (% of initial charge/year) [b]
Domestic refrigeration	0.05 – 0.5	12 - 20	0.2 - 1	0.1 – 0.5
Stand-alone commercial applications	0.2 – 6	10 – 15	0.5 – 3	1 – 15
Medium & large commercial refrigeration	50 – 2,000	7 – 15	0.5 – 3	10 – 35
Transport refrigeration	3 – 8	6 – 9	0.2 – 1	15 – 50
Industrial refrigeration including cold storage and food processing	10 – 10,000	15 – 30	0.5 – 3	7 – 25
Chillers	10 – 2,000	15 – 30	0.2 – 1	2 – 15
Residential and commercial A/C, including heat pumps	0.5 – 100	10 – 20	0.2 – 1	1 – 10
Mobile air conditioning	5 – 6500 (maritime) 10 – 30 (railway) 4 – 18 (buses) 0.5 – 2 (other Mobile A/C)	9 – 16	0.2 – 0.5	5 – 20 (railway) 20 – 40 (maritime) 10 – 20 (other Mobile A/C)

Footnotes and Sources:

[a] IPCC, *2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 3, Chapter 7: Emissions of Fluorinated Substitutes for Ozone Depleting Substances*, Table 7.9, 2019. Operating emission factors are the high end of the reported range.

[b] Lower value for developed countries and higher value for developing countries.

Refrigerant emissions are then converted to CO_2e by applying the appropriate global warming potential factors. The IPCC AR5 global warming potentials for refrigerant blends are provided in Table 7-84 (IPCC, 2014).

Table 7-84. Global Warming Potentials for Refrigeration Blends

Refrigerant Blend	Global Warming Potential [a]	Refrigerant Blend	Global Warming Potential [a]	Refrigerant Blend	Global Warming Potential [a]
R-401A	18	R-409A	na	R-419A	2,688
R-401B	15	R-409B	na	R-420A	1,144
R-401C	21	R-410A	1,924	R-500	36
R-402A	1,902	R-410B	2,048	R-501	na
R-402B	1,205	R-411A	15	R-502	na
R-403A	1,780	R-411B	4	R-503	4,972
R-403B	3,471	R-412A	445	R-504	326
R-404A	3,943	R-413A	na	R-505	na
R-406A	na	R-414A	na	R-506	na
R-407A	1,923	R-414B	na	R-507 or R-507A	3,985
R-407B	2,547	R-415A	25	R-508A	na
R-407C	1,624	R-415B	104	R-508B	na
R-407D	1,487	R-416A	767	R-509 or R-509A	4,984
R-407E	1,425	R-417A	2,127		
R-408A	2,430	R-418A	3		

Source:

[a] Intergovernmental Panel on Climate Change (IPCC), Climate Change 2014: Synthesis Report. *Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change*. 2014. https://archive.ipcc.ch/report/ar5/syr/

Where refrigerant emissions are a significant part of an entity's GHG inventory (defined by most reporting programs as larger than 5% of the inventory), emissions from air conditioning equipment can be calculated using a mass balance approach, as shown in the following equation (WRI/WBCSD, 2005):

$$E_{FC_i} = S_{E,i} - S_{B,i} + P_i - S_i + \Delta C_i \qquad \text{(Equation 7-22)}$$

where

$E_{FC,i}$ = emission rate of fluorinated compound or refrigerant mixture *i;*

$S_{E,i}$ = quantity of refrigerant *i* in storage at the end of the year;

$S_{B,i}$ = quantity of refrigerant *i* in storage at the beginning of the year;

P_i = purchases/acquisitions of refrigerant *i* during the year;

S_i = sales/disbursements of refrigerant *i* during the year; and

ΔC_i = net change in total equipment volume for refrigerant i.

Equation 7-18 should be applied to each type of refrigerant or mixture used. Care should be taken that releases are not double counted (e.g., from reporting both refrigerant blend and individual refrigerant use). Emissions from refrigerant recharges should be accounted for in the year the recharge occurred. An example calculation for HFC emissions from air conditioning equipment is shown in Exhibit 7-8.

EXHIBIT 7-8: Sample Calculation for Air Conditioning HFC Emissions

INPUT DATA:

An oil and gas industry company owns and operates 680 vehicles utilizing Freon-134a (otherwise known as R-134a or HFC-134a). The vehicles range from small passenger vehicles to heavy-duty transport vehicles. Calculate the emissions by pollutant and as CO_2e.

CALCULATION METHODOLOGY:

Because the specific capacity of the vehicles is unknown, it is assumed that the median capacity of the vehicles is equal to the high-range capacity listed in Table 7-81. Using Equation 7-17, the estimated emissions would be:

$$E_{\text{R-134a}} = 680 \text{ vehicles} \times \frac{1.5 \text{ kg}}{\text{vehicle}} \times 0.2 \times \frac{\text{tonne}}{1000 \text{ kg}}$$

$$\underline{E_{\text{R-134a}} = 0.204 \text{ tonnes R-134a}}$$

$$E_{CO_2e} = 0.204 \text{ tonnes R-134a} \times \frac{1300 \text{ tonne } CO_2e}{\text{tonne R-134a}}$$

$$\underline{E_{CO_2e} = 265.2 \text{ tonne } CO_2e}$$

7.6.2 Electrical Equipment

Electrical transmission and distribution systems may use SF_6 as an insulator or interrupter, due to its dielectric strength. Sulfur hexafluoride may be found in substations, circuit breakers, and switchgears. A potential source of SF_6 emissions in the oil and gas industry is equipment leaks (e.g., through seals) and servicing of electrical transmission and distribution equipment, where an oil and gas company operates this equipment.

The US EPA GHGRP uses a similar mass balance approach for both PFC and SF_6 emissions quantification (EPA GHGRP, 2019), as shown in Equation 7-23.

$$E_{SF_6} = \text{Decrease}_{SF_6} + \text{Acquisition}_{SF_6} - \text{Disbursements}_{SF_6} - \text{Capacity}_{\text{Increase}} \qquad \text{(Equation 7-23)}$$

where

E_{SF6} = Annual emissions of SF6;

Decrease_{SF6} = Decrease in SF6 inventory = (mass of SF6 stored in containers, but not in energized equipment, at the beginning of the year) – (mass of SF6 stored in containers, but not in energized equipment, at the end of the year);

Acquisition_{SF6} = Acquisitions of SF6 = (mass of SF6 purchased in bulk) – (mass of SF6 purchased from equipment with or inside equipment, including hermetically sealed-pressure switchgear) + (mass of SF6 returned to facility after off-site recycling);

$\text{Disbursements}_{SF6}$ = Disbursements of SF6 = (mass of SF6 in bulk and contained in equipment that is sold to other entities) + (mass of SF6 returned to suppliers) + (mass of SF6 sent off site for recycling) + (mass of SF6 sent off-site for destruction); and

$\text{Capacity}_{\text{Increase}}$ = Net increase in total nameplate capacity of equipment operated = (the nameplate capacity of new equipment in mass units, including hermetically sealed-pressure switchgear) – (Nameplate capacity of retiring equipment in mass units, including hermetically sealed-pressure switchgear). (Note that Nameplate Capacity refers to the full and proper charge of equipment rather than to the actual charge, which may reflect leakage.)

If the data required to quantify SF_6 emissions using Equation 7-23 are not available or appropriate, electrical equipment-based SF_6 emissions can be calculated using either Equation 7-24 or 7-25. Equation 7-24 is appropriate in instances where electrical equipment that use SF_6 have been in use for 10-20 years or more, and emissions from sealed-pressure systems are likely to be negligible.

Equation 7-25 is appropriate for sealed-pressure equipment and all types of equipment where electrical equipment has been used for less than 10-20 years.

$$E_{SF_6} = (Q_{Recharge} - Q_{Recovered}) \qquad \text{(Equation 7-24)}$$

$$E_{SF_6} = (Q_{Recharge} - Q_{Recovered}) \times \sum C \times EF \qquad \text{(Equation 7-25)}$$

where

E_{SF_6} = annual emissions of SF_6;

$Q_{Recharge}$ = SF_6 used to recharge closed pressure equipment at servicing;

$Q_{Recovered}$ = SF_6 recovered from closed pressure equipment at servicing;

C = nameplate capacity of equipment installed, excluding equipment covered in ($Q_{Recharge} - Q_{Recovered}$); and

EF = usage based emission factor (see Table 7-85).

Usage-based emission factors for SF_6 emissions from electrical equipment are provided in Table 7-85.

Table 7-85. Usage-Based Fugitive Emission Factors for Electrical Equipment

Equipment	Region/Country	Reference Factor [a, b], Units	
Sealed pressure electrical equipment (MV Switchgear)	Europe	0.002	Fraction per year of nameplate capacity of all equipment installed
	Japan	0.007	
Closed pressure electrical equipment	Europe	0.026	
	Japan	0.007	
	U.S.	0.14[c]	
Gas insulated transformers	Japan	0.007	

Footnotes and Sources:

[a] IPCC. *2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 3, Chapter 8*, April 2007, Tables 8.2 through 8.4.

[b] Factors include leakage, major failures/arc faults and maintenance losses. Factors reflect the practices and technologies in place in 1995.

[c] Includes emissions from installation.

SF_6 emissions from electrical transmission and distribution can be calculated using Equation 7-26. Distance-based emission factors for SF_6 emissions from electrical transmission and distribution are provided in Table 7-86 (EPA, 2019b).

$$E_{SF_6} = TD \times EF \qquad \text{(Equation 7-26)}$$

where

E_{SF_6} = annual emissions of SF_6;

TD = transmission distance (mi), for lines carrying voltage at or above 34.5 kV; and

EF = distance based emission factor.

Table 7-86. Distance-Based Fugitive Emission Factors for Electrical Transmission and Distribution

Emission Basis	Reference Emission Factor, Original Units [a]		Emission Factor, Converted Units	
Average US electrical transmission (2019 data)	0.226	kg SF_6/mi-yr	2.26E-04	tonne SF_6/mi-yr
			1.40E-04	tonne SF_6/km-yr

Footnote and Source:

[a] EPA. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2019*, April 2021, pg. 4-143. Data are based on reported emissions under US EPA GHGRP.

Exhibit 7-9 presents an example of calculating SF_6 emissions using the major equipment emission factors approach.

EXHIBIT 7-9: Sample Calculation for Electrical Equipment Emissions

INPUT DATA:

A company specializing in the delivery of natural gas and electricity operates 135 miles of electric transmission and distribution lines (at or above 34.5 kV), with various electrical equipment used to support electric transmission and distribution. The company uses SF_6 for electrical insulation and current interruption.

Service records for the past year indicate that a total of 79,878 lb SF_6 was used to recharge electrical equipment, while a total of 79,480 lb SF_6 was recovered from electrical equipment. Calculate the SF_6 and CO_2e emissions using both the equipment usage methodology and transmission mileage methodology, for comparison purposes.

CALCULATION METHODOLOGY:

1. *Calculate emissions associated with the equipment.* Emissions of SF_6 are calculated using a material balance.

$$E_{SF_6} = \frac{(79{,}878 - 79{,}480)\text{ lb}}{\text{yr}} \times \frac{\text{tonne}}{2204.62\text{ lb}} = \underline{0.18\text{ tonne SF}_6/\text{yr}}$$

CO_2e emissions are calculated using Equation 3-2 using GWPs from the IPCC Fifth Assessment Report.

$$E_{COe} = \frac{0.18\text{ tonne SF}_6}{\text{yr}} \times \frac{23{,}500\text{ tonne CO}_2}{\text{tonne SF}_6}$$

$$E_{COe} = 4{,}230\text{ tonne CO}_2\text{e}$$

2. *Calculate emissions using associated with transmission mileage.* Using Equation 7-6 (for mileage based emissions) and the global warming potential from Table 3-1, the estimated emissions would be:

EXHIBIT 7-9: Sample Calculation for Electrical Equipment Emissions, continued

$$E_{SF_6} = 135 \text{ miles} \times \frac{0.226 \text{ kg}}{\text{mile} - \text{yr}} \times \frac{\text{tonne}}{1{,}000 \text{ kg}} = 0.031 \text{ tonne } SF_6/\text{yr}$$

CO_2e emissions are calculated using Equation 3-2.

$$E_{COe} = \frac{0.031 \text{ tonne } SF_6}{\text{yr}} \times \frac{23{,}500 \text{ tonne } CO_2}{\text{tonne } SF_6}$$

$$E_{COe} = 717.0 \text{ tonne } CO_2e$$

Note the difference between the emissions calculated with the two methods. As with any methodology, a mass balance approach will be more accurate than the use of emission factors.

7.6.3 SF_6 Emissions from Pipeline Operations

Natural gas pipeline operations may use SF_6 as a tracer gas to detect leaks. Emissions from these activities can be determined using a mass balance approach, similar to that shown for refrigerant emissions:

$$E_{SF_6} = S_E - S_B + P - S + \Delta C \qquad \text{(Equation 7-27)}$$

where

E_{SF_6} = emission rate of SF_6;

S_E = quantity of SF_6 in storage at the end of the year;

S_B = quantity of SF_6 in storage at the beginning of the year;

P = purchases/acquisitions of SF_6 during the year;

S = sales/disbursements of SF_6 during the year; and

ΔC = net change in total equipment SF_6 volume.

Alternatively, SF_6 emissions can be determined by scaling pipeline fugitive CH_4 emissions based on the relative concentration of SF_6 in the gas compared to CH_4, similar to the adjustment shown in Equation 7-1 for CO_2 emissions.

7.7 References

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Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Natural Gas and Oil Industry

Section 8 – Indirect Emissions Estimation Methods

November 2021

Table of Contents

List of Tables

List of Figures

8.0 INDIRECT EMISSIONS ESTIMATION METHODS

Indirect emissions are emissions that are a consequence of activities of the reporting company, but which result from sources owned or controlled by another party (WRI, 2015). This section addresses indirect emissions from the purchase of energy, also referred to as Scope 2 emissions. Carbon dioxide, CH_4, and N_2O are emitted when fuel is combusted to generate electricity or to produce heat, steam, or cooling. This section provides methodologies for estimating the emissions associated with these activities, where these energy sources are generated off site and purchased for use on site. In addition, this section addresses the allocation of emissions among co-produced energy streams, such as those associated with the cogeneration of electricity and steam. For transparency, indirect energy emissions, also referred to as Scope 2, should be reported separately from Scope 1 direct emissions (WRI, 2005).

To address the increasing prevalence of renewable energy purchases, the World Resources Institute (WRI) established two distinct methods for Scope 2 accounting: a 'location-based' method that reflects the average emissions intensity of local or regional electric grids, and a 'market-based' method that reflects the emissions from the purchase or sale of electricity via contractual instruments, such as energy attribute certificates, direct contracts, etc. The *GHG Protocol Scope 2 Guidance* specifies that companies with any operations in markets providing product or supplier-specific data in the form of contractual instruments shall report Scope 2 emissions in two ways, using the location-based and market-based methods, respectively. The GHG estimation methodologies associated with each method include:

- Location-based method applies a grid average emission factor for the given region of electricity generation;
- Market-based method applies generation-specific emissions for the electricity purchased through any type of contract between two parties for the same and purchase of electricity, including Energy Attribute Certificates (EACs)[1], direct contracts, supplier-specific emission rates, and other default emission factors representing the untracked or unclaimed energy and emissions, also called the 'residual mix' (WRI, 2015).

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[1] Energy Attribute Certificates (EACs) are contractual instruments for the electricity at the point of generation and include Guarantee of Origin (GO) certificates in Europe and Renewable Energy Certificates (RECs) in the US and Canada.

In regions where differentiated energy products in the form of contractual instruments are available in a given market, which may or may not be for green power or renewable energy, the residual mix represents the emissions rate left after EACs, direct contracts such as power purchase agreements (PPAs), and supplier-specific emission rates are removed from the system. If the residual mix emission factors are not available, grid average factors are used. For guidance on applying the location-based and market-based Scope 2 accounting approaches, refer to the *GHG Protocol Scope 2 Guidance* (WRI, 2015).

8.1 Emissions Associated with Purchased or Imported Energy

Figure 8-1 provides a decision tree for selecting an approach for estimating emissions associated with purchased electricity. As shown, the emission estimation approach for purchased or imported electricity varies depending on whether the power was purchased from the grid or from a known generator through a contractual instrument. As shown in Figure 8-1, the calculation approaches that are associated with a contractual arrangement for electricity with the supplier, including EACs, direct contracts, etc., are classified as market-based methods. If the electricity purchased is generated in a region that offers EACs, but the emission information is unknown, a residual mix default emission factor can be applied (and is also classified as a market-based method). Where electricity purchased from the grid where an average grid emission factor is applied at either a regional or national level, the calculation approach is classified as a location-based method (however, average grid emission factors are used in the market based approach when residual mix factors are unavailable). A consistent approach should be used across all operations within the inventory: either a market based approach or a location based approach for the entire inventory.

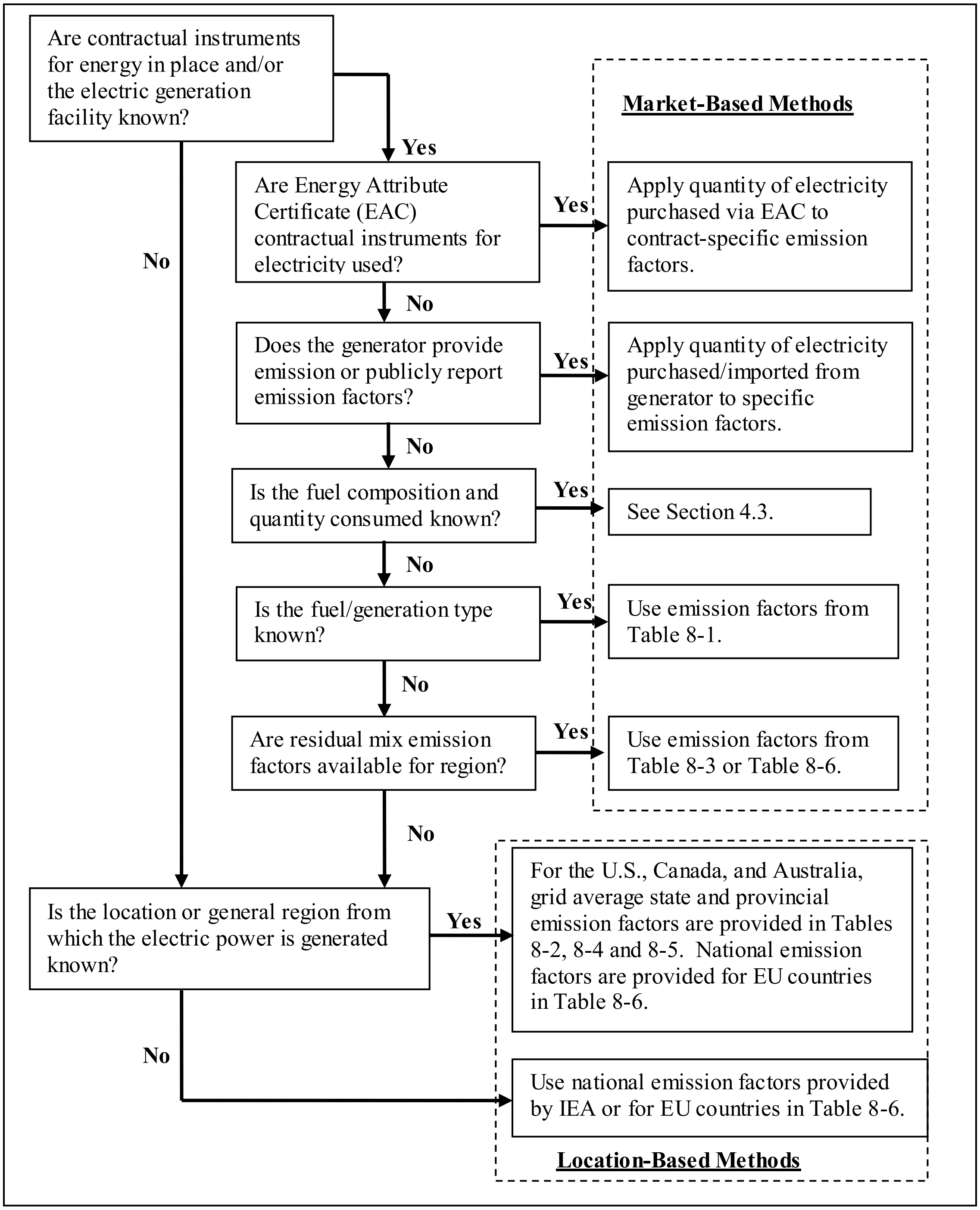

Figure 8-1. Decision Tree for Purchased Electricity Emissions

8.1.1 Electricity from a Known Generator

It is often difficult to track purchased electricity back to the source. However, where electricity is supplied from a known generator or through a contractual instrument (including direct contracts, certificates such as Renewable Energy Credits (RECs) and Guarantees of Origin (GOs), or supplier-specific information), emissions associated with purchased or imported electricity can be based on fuel-derived emission factors provided in the contractual instrument or by the generator or fuel data using the combustion emission approach presented in Section 4.3. Figure 8-1 depicts several approaches to estimate indirect emissions from electricity. The market-based approaches are based on having generation facility data such as publicly reported emissions factors, fuel composition and quantity consumed, and fuel/generation type, or knowing the region from which the electricity is generated. If only general information is available on the type of fuel and combustion method, Table 8-1 provides CO_2, CH_4, and N_2O emission factors for electricity generation on a power consumed basis (megawatt-hours) from the U.S. EIA or the U.S. DOE (EIA, 2007; DOE, 1994).

Table 8-1. Electricity Usage Emission Factors by Method of Generation

		Carbon Dioxide [a]		Methane [b]		Nitrous Oxide [b]	
Method of Generation	**Fuel Type**	**lb/ 10^6 W-hr**	**tonnes/ 10^6 W-hr**	**lb/ 10^6 W-hr**	**tonnes/ 10^6 W-hr**	**lb/ 10^6 W-hr**	**tonnes/ 10^6 W-hr**
Advanced combustion turbine	Natural Gas	1,102.31	0.50	No Data			
	Distillate Oil	1,499.14	0.68	No Data			
	Residual Oil	1,609.37	0.73	No Data			
Advanced gas / oil combined cycle	Natural Gas	815.71	0.37	No Data			
	Distillate Oil	1,124.36	0.51	No Data			
	Residual Oil	1,212.54	0.55	No Data			
Combined cycle [c]	Natural Gas	881.85	0.40	0.015	6.80E-06	0.063	2.86E-05
	Distillate Oil	1,190.49	0.54	0.013	5.90E-06	0.268	1.22E-04
	Residual Oil	1,300.73	0.59	0.013	5.90E-06	0.268	1.22E-04
Combustion turbine [d]	Natural Gas	1,278.68	0.58	0.16	7.26E-05	0.24	1.09E-04
	Distillate Oil	1,741.65	0.79	0.021	9.53E-06	0.276	1.25E-04
	Residual Oil	1,873.93	0.85	0.021	9.53E-06	0.276	1.25E-04
Distributed generation - baseload	Natural Gas	1,102.31	0.50	No Data			
	Distillate Oil	1,499.14	0.68	No Data			
	Residual Oil	1,609.37	0.73	No Data			
Distributed generation - peak	Natural Gas	1,212.54	0.55	No Data			
	Distillate Oil	1,653.47	0.75	No Data			
	Residual Oil	1,785.74	0.81	No Data			
Fuel cells	Natural Gas	881.85	0.40	No Data			
Geothermal – unspecified		268.96	0.122 [e]	No Data			
Geothermal – unspecified		-	0.073 (tCO_2e/MWh) [i]	Included in CO2e factor			
Geothermal – all, including binary		180 [f]	0.0816	1.66E-03 [f]	7.53E-07	No Data	
Geothermal – flash/dry steam		56.7	0.0257	No Data			
Integrated coal – gasification combined cycle	Coal	1,653.47	0.75	No Data			
Municipal solid waste boiler [g]		3,747	1.70	0.02	9.07E-06	0.55	2.49E-04
Pulverized coal	Coal	1,970	0.89	0.04	1.81E-05	0.34	1.54E-04
Renewables (wind, hydro, solar, and nuclear)		0	0	0	0	0	0
Scrubbed coal	Coal	1,851.88	0.84	No Data			
Steam turbine	Natural Gas	968	0.44	0.05	2.27E-05	0	0
	Oil	1,452	0.66	0.002	9.07E-07	0	0
Wood waste biomass boiler [h]		3,400	1.54	0.14	6.35E-05	0.55	2.49E-04

Footnotes and Sources:

[a] Emission factors taken from U.S. Energy Information Administration, *Technical Guidelines Voluntary Reporting of Greenhouse Gases (1605(b)) Program*, Table 1.F.3, January 2007, unless otherwise noted. Only CO_2 emission factors are available for these Generator Types.

[b] U.S. Department of Energy, *Sector-Specific Issues and Reporting Methodologies Supporting the General Guidelines for the Voluntary Reporting of Greenhouse Gases under Section 1605(b) of the Energy Policy Act of 1992, Appendix B, DOE/PO-0028*, Washington, D.C., October 1994.

[c] Gas - Combined Cycle CH_4 and N_2O factors used for Natural Gas; Oil - Combined Cycle CH_4 and N_2O factors used for both distillate oil and residual oil.

[d] Gas - Combustion Turbine CH_4 and N_2O factors used for Natural Gas; Oil - Combustion Turbine CH_4 and N_2O factors used for both distillate oil and residual oil.

[e] Factor for unspecified plant type. Source: International Geothermal Association (Bertani and Thain, 2001).

[f] Factors for all geothermal plant types (including binary). Source: Geothermal Resources Council (Bloomfield and Moore, 1999).

[g] Municipal solid waste normally contains inorganic materials—principally plastics—that contain carbon that is not biogenic. The proportion of plastics in municipal solid waste varies considerably depending on climate, season, socio-economic factors, and waste management practices. As a result, EIA does not estimate a non-biogenic CO_2 emission factor for municipal solid waste.

[h] Under international GHG accounting methods developed by the IPCC, CO_2 emissions from biogenic combustion is reported separately from the other scopes. However, the emissions of CH_4 and N_2O are reported as part of Scope 2 emissions from purchased energy generated from biomass.

[i] McLean, K, et al. *Greenhouse gas emissions from New Zealand geothermal: power generation and industrial direct use*. Proceedings, 42nd New Zealand Geothermal Workshop, Waitangi, New Zealand, 24-26 November 2020. https://nzgeothermal.org.nz/geothermal-energy/emissions/. Emission factor in units of tonnes CO2e/MWh for 2019.

Note that these emission factors do not include transmission and distribution losses, but are applicable to megawatt-hr of metered electricity usage. Emissions resulting from transmission and distribution losses are accounted for by the entity that owns the transmission or distribution service lines. As such, any losses that occur downstream of the customer meter are incorporated into the customer's emission inventory by basing the emission estimate on the metered energy usage. Exhibit 8.1 demonstrates the use of the generation-based emission factors provided in Table 8-1.

EXHIBIT 8.1: Sample Calculation for Electric Utility (Indirect) Emissions Using Generation-based Emission Factors

INPUT DATA:

A facility purchases 500,000 kilowatt-hrs of electricity during a given year generated from an offsite natural gas combined-cycle system. Calculate the CO_2, CH_4, and N_2O emissions.

CALCULATION METHODOLOGY:

Emission factors for a natural gas combined-cycle system are provided in Table 7-1. The emission factors are multiplied by the quantity of electricity purchased to calculate the annual emissions, as follows:

$$E_{CO_2} = \frac{500{,}000 \text{ kilowatt-hr}}{\text{yr}} \times \frac{1 \text{ megawatt}}{1000 \text{ kilowatt}} \times \frac{0.40 \text{ tonne } CO_2}{\text{megawatt-hr}}$$

$$\underline{E_{CO_2} = 200 \text{ tonnes } CO_2/\text{yr}}$$

$$E_{CH_4} = \frac{500{,}000 \text{ kilowatt-hr}}{\text{yr}} \times \frac{1 \text{ megawatt}}{1000 \text{ kilowatt}} \times \frac{6.80 \times 10^{-6} \text{ tonne } CH_4}{\text{megawatt-hr}}$$

$$\underline{E_{CH_4} = 0.0034 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{N_2O} = \frac{500{,}000 \text{ kilowatt-hr}}{\text{yr}} \times \frac{1 \text{ meagwatt}}{1000 \text{ kilowatt}} \times \frac{2.86 \times 10^{-5} \text{ tonne } CO_2}{\text{megawatt-hr}}$$

$$\underline{E_{N_2O} = 0.0143 \text{ tonnes } N_2O/\text{yr}}$$

In the U.S., general emission factors from EPA can be applied if the generator of purchased electricity is known but fuel-based data are not available. Currently, EPA maintains a database with information from virtually every power plant and company that generates electricity in the U.S. (eGRID). The database is available at the following website:

https://www.epa.gov/egrid/data-explorer[2]

The database is a comprehensive inventory of environmental attributes of electric power systems, integrating information from both utility and non-utility companies. eGRID is based on available plant-specific data for all U.S. electricity generating plants that provide power to the electric grid and report data to the U.S. government. The database provides CO_2, CH_4, and N_2O emission rates (in addition to NOx, SO_2, and Hg) in terms of boiler, generator, power plant, electric generating company, parent company, state, power control area, and North American Electric Reliability Council (NERC) region.

Ideally, the emissions would be based on the most detailed information available. For example, if a facility knew that the electricity was primarily supplied by a specific power plant, emissions data at this level would provide the highest accuracy. If company-specific information were not available, state or regional grid average values would be appropriate.

8.1.2 Purchased Electricity from an Unknown Generator – State or Regional Basis

In the case where electricity is imported directly from a third party power supplier, generation and fuel information may not be available in all cases. Where the detailed data are unavailable, the default approach is to assume that the electricity was supplied from the grid. Regional or national grid emission factors may be available from federal governments.

Since electric transmission and distribution lines do not adhere to state boundaries, it is often difficult to identify a specific generation source. In the U.S., the EPA’s eGRID database provides GHG emission factors based on electric generation from all electricity generating plants that provide power to the electric grid and report to the U.S. government. eGRID provides available data on specific electric generation plants, as well as regional grid averages. eGRID subregions are subsets of NERC regions, with similar emissions and resource mix characteristics. eGRID emission factors are summarized in Table 8-2, with the corresponding subregions illustrated in Figure 8-2. These mission factors are grid averages that account for all generation, aligned with the location-based method for Scope 2 accounting. Subregions can also be determined by ZIP code using the EPA

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[2] Accessed September 15, 2021.

Power Profiler Tool, which can be found at the following address:
https://www.epa.gov/egrid/power-profiler#/ [3]

Note that these emission factors are for the year 2019, the most current data at the time of publication. When possible, electric grid emission factors corresponding to the emissions inventory year should be applied. The most recent eGRID information can be found online at:

https://www.epa.gov/egrid/data-explorer[4]

The EIA provides additional information related to energy generation emissions in the U.S., such as electric generation by independent power producers, and electric generation by fuel type[5].

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[3] Accessed September 14, 2021.
[4] Accessed September 16, 2021.
[5] https://www.eia.gov/electricity/annual/, accessed September 16, 2021.

Table 8-2. Average U.S. Electricity Usage Emission Factors by eGRID Subregion - 2019 [a]

eGRID Subregion Acronym	eGRID Subregion Name	CO_2 Output Emission Rate			CH_4 Output Emission Rate			N_2O Output Emission Rate		
		(lb/MWh)	(ton/MWh)	(tonne/MWh)	(lb/MWh)	(ton/MWh)	(tonne/MWh)	(lb/MWh)	(ton/MWh)	(tonne/MWh)
AKGD	ASCC Alaska Grid	1,114.4	0.557	0.505	0.098	4.90E-05	4.44E-05	0.013	6.50E-06	5.90E-06
AKMS	ASCC Miscellaneous	549.3	0.275	0.249	0.026	1.30E-05	1.18E-05	0.004	2.00E-06	1.81E-06
AZNM	WECC Southwest	952.3	0.476	0.432	0.068	3.40E-05	3.08E-05	0.010	5.00E-06	4.54E-06
CAMX	WECC California	453.2	0.227	0.206	0.033	1.65E-05	1.50E-05	0.004	2.00E-06	1.81E-06
ERCT	ERCOT All	868.6	0.434	0.394	0.057	2.85E-05	2.59E-05	0.008	4.00E-06	3.63E-06
FRCC	FRCC All	861.0	0.431	0.391	0.055	2.75E-05	2.49E-05	0.007	3.50E-06	3.17E-06
HIMS	HICC Miscellaneous	1,185.6	0.593	0.538	0.143	7.15E-05	6.49E-05	0.022	1.10E-05	9.98E-06
HIOA	HICC Oahu	1,694.5	0.847	0.769	0.185	9.25E-05	8.39E-05	0.028	1.40E-05	1.27E-05
MROE	MRO East	1,502.6	0.751	0.682	0.147	7.35E-05	6.67E-05	0.022	1.10E-05	9.98E-06
MROW	MRO West	1,098.4	0.549	0.498	0.119	5.95E-05	5.40E-05	0.017	8.50E-06	7.71E-06
NEWE	NPCC New England	488.9	0.244	0.222	0.077	3.85E-05	3.49E-05	0.010	5.00E-06	4.54E-06
NWPP	WECC Northwest	715.2	0.358	0.324	0.068	3.40E-05	3.08E-05	0.010	5.00E-06	4.54E-06
NYCW	NPCC NYC/Westchester	553.8	0.277	0.251	0.021	1.05E-05	9.52E-06	0.002	1.00E-06	9.07E-07
NYLI	NPCC Long Island	1,209.0	0.604	0.548	0.157	7.85E-05	7.12E-05	0.020	1.00E-05	9.07E-06
NYUP	NPCC Upstate NY	232.3	0.116	0.105	0.017	8.50E-06	7.71E-06	0.002	1.00E-06	9.07E-07
PRMS	Puerto Rico Miscellaneous	1,537.3	0.769	0.697	0.084	4.20E-05	3.81E-05	0.013	6.50E-06	5.90E-06
RFCE	RFC East	695.0	0.348	0.315	0.053	2.65E-05	2.40E-05	0.007	3.50E-06	3.17E-06
RFCM	RFC Michigan	1,189.3	0.595	0.539	0.114	5.70E-05	5.17E-05	0.016	8.00E-06	7.26E-06
RFCW	RFC West	1,067.7	0.534	0.484	0.099	4.95E-05	4.49E-05	0.014	7.00E-06	6.35E-06
RMPA	WECC Rockies	1,242.6	0.621	0.564	0.117	5.85E-05	5.31E-05	0.017	8.50E-06	7.71E-06
SPNO	SPP North	1,070.0	0.535	0.485	0.112	5.60E-05	5.08E-05	0.016	8.00E-06	7.26E-06
SPSO	SPP South	1,002.0	0.501	0.454	0.070	3.50E-05	3.17E-05	0.010	5.00E-06	4.54E-06
SRMV	SERC Mississippi Valley	806.8	0.403	0.366	0.043	2.15E-05	1.95E-05	0.006	3.00E-06	2.72E-06
SRMW	SERC Midwest	1,584.4	0.792	0.719	0.169	8.45E-05	7.67E-05	0.025	1.25E-05	1.13E-05
SRSO	SERC South	969.2	0.485	0.440	0.071	3.55E-05	3.22E-05	0.010	5.00E-06	4.54E-06
SRTV	SERC Tennessee Valley	949.7	0.475	0.431	0.087	4.35E-05	3.95E-05	0.013	6.50E-06	5.90E-06
SRVC	SERC Virginia/Carolina	675.4	0.338	0.306	0.058	2.90E-05	2.63E-05	0.008	4.00E-06	3.63E-06
U.S. Average		**884.2**	**0.442**	**0.401**	**0.075**	**3.75E-05**	**3.40E-05**	**0.011**	**5.50E-06**	**4.99E-06**

Footnotes and Source:

[a] U.S. EPA. Emissions &Generation Resource Integrated Database (eGRID), February 2021. https://www.epa.gov/egrid. Emission factors were converted from units of lb/MWh to units of ton/MWh and tonne/MWh. 2019 was the most recent year for which emission factors were available, as of the time of publication.

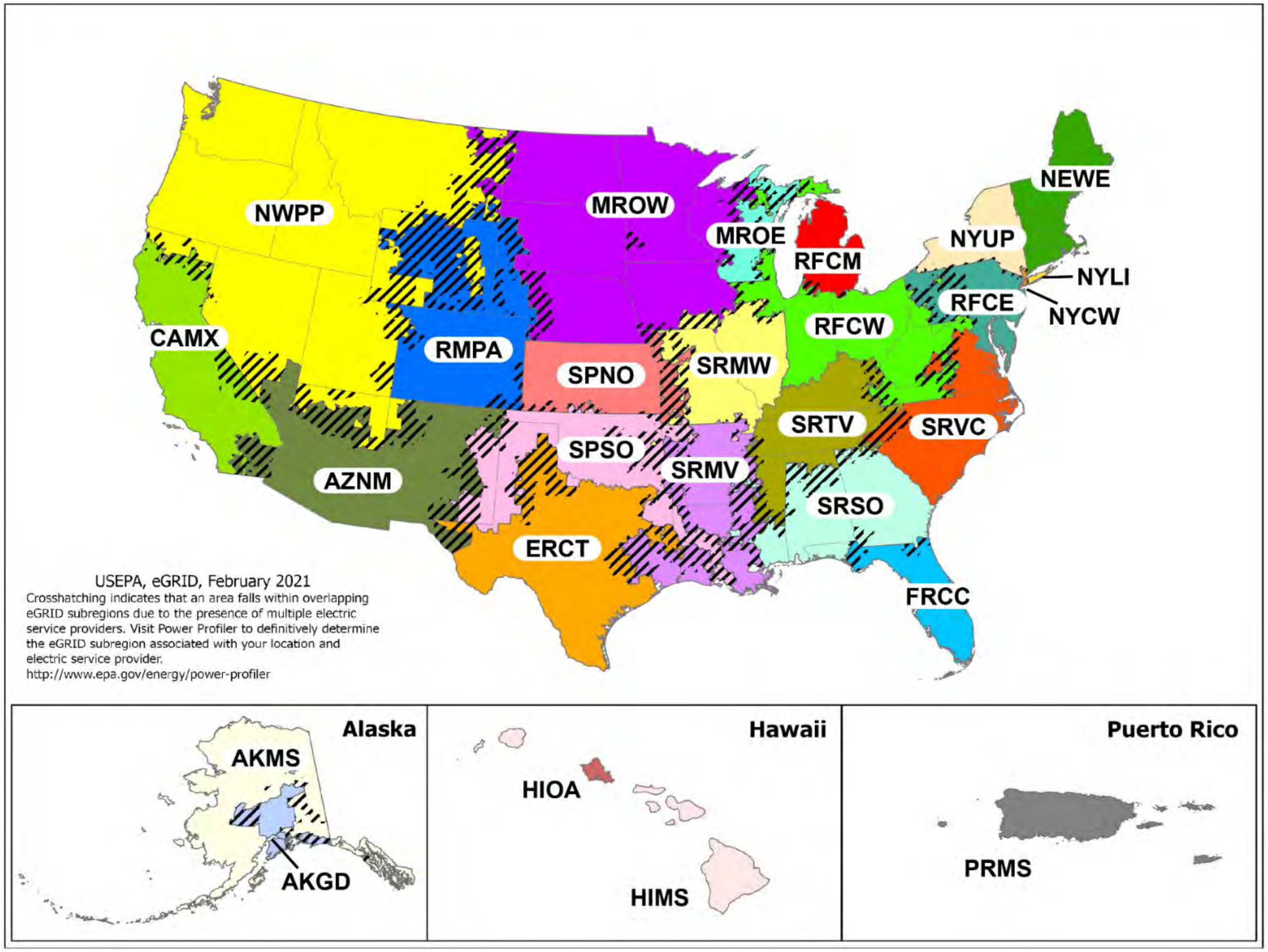

Figure 8-2. eGRID Subregion Map

Source:
U.S. EPA. *eGRID2019 Year 2019 GHG Annual Output Emission Rates*, February 2021, https://www.epa.gov/egrid

Table 8-3 presents residual mix emission factors for the U.S. electrical grid subregions. The residual mix emission factors represent the average emissions rate left after EACs, direct contracts such as PPAs, and supplier-specific emission rates are removed from the system. The residual mix emission factors in Table 8-3 would be used in the U.S. when accounting for Scope 2 emissions aligned with the market-based method when the generator is unknown.

Table 8-3. U.S. Subregion Residual Mix Electricity CO_2 Emission Factors – 2019 [a]

eGRID Subregion Acronym	eGRID Subregion Name	Residual Mix CO_2 Emission Factors		
		Original Units	Converted Units	
		lbs $CO_2/10^6$ W-hr	ton $CO_2/10^6$ W-hr	tonnes $CO_2/10^6$ W-hr
AKGD	ASCC Alaska Grid	1,126.04	0.5630	0.5108
AKMS	ASCC Miscellaneous	549.31	0.2747	0.2492
AZNM	WECC Southwest	954.89	0.4774	0.4331
CAMX	WECC California	461.46	0.2307	0.2093
ERCT	ERCOT All	927.31	0.4637	0.4206
FRCC	FRCC All	867.37	0.4337	0.3934
HIMS	HICC Miscellaneous	1,185.60	0.5928	0.5378
HIOA	HICC Oahu	1,694.54	0.8473	0.7686
MROE	MRO East	1,502.60	0.7513	0.6816
MROW	MRO West	1,149.60	0.5748	0.5215
NEWE	NPCC New England	490.94	0.2455	0.2227
NWPP	WECC Northwest	733.82	0.3669	0.3329
NYCW	NPCC NYC/Westchester	553.8	0.2769	0.2512
NYLI	NPCC Long Island	1,208.98	0.6045	0.5484
NYUP	NPCC Upstate NY	232.36	0.1162	0.1054
PRMS	Puerto Rico Miscellaneous	1,554.21	0.7771	0.7050
RFCE	RFC East	695.24	0.3476	0.3154
RFCM	RFC Michigan	1,189.95	0.5950	0.5398
RFCW	RFC West	1,068.07	0.5340	0.4845
RMPA	WECC Rockies	1,274.88	0.6374	0.5783
SPNO	SPP North	1,147.55	0.5738	0.5205
SPSO	SPP South	1,185.98	0.5930	0.5380
SRMV	SERC Mississippi Valley	808.45	0.4042	0.3667
SRMW	SERC Midwest	1,592.27	0.7961	0.7222
SRSO	SERC South	975.84	0.4879	0.4426
SRTV	SERC Tennessee Valley	949.91	0.4750	0.4309
SRVC	SERC Virginia/Carolina	678.35	0.3392	0.3077

Footnotes and Source:

[a] Green-e. 3032 Green-e Residual Mix Emissions Rates (2019 data). https://www.green-e.org/2021-residual-mix. Emission factors were converted from units of lb/MWh to units of ton/MWh and tonne/MWh. 2019 was the most recent year for which emission factors were available, as of the time of publication. https://www.green-e.org/2021-residual-mix. Emission factors were converted from units of lb/MWh to units of ton/MWh and tonne/MWh. 2019 was the most recent year for which emission factors were available, as of the time of publication.

The Australian Government publishes grid average emission factors for purchased electricity according to state, territory, or grid description, as shown in Table 8-4.

Table 8-4. Grid Average Australian Electricity Usage Emission Factors - 2020

Location	CO_2 Equivalent (CO_2 eq.) [a]
	tonnes/10^6 W-hr
New South Wales and Australian Capital Territory	0.81
Victoria	0.98
Queensland	0.81
South Australia	0.43
South West Interconnected System (SWIS) in Western Australia	0.68
North Western Interconnected System (NWIS) in Western Australia	0.58
Darwin Katherine Interconnected System (DKIS) in the Northern Territory	0.53
Tasmania	0.17
Northern Territory	0.62

Footnote and Source:
[a] Australian Government, Department ofIndustry, Science, Energy and Resources, *National Greenhouse Accounts Factors*, Table 5, October 2020. Original source units are kg/kW-hr. Note that these factors are revised annually by the Australian Government.

Environment Canada provides grid average emission factors for purchased electricity according to province. These factors are shown in Table 8-5.

Table 8-5. Grid Average Canadian Electricity Usage Emission Factors by Province (2018 data) [a]

	CO_2		CH_4		N_2O	
Location	**g/ kW-hr**	**tonnes/ MW-hr**	**g/ kW-hr**	**tonnes/ MW-hr**	**g/ kW-hr**	**tonnes/ MW-hr**
Newfoundland and Labrador	40	0.0400	0.0006	6.00E-07	0.001	1.00E-06
Prince Edward Island	14	0.0140	0.0005	5.00E-07	0.0002	2.00E-07
Nova Scotia	680	0.6800	0.03	3.00E-05	0.01	1.00E-05
New Brunswick	260	0.2600	0.02	2.00E-05	0.004	4.00E-06
Quebec	1.2	0.0012	0.0	0	0.00	0
Ontario	20	0.0200	0.004	4.00E-06	0.001	1.00E-06
Manitoba	1.9	0.0019	0.0001	1.00E-07	0.00	0
Saskatchewan	660	0.6600	0.05	5.00E-05	0.02	2.00E-05
Alberta	750	0.7500	0.04	4.00E-05	0.01	1.00E-05
British Columbia	9.5	0.0095	0.003	3.00E-06	0.0007	7.00E-07
Northwest Territories	150	0.1500	0.01	1.00E-05	0.00	0
Yukon	49	0.0490	0.003	3.00E-06	0.00	
Nunavut	720	0.7200	0.0	0	0.0	0

Footnote and Source:

[a] Environment Canada, National Inventory Report, 1990-2018: Greenhouse Gas Sources and Sinks in Canada (April 2020) Annex 13: Emission Factors, Table A13-2 - A13-14. (Cited by The Climate Registry, *2021-Default-Emission-Factor-Document.pdf,* Table 3.2, May 2021.) Factors do not include emissions from transmission and distribution losses. Emission factors were converted from units of g/kW-hr to units of tonne/MW-hr.

An example calculation illustrating how to estimate electricity-related CO_2, CH_4 and N_2O emissions using regional or provincial emission factors follows in Exhibit 8.2.

EXHIBIT 8.2: Sample Calculation for Electric Utility (Indirect) Emissions Using State Emission Factors

INPUT DATA:
A facility in Colorado purchases 500,000 kilowatt-hr of electricity during a given year. The method of electricity generation is unknown, but the electricity is produced in Colorado. Calculate the annual CO_2, CH_4 and N_2O emissions.

CALCULATION METHODOLOGY:
From Figure 8-2, the only eGRID subregion serving Colorado is RMPA. With this knowledge, emission factors are taken from Table 8-2 for eGRID subregion RMPA. Annual emissions are calculated by multiplying the emission factors by the quantity of electricity purchased by the plant, as follows:

$$E_{CO_2} = \frac{500{,}000\ \text{kilowatt}-\text{hr}}{\text{yr}} \times \frac{1\ \text{megawatt}}{1{,}000\ \text{kilowatt}} \times \frac{0.564\ \text{tonne}\ CO_2}{\text{megawatt}-\text{hr}}$$

$$E_{CO_2} = 282.0\ \text{tonnes}\ CO_2/\text{yr}$$

$$E_{CH_4} = \frac{500{,}000 \text{ kilowatt} - \text{hr}}{\text{yr}} \times \frac{1 \text{ megawatt}}{1{,}000 \text{ kilowatt}} \times \frac{5.31 \times 10^{-5} \text{ tonne } CH_4}{\text{megawatt} - \text{hr}}$$

$$E_{CH_4} = 0.0266 \text{ tonnes } CH_4/\text{yr}$$

$$E_{N_2O} = \frac{500{,}000 \text{ kilowatt} - \text{hr}}{\text{yr}} \times \frac{1 \text{ megawatt}}{1{,}000 \text{ kilowatt}} \times \frac{7.71 \times 10^{-6} \text{ tonne } N_2O}{\text{megawatt} - \text{hr}}$$

$$E_{N_2O} = 0.0039 \text{ tonnes } N_2O/\text{yr}$$

8.1.3 Purchased Electricity from an Unknown Generator – National Basis

In the United States, Canada, and Australia, regional data (*e.g.*, Figure 8-2, eGRID subregion map) should be used over national emission factors, if possible, when the generation is unknown. For countries where regional data is unavailable, national grid average emissions factors can be used, aligned with the location-based method for Scope 2 reporting. National grid average emission factors for CO_2, CH_4, and N_2O are published annually in a database by the International Energy Agency (IEA). The grid average national production emission factors represent all electric production within the country-specific national borders. The IEA database can be purchased online at:

https://www.iea.org/data-and-statistics/data-products/?filter=emissions
https://www.iea.org/data-and-statistics/data-product/emissions-factors-2021[6]

Published grid average and residual mix CO_2 emission factors are available for EU countries that can be accessed at the following website:

https://www.aib-net.org/sites/default/files/assets/facts/residual-mix/2020/AIB_2020_Residual_Mix_Results.pdf[7]

Table 8-6 presents both the grid average and the residual mix emission factors on a CO_2 equivalent basis for EU countries for year 2020.

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[6] Link to purchase emission factors published in 2021.
[7] Accessed September 15, 2021.

Table 8-6. Electrical Grid CO_2 Emission Factors for European Countries – 2020[a]

Country Code	Country	Grid Average CO_2 Emission Factors [b]		Residual Mix CO_2 Emission Factors [c]	
		g CO_2/ 10^3 W-hr	tonne CO_2/ 10^6 W-hr	g CO_2/ 10^3 W-hr	tonne CO_2/ 10^6 W-hr
AT	Austria	111.18	0.1112	-	-
BE	Belgium	161.89	0.1619	204.78	0.2048
BG	Bulgaria	372.12	0.3721	372.12	0.3721
CH	Switzerland	11.52	0.0115	30.34	0.0303
HR	Croatia	226.96	0.2270	468.8	0.4688
CY	Cyprus	642.9	0.6429	642	0.6420
CZ	Czech Republic	495.49	0.4955	532.44	0.5324
DK	Denmark	142.52	0.1425	427.67	0.4277
EE	Estonia	598.69	0.5987	546.89	0.5469
FI	Finland	95.32	0.0953	268.18	0.2682
FR	France	51.28	0.0513	58.52	0.0585
DE	Germany	338.66	0.3387	588.83	0.5888
GR	Greece	410.01	0.4100	490.4	0.4904
HU	Hungary	243.75	0.2438	274.11	0.2741
IE	Ireland	335.99	0.3360	446.47	0.4465
IS	Iceland	0.13	0.0001	401.93	0.4019
IT	Italy	323.84	0.3238	458.57	0.4586
LT	Lithuania	253.56	0.2536	340.19	0.3402
LU	Luxembourg	101.36	0.1014	-	-
LV	Latvia	215.67	0.2157	421.52	0.4215
MT	Malta	390.62	0.3906	390.92	0.3909
NL	Netherlands	374.34	0.3743	451.72	0.4517
NO	Norway	7.62	0.0076	401.94	0.4019
PL	Poland	759.62	0.7596	798.68	0.7987
PT	Portugal	301.55	0.3016	375.38	0.3754
RO	Romania	261.84	0.2618	265.16	0.2652
RS	Serbia	776.69	0.7767	810.76	0.8108
ES	Spain	171.03	0.1710	286.53	0.2865
SE	Sweden	5.67	0.0057	23.14	0.0231
SI	Slovenia	224.05	0.2241	345.20	0.3452
SK	Slovakia	155.48	0.1555	218.23	0.2182
GB	United Kingdom	196.44	0.1964	316.00	0.3160

Footnote and Source:

[a] Association of Issuing Bodies (AIB). *European Residual Mixes 2020*. Version 1.0, 2021-05-31. May 2021. https://www.aib-net.org/sites/default/files/assets/facts/residual-mix/2020/AIB_2020_Residual_Mix_Results.pdf. Factors do not include emissions from transmission and distribution losses. Emission factors were converted from units of g/kW-hr to units of tonne/MW-hr.

[b] Table 5: Production Mix 2020.

[c] Table 2: Residual Mixes 2020.

8.1.4 Renewable Energy

Footnotes to Table 8-1 address some unique characteristics for electricity generated from renewable energy sources. Renewable energy sources that have no combustion-related emissions do not contribute to GHG emissions. Biogenic fuel[8] combustion sources are treated separately for GHG accounting purposes. Although a CO_2 emission factor is provided for wood waste biomass in Table 8-1, by GHG emission accounting convention, CO_2 emissions from combustion of biogenic fuels are reported separately from the other scopes[9]. Carbon dioxide emissions from biomass should be reported separately as biogenic CO_2 and not included in the Scope 2 CO_2 emissions from purchased fossil fuel generation. However, the combustion of biomass does result in net additions of CH_4 and N_2O to the atmosphere. These emissions should be accounted for in Scope 2 emissions from purchased biogenic generated energy.

Geothermal Energy

Geothermal energy is a renewable resource that utilizes heat and steam produced in the earth's core for heating and energy generation. The three primary uses of geothermal energy are: direct use and district heating systems, electricity generation, and geothermal heat pumps. GHG emissions do result from geothermal electricity generation; however, compared to other methods of generation, emissions from geothermal power plants are very low.

There are three basic types of geothermal power plants: dry steam plants, flash steam plants, and binary power plants. Dry and flash steam plants use the geothermal steam (or geothermal hot water converted to steam) to drive generator turbines. When the steam cools, it is converted to water and injected back into the ground to be used again. In both dry and flash steam plants, the gases contained in the geothermal streams do not condense at the turbine exhaust outlet and so are released to the atmosphere. Binary power plants use geothermal hot water to heat another liquid, which is then vaporized and used to drive the generator turbines. Binary plants do not expose the geothermal stream to the atmosphere, so the non-condensable gases contained in the geothermal streams are not released.

The emission factors provided in Table 8-1 for geothermal energy generation are taken from four separate sources. The International Geothermal Association conducted a survey to determine CO_2 emissions from geothermal power plants from around the world (Bertani and Thain, 2001). Emission data were collected from 85 geothermal power plants operating in 11 countries,

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[8] Biogenic carbon refers to carbon that was recently contained in living and breathing tissues (WRI/WBSCD GHG Protocol, Stationary Combustion Guidance, July 2005).

[9] IPCC, 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2:Energy, 2019. https://www.ipcc-nggip.iges.or.jp/public/2019rf/pdf/2_Volume2/19R_V2_2_Ch02_Stationary_Combustion.pdf.

representing 85% of the worldwide geothermal power plant capacity. Bloomfield and Moore (Bloomfield and Moore, 1999) conducted a survey of data from geothermal operators, utilities, and U.S. state air-quality boards. The primary sources of data were the operators of dry steam and flash plants, although the emission rate is for all geothermal plants (including binary power plants). The EIA emission factor is based on EIA estimates. The New Zealand CO_2e emission factor represents and weighted average by generation of the emissions intensity across all geothermal power plants nationwide for 2019 (McLean, et al, 2020).

8.1.5 Steam/Heat Utility Emissions

Imported steam/heat or steam/heat generated on site results in GHG emissions due to combustion that occurs to produce the steam. If the method of generation for the steam/heat is known, the approach to estimate combustion emissions given in Sections 4.3 through 4.5 can be used.

To estimate GHG emissions from imported steam or district heating, or where information about the steam/heat generator is unknown, a simple approach of assuming that the steam/heat was generated in a natural gas boiler is suggested. A thermal-based emission factor for this approach can be developed by dividing a boiler emission factor on a lower heating value (LHV) basis by an assumed boiler efficiency. For example, the LHV natural gas combustion emission factors given in Table 4-3 for CO_2 and Table 4-7 for CH_4 and N_2O (controlled) can be converted to a thermal basis by dividing by an assumed 92% boiler efficiency, as shown below. The assumed 92% boiler efficiency does not account for steam transport losses. The efficiency should be reduced to account for inefficiencies in transporting the steam for the specific application.

$$\begin{aligned}
\text{CO}_2\ \text{Emission Factor} &= \frac{5.90\times10^{-2}\ \text{tonne}/10^6\ \text{Btu}}{0.92}\\
&= 6.41\times10^{-2}\ \text{tonne CO}_2/10^6\ \text{Btu (steam/heat energy basis, LHV)}\\
&= \frac{6.41\times10^{-2}\ \text{tonne CO}_2}{10^6\ \text{Btu}}\times\frac{\text{Btu}}{1055.056\ \text{J}}\\
&= 6.08\times10^{-5}\ \text{tonne CO}_2/10^6\ \text{J (steam/heat energy basis, LHV)}
\end{aligned}$$

$$\begin{aligned}
\text{CH}_4\ \text{Emission Factor} &= \frac{1.1\times10^{-6}\ \text{tonne}/10^6\ \text{Btu}}{0.92}\\
&= 1.20\times10^{-6}\ \text{tonne CH}_4/10^6\ \text{Btu (steam/heat energy basis, LHV)}\\
&= \frac{1.20\times10^{-6}\ \text{tonne CH}_4}{10^6\ \text{Btu}}\times\frac{\text{Btu}}{1055.056\ \text{J}}\\
&= 1.14\times10^{-9}\ \text{tonne CH}_4/10^6\ \text{J (steam/heat energy basis, LHV)}
\end{aligned}$$

$$\begin{aligned}
\text{N}_2\text{O Emission Factor} &= \frac{3.0\times10^{-7}\ \text{tonne}/10^6\ \text{Btu}}{0.92}\\
&= 3.26\times10^{-7}\ \text{tonne N}_2\text{O}/10^6\ \text{Btu (steam/heat energy basis, LHV)}\\
&= \frac{3.26\times10^{-7}\ \text{tonne N}_2\text{O}}{10^6\ \text{Btu}}\times\frac{\text{Btu}}{1055.056\ \text{J}}\\
&= 3.09\times10^{-10}\ \text{tonne N}_2\text{O}/10^6\ \text{J (steam/heat energy basis, LHV)}
\end{aligned}$$

The quantity of steam consumed may be expressed in energy units or mass units. Where steam consumption is measured in mass units, the pressure and temperature of the steam are needed to convert to an equivalent energy basis. As demonstrated by Equation 8-1, the mass quantity of the steam is converted to an equivalent thermal energy basis by quantifying the difference in enthalpy at the temperature and pressure of the steam compared to a reference condition of saturated water at 212°F (100°C).

$$\text{Steam Thermal Equivalent} = \text{Mass steam}\times(\text{Enthalpy}_{\text{Actual}}-\text{Enthalpy}_{\text{Reference}}) \qquad \text{Equation 8-1}$$

The enthalpy of the steam at actual and reference conditions can be found in standard steam tables[10]. The steam factors given above can then be applied to determine the CO_2, CH_4, and N_2O indirect emissions from the imported steam.

Exhibit 8.3 illustrates this simplified approach.

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[10] https://www.engineeringtoolbox.com/saturated-steam-properties-d_273.html

EXHIBIT 8.3: Sample Calculation for Steam (Indirect) Emissions

INPUT DATA:
A facility purchases 15 million pounds of 600 psig, 700°F steam during a given year. The method of steam generation is unknown. Calculate the emissions.

CALCULATION METHODOLOGY:
Because the method of steam generation is unknown, the simple approach of assuming that the steam was generated in a natural gas boiler with an efficiency of 92% is used. The efficiency is reduced further by 10% to account for the steam transport losses. The first step is to convert the mass of steam generated into an equivalent thermal basis using 212°F saturated water as the reference basis. Using a commonly available steam thermodynamic table, the enthalpy of the steam at the two conditions are:

Steam, 600 psig, 700°F = 1350 Btu/lbm
Saturated Water, 212°F = 180 Btu/lbm

Thus, the equivalent steam thermal energy is:

$$\text{Steam thermal equivalent} = (15 \times 10^{6}\ \text{lbm/yr})\ (1350\ \text{Btu/lbm} - 180\ \text{Btu/lbm}) = 1.755 \times 10^{10}\ \text{Btu/yr}$$

The emissions are now estimated using the emission factors presented in the preceding discussion:

$$E_{CO_2} = \frac{1.755\times10^{10}\ \text{Btu}}{\text{yr}} \times \frac{5.90\times10^{-2}\ \text{tonne CO}_2}{10^{6}\ \text{Btu}} \times \frac{1}{(0.92-0.10)}$$

$$\underline{E_{CO_2} = 1{,}263\ \text{tonnes CO}_2/\text{yr}}$$

$$E_{CH_4} = \frac{1.755\times10^{10}\ \text{Btu}}{\text{yr}} \times \frac{1.10\times10^{-6}\ \text{tonne CH}_4}{10^{6}\ \text{Btu}} \times \frac{1}{(0.92-0.10)}$$

$$\underline{E_{CH_4} = 0.0235\ \text{tonnes CH}_4/\text{yr}}$$

$$E_{N_2O} = \frac{1.755\times10^{10}\ \text{Btu}}{\text{yr}} \times \frac{3.0\times10^{-7}\ \text{tonne N}_2\text{O}}{10^{6}\ \text{Btu}} \times \frac{1}{(0.92-0.10)}$$

$$\underline{E_{N_2O} = 0.0064\ \text{tonnes N}_2\text{O/yr}}$$

8.1.6 District Cooling Water Emissions

Similar to purchased heat or steam, facilities may also purchase cooling water or chilled water. Chilled water is typically generated by pressurizing a gaseous substance with a compressor and then allowing the substance to return to standard pressure. When the pressure is released from the gas, it absorbs thermal energy as it expands, lowering the temperature. The compressor system that produces the cooling water may be driven by electricity or fossil fuel combustion. Thus, the estimate of indirect emissions is similar to that of purchased heat or steam. Indirect emissions from district cooling for a given facility represent the share of the total cooling demand from the cooling plant to the facility, multiplied by the total GHG emissions generated by the cooling plant. The quantity of cooling water may be expressed in energy units (Btu or J), or in units of mass-hours (e.g. ton-hours, where 1 ton-hour = 12,000 BTUs). Equation 8-2 is used to determine the energy input resulting from a facility's cooling demand.

$$\text{Energy Input (MMBtu or J)} = \frac{\text{Cooling Demand (MMBtu or J)}}{\text{COP}}$$

Equation 8-2

where

COP = Coefficient of Performance, which is defined as the ratio of cooling demand to energy input for the cooling plant, based on the type of chiller.

If the COP for the cooling plant is known, it should be used in Equation 8-2. If unknown, the COP for common types of chillers is provided in Table 8-7.

Table 8-7. Typical Chiller Coefficients of Performance

Equipment Type	Coefficient of Performance (COP) [a]	Energy Source
Absorption Chiller	0.8	Natural Gas
Engine-driven Compressors	1.2	Natural Gas
Electric-driven Compressor	4.2	Electricity

Footnote and Source:
[a] California Climate Action Registry (CCAR). *California Climate Action Registry General Reporting Protocol: Reporting Entity-Wide Greenhouse Gas Emissions*, Version 3.1, January 2009.

For cooling plants that use absorption chillers or natural gas-driven compressors, emissions are estimated based on the energy input determined from Equation 8-2 and the natural gas combustion emission factor from Table 4-3. For cooling plants that use electric-driven compression, the energy input from Equation 8-2 must be converted to megawatt – hour (MW-hr) (1 MW-hr = 3.4121 10^6BTU from Table 3-4) to apply the emission factors presented in Sections 8.1.1 through 8.1.3.

8.2 Allocation of Emissions Among Energy Streams

In ongoing efforts to improve energy efficiency, many operations co-produce energy streams or utilize excess process heat for energy generation. Processes that simultaneously produce energy streams used by two or more different parties present a special case for estimating GHG emissions. This includes the cogeneration of electricity and heat/steam, as well as operations that produce heat (steam) and other product streams (hydrogen or coke). For these processes, attributing total GHG emissions to each product stream would result in double counting emissions.

The general process for estimating emissions from co-produced streams is:

1. Obtain the total GHG emissions associated with the generation of all energy and product streams;
2. Determine emissions or emission factors attributable to net energy and product stream energy content using one of the methods discussed below;
3. Calculate GHG emissions (CO_2, CH_4, and N_2O) associated with your entity's portion of the energy or product streams; and
4. Convert to units of CO_2 equivalent emissions.

Data required for the allocation approaches presented in this section include the quantity of fuel consumed, quantity of energy streams generated and sold, electricity generated and sold, energy content of product streams generated and sold, and for the WRI/WBCSD efficiency allocation approach, the efficiencies of heat and power production (although default efficiencies may also be used).

8.2.1 Cogeneration of Electricity and Steam

Cogeneration of electricity and steam, also known as CHP, is the simultaneous production of electricity and process heat from the same fuel. In these units, the heat produced from the electricity generating process (e.g., from the exhaust systems of gas turbines or from conventional boilers with steam turbines) is captured and used for process steam, hot water heating, space heating, and other thermal needs, or to produce additional electricity. Lower emissions result from these processes because process heat is generated with little or no additional fuel usage. Note that for some processes, additional energy from a secondary combustion unit is required to generate steam. GHG emissions should also be considered from this supplemental combustion source.

Where electricity and/or steam/heat produced from the cogeneration facility is transferred, sold, or otherwise used by two or more entities, GHG accounting may require allocating the emissions resulting from the CHP among the energy streams. Several registries and GHG reporting programs; have published approaches for allocating emissions between energy streams in cases where these streams are used by two or more different parties (CCAR, 2009; Defra, 2008b; DOE, 2007; TCR, 2019; and WRI/WBCSD, 2006). The three most common methods are:

1. *Efficiency method:* GHG emissions are allocated based on the energy input used to produce the separate steam and electricity products;
2. *Energy content method:* GHG emissions are allocated based on the energy content of the output steam and electricity products; and
3. *Work potential method:* GHG emissions are allocated based on the contribution to the total work potential of the steam and electricity products.

These approaches apply to emissions associated with the direct import/export of electricity from a CHP facility. Each approach partitions the total emissions resulting from fuel combustion in the cogeneration unit between the electricity and steam energy streams. As a result, the sum of the emissions assigned to the individual energy streams is equivalent to the total emissions resulting from the fuel combusted to produce the energy. These allocation methodologies are discussed further and illustrated through calculation exhibits.

GHG emissions from cogeneration plants could also be allocated based on:

- The economic value of the steam and electricity products;
- Allocating 100% of GHG emissions to electricity production (steam production is emissions free);
- Allocating 100% of GHG emissions to steam production (electricity production is emissions free);
- Allocating savings to electricity production (electricity emissions equal total emissions less emissions from conventional steam production, and steam emissions equal emissions of conventional steam production);
- Allocating savings to steam production (steam emissions equal total emissions less emissions from conventional electricity production, and electricity emissions equal emissions of conventional electricity production); or
- Allocating emissions according to a contractual agreement or other understanding between the parties.

Efficiency Allocation Method

The efficiency method allocates GHG emissions according to the amount of fuel energy used to produce each output energy stream. Allocation is based on the assumption that the conversion of fuel energy to steam is more efficient than converting fuel to electricity.

To apply the efficiency allocation method, the first step is to calculate the total direct CO_2 emissions from the combustion of fuel (generally natural gas) at the cogeneration facility. The combustion emissions are estimated using methods presented in Section 4.

The second step is to calculate the thermal equivalent of the steam. The mass of steam generated is converted to an equivalent thermal basis using 212°F saturated water as the reference basis. A commonly available steam table provides the enthalpy of the steam at the actual and reference conditions.

The third step is to allocate the total emissions to the electricity and steam streams. Two allocation methods are presented: one from the WRI/WBCSD and a second from the UK Emissions Trading Scheme (ETS).

The allocation approach referenced in the WRI/WBCSD GHG Protocol (WRI/WBCSD, 2006), relies on actual efficiencies of heat and power production or assumed values, if actual values are unknown. The equations associated with the WRI/WBCSD efficiency allocation approach are:

$$\text{Emissions}_{\text{Heat}} = \text{Emissions}_{\text{Total}} \times \frac{\dfrac{\text{Heat Output}}{\text{Efficiency}_{\text{Heat}}}}{\dfrac{\text{Heat Output}}{\text{Efficiency}_{\text{Heat}}} + \dfrac{\text{Electricity Output}}{\text{Efficiency}_{\text{Electricity}}}} \qquad \text{(Equation 8-3)}$$

and

$$\text{Emissions}_{\text{Total}} = \text{Emissions}_{\text{Heat}} + \text{Emissions}_{\text{Electricity}} \qquad \text{(Equation 8-4)}$$

where

$\text{Emissions}_{\text{Total}}$ = total emissions from CHP plant;
$\text{Emissions}_{\text{Heat}}$ = emissions share attributable to heat production;
$\text{Emissions}_{\text{Electricity}}$ = emissions share attributable to electricity production;
$\text{Efficiency}_{\text{Heat}}$ = actual or assumed efficiency of typical heat production; and
$\text{Efficiency}_{\text{Electricity}}$ = actual or assumed efficiency of typical power production.

Heat output and electricity output are reported in the same units (Joule, Btu or kilowatt-hr). Where actual efficiencies are not available, EPA's Climate Leaders reporting guidelines provide default values for U.S. operations of 35% efficiency for electricity production and 80% efficiency for heat production (EPA, 2008). These same default efficiencies are used in the WRI/WBCSD tool for emissions allocations between heat and electricity.[11] It should be noted that the use of default efficiency values may violate the energy balance constraints of some cogeneration systems. However, the impact on the emission estimates should be minimal since the total emissions are still allocated between the energy outputs.

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[11] World Business Council for Sustainable Development (WRI/WBCSD). Calculation Tools. *Allocation of GHG Emissions from a Combined Heat and Power (CHP) Plant:* Worksheet, September, 2006. https://ghgprotocol.org/calculation-tools, accessed September 10, 2021.

EXHIBIT 8.4: Cogeneration Emissions Allocation – WRI/WBCSD Efficiency Allocation Method

INPUT DATA:
A cogeneration facility operates three natural gas-fired combustion turbines, three heat recovery steam generators with supplemental duct firing capability, and a steam turbine.

The cogeneration facility consumes 8,131,500 million Btu of natural gas, producing 3,614,000 million Btu steam and 1,100,600 megawatt-hr of electricity (gross) on an annual basis. A nearby refinery purchases 2,710,000 million Btu of steam and 206,000 megawatt-hr of electricity. The cogeneration facility also consumes 38,500 megawatt-hr of electricity to operate (referred to as the Parasitic load). The net electricity (856,100 megawatt-hrs, metered at the custody transfer point) is sold to the electric grid.

For this example, the known efficiency of steam generation is 80% and the efficiency of the electricity generation is 33%.

Using the WRI/WBCSD Efficiency Allocation Approach, calculate the cogeneration facility emissions, refinery emissions, and emissions associated with electricity sold to the grid.

CALCULATION METHODOLOGY:
<u>Step 1: Combustion Emissions from Cogeneration</u>:
For the cogeneration unit, emissions are calculated based on the natural gas consumed using the emission factors in Table 4-3 for CO_2 and Table 4-7 (natural gas turbines) for CH_4 and N_2O:

$$E_{CO_2} = 8{,}131{,}500 \times 10^6 \text{ Btu} \times \frac{0.0531 \text{ tonnes } CO_2}{10^6 \text{ Btu natural gas}}$$

$$\underline{E_{CO_2} = 431{,}783 \text{ tonnes } CO_2}$$

$$E_{CO_2e} = 431{,}783 + \left(31.7 \times \frac{21 \text{ tonnes } CO_2e}{\text{tonnes } CH_4}\right) + \left(11.4 \times \frac{310 \text{ tonnes } CO_2e}{\text{tonnes } N_2O}\right)$$

$$\underline{E_{CO_2e} = 435{,}983 \text{ tonnes } CO_2e \text{ (Direct, Cogen)}}$$

EXHIBIT 8.4: Cogeneration Emissions Allocation – WRI/WBCSD Efficiency Allocation Method, continued

Step 2: Define Power and Heat Production on the Same Units

The electric power output (P) from the cogeneration unit needs to be converted from a megawatt-hr basis to Btu. The conversion factor is provided in Table 3-4.

$$\text{P} = 1{,}100{,}600 \text{ megawatt-hr} \times \frac{1000 \text{ kilowatt-hr}}{\text{megawatt-hr}} \times \frac{\text{Btu}}{2.931 \times 10^{-4} \text{ kilowatt-hr}}$$

$$\text{P} = 3.755 \times 10^{12} \text{ Btu (Electricity Output)}$$

Step 3: Calculate the Emissions Allocated to Steam

Estimate the emissions associated with the steam generation by applying Equation 7-5.

$$\text{E}_{\text{Heat}} = 435{,}983 \text{ tonnes CO}_2\text{e} \times \frac{\dfrac{3{,}614{,}000 \times 10^6 \text{ Btu}}{0.80}}{\dfrac{3{,}614{,}000 \times 10^6 \text{ Btu}}{0.80} + \dfrac{3.755 \times 10^{12} \text{ Btu}}{0.33}}$$

$$\text{E}_{\text{Heat}} = 435{,}983 \text{ tonnes CO}_2\text{e} \times 0.284186$$

$$\text{E}_{\text{Heat}} = 123{,}900.2 \text{ tonnes CO}_2\text{e}$$

Step 4: Calculate the Emissions Allocated to Electricity

Applying Equation 7-6, the emissions allocated to electricity are calculated based on the difference between the total emissions and those allocated to steam.

$\text{E}_{\text{Electricity}}$ = 435,983 tonnes CO_2e (Total) – 123,900.2 tonnes CO_2e (Heat)

$\text{E}_{\text{Electricity}}$ = 312,092.8 tonnes CO_2e (Electricity)

Step 5: Allocate Emissions for Energy Exports

The total steam and electricity emissions can be estimated for exports based on the ratio of the total electricity and steam generated versus the energy sold.

EXHIBIT 8.4: Cogeneration Emissions Allocation – WRI/WBCSD Efficiency Allocation Method, continued

CO_2 Equivalent Emissions for electricity sold to the refinery ($E_{Elec,\ ref}$):

$$E_{\text{Elec, ref}} = 312{,}082.8 \text{ tonnes } CO_2\text{e (Total Electricity)} \times \frac{206{,}000 \text{ megawatt-hr (Refinery)}}{1{,}100{,}600 \text{ megawatt-hr (Total)}}$$

$$E_{\text{Elec, ref}} = 58{,}412.7 \text{ tonnes } CO_2\text{e (Direct, Cogen; Indirect, Refinery)}$$

CO_2 Equivalent Emissions for electricity sold to the grid ($E_{Elec,\ grid}$):

$E_{Elec,\ grid}$ =312,082.8 tonnes CO_2e (Total Electricity) – 58,412.7 tonnes CO_2e (Refinery)

$E_{Elec,\ grid}$ = 253,670.1 tonnes CO_2e (Direct, Cogen; Indirect, Grid Consumer)CO_2 Equivalent Emissions for steam sold to the refinery ($E_{Steam,\ ref}$):

$$E_{\text{Steam, ref}} = 123{,}900.2 \text{ tonnes } CO_2\text{e (Total Heat)} \times \frac{2{,}710{,}000 \times 10^6 \text{ Btu (Refinery)}}{3{,}614{,}000 \times 10^6 \text{ Btu (Total)}}$$

$$E_{\text{Steam, ref}} = 92{,}908 \text{ tonnes } CO_2\text{e (Direct, Cogen; Indirect, Refinery)}$$

Step 6: Calculate Net Cogeneration Facility Emissions

Net cogeneration facility emissions are calculated by subtracting emissions from steam and electricity sold to the refinery and electricity sold to the grid from the total emissions calculated in Step 1.

Net Cogeneration Facility CO_2 Emissions (E_{Net}):

$$E_{\text{Net}} = 435{,}983 \text{ tonnes } CO_2\text{e} - \left(58{,}412.7 + 253{,}670.1 + 92{,}908 \text{ tonnes } CO_2\text{e}\right)$$

$$E_{\text{Net}} = 30{,}992.2 \text{ tonnes } CO_2\text{e (Direct, Cogen)}$$

The results for the allocation of emissions based on energy efficiency are shown in the table below.

EXHIBIT 8.4: Cogeneration Emissions Allocation – WRI/WBCSD Efficiency Allocation Method, continued

Summary of Cogeneration Emissions – WRI/WBCSD Efficiency Allocation Method

	Emissions, tonnes CO_2e	
Cogeneration Facility (Direct, Cogen)		
Direct Emissions from Fuel Consumption	435,983	
Emissions Associated with Electricity Sold to the Grid (Direct, Cogen, and Indirect, Grid Consumer)	253,670	Sums to 435,983
Net Facility Emissions	30,992	
Refinery Emissions (Direct, Cogen; Indirect, Refinery)		
Purchased electricity	58,413	
Purchased Steam	92,908	

This efficiency allocation approach using Equations 8-3 and 8-4 is demonstrated in Exhibit 8.4. Note that this approach is preferred by WRI/WBCSD GHG Protocol (WRI, 2006), EPA's Climate Leaders Program (EPA, 2008), The Climate Registry (TCR, 2019), DOE's 1605(b) program (DOE, 2007), and California's Air Resources Board (CARB, 2008) for Topping Cycle Plants[12].

The UK ETS allocation approach is based on the assumption that the efficiency of heat generation is twice that of electricity generation (Defra, 2012). The equations are provided below.

Electricity Emission Factor from Cogeneration Facility:

$$\begin{array}{c}\text{CO}_2\ \text{EF from electricity}\\ (\text{tonnes CO}_2/\text{megawatt-hr})\end{array} = \frac{2 \times \text{CO}_2\ \text{direct emissions (tonnes CO}_2)}{\left[2 \times \text{Electricity produced (megawatt-hr)}\right] + \text{Steam produced (megawatt-hr)}}$$

(Equation 8-5)

Steam Emission Factor from Cogeneration Facility:

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[12] Note that Topping Cycle Plants, which generate electricity at the start of the cycle and use the resulting heat or steam for a process stream, are different than Bottoming Cycle Plants, which use steam or heat from a process stream to generate electricity at the end of the cycle.

$$\begin{array}{c}\text{CO}_2\ \text{EF from steam}\\ (\text{tonnes CO}_2/\text{megawatt-hr})\end{array} = \frac{\text{CO}_2\ \text{direct emissions (tonnes CO}_2)}{\left[2 \times \text{Electricity produced (megawatt-hr)}\right] + \text{Steam produced (megawatt-hr)}}$$

(Equation 8-6)

This approach is illustrated in the Exhibit 8.5.

Energy Content Method

The energy content method allocates emissions based on the amount of useful energy contained in each energy output stream. The energy content of the electrical power is simply the amount of electricity produced by the system (converted to units of Btu or Joules). The energy content of the steam (or hot water) is equivalent to the energy content of the output stream less any energy in the returned condensate. Losses due to inefficient use of either the electricity or steam outputs are not considered. This allocation method is particularly well suited for applications where steam is used for process heat, but may not be appropriate where heat is used for mechanical work because it may overstate the amount of useful energy in the heat, resulting in a low emission factor associated with the heat stream.

This approach starts with obtaining the total fuel consumption emissions associated with generating the heat and steam. For electricity, the energy content is equal to the energy output, converted to units consistent with the steam energy (Btu or Joules). The energy content of the steam is calculated by applying Equation 8-1.

For steam, only the fraction of the total energy in the steam (or hot water) that can be used for process heating is considered. It is also assumed that the steam is used for indirect heating, with condensates returned to the CHP system. If the condensates are not returned or if a hot water output stream is considered in the allocation, different reference conditions than shown below should be applied (e.g., the temperature and pressure of boiler feed water).

EXHIBIT 8.5: Cogeneration Emissions Allocation – UK ETS Efficiency Allocation Method

INPUT DATA:
For the same scenario as described in the previous exhibit (Exhibit 7.4), this example applies the UK ETS Efficiency Allocation approach.

The cogeneration facility consumes 8,131,500 million Btu of natural gas, producing 3,614,000 million Btu steam and 1,100,600 megawatt-hr of electricity (gross) on an annual basis. A nearby refinery purchases 2,710,000 million Btu of steam and 206,000 megawatt-hr of electricity. The cogeneration facility also consumes 38,500 megawatt-hr of electricity to operate (referred to as the Parasitic load). The net electricity (856,100 megawatt-hrs, metered at the custody transfer point) is sold to the electric grid.

Using the UK ETS Efficiency Allocation Method, calculate the cogeneration facility emissions, refinery emissions, and emissions associated with electricity sold to the grid.

CALCULATION METHODOLOGY:
This example applies the UK Emissions Trading System approach to allocating emissions between steam and electricity. Note that the UK ETS program does not currently address CH_4 and N_2O emissions, but the approach presumably applies to CO_2 equivalent emissions.

Step 1: Combustion Emissions from Cogeneration:
The total direct emissions are calculated as shown in Exhibit 8.4, resulting in 435,983 tonnes CO_2e emissions (Direct, Cogen).

Step 2: Steam Thermal Equivalent
The total amount of steam generated from the cogeneration facility needs to be converted from a Btu basis to a megawatt-hr basis. The conversion factor is provided in Table 3-2.

The steam thermal equivalent ($S_{Eq.}$) is calculated below:

$$S_{Eq} = 3{,}614{,}000 \times 10^6 \text{ Btu steam} \times \frac{2.931 \times 10^{-4} \text{ kilowatt-hr}}{\text{Btu}} \times \frac{\text{meagwatt-hr}}{1000 \text{ kilowatt-hr}}$$

$$S_{Eq} = 1{,}059{,}263 \text{ megawatt-hr/yr}$$

EXHIBIT 8.5: Cogeneration Emissions Allocation – UK ETS Efficiency Allocation Method, continued

Step 3: Calculate Electricity and Steam Emission Factors

The third step is to apply the UK ETS equations (Equations 8-5 and 8-6) for allocating emissions between the electricity and steam energy to generate emission factors.

Electricity allocation ($E_{Electricity}$):

$$E_{Electricity} = \frac{2 \times 435{,}982 \text{ tonnes } CO_2e}{\left[2 \times 1{,}100{,}600 \text{ megawatt} - \text{hr}_{Electricity}\right] + 1{,}059{,}263 \text{ megawatt-hr}_{Steam}}$$

$$E_{Electricity} = 0.267 \text{ tonnes } CO_2e \text{ /megawatt-hr}$$

Steam allocation (E_{Steam}):

$$E_{Steam} = \frac{435{,}983 \text{ tonnes } CO_2e}{\left[2 \times 1{,}100{,}600 \text{ megawatt} - \text{hr}_{Electricity}\right] + 1{,}059{,}263 \text{ megawatt-hr}_{Steam}}$$

$$E_{Steam} = 0.134 \text{ tonnes } CO_2e \text{ /megawatt-hr}$$

Step 4: Allocate Emissions to Electricity and Steam

Emissions are allocated between electricity and steam used for energy on site (direct emissions) and the exported electricity and steam (indirect emissions) by applying the emission factors calculated in Step 3.

CO_2 Equivalent emissions for electricity sold to the refinery ($E_{Elec, refinery}$):

$$E_{Elec,\ refinery} = \frac{0.267 \text{ tonnes } CO_2}{\text{megawatt-hr electricity}} \times 206{,}000 \text{ megawatt-hr}$$

$$E_{Elec,\ refinery} = 55{,}002 \text{ tonnes } CO_2e \text{ (Direct, Cogen; Indirect, Refinery)}$$

CO_2 Equivalent emissions for electricity sold to the grid ($E_{Elec, grid}$):

$$E_{Elec,\ grid} = \frac{0.267 \text{ tonnes } CO_2}{\text{megawatt-hr electricity}} \times 856{,}100 \text{ megawatt-hr}$$

$$E_{Elec,\ grid} = 228{,}579 \text{ tonnes } CO_2e \text{ (Direct, Cogen; Indirect, Grid Consumer)}$$

EXHIBIT 8.5: Cogeneration Emissions Allocation – UK ETS Efficiency Allocation Method, continued

CO_2 Equivalent emissions for steam sold to the refinery ($E_{Steam, ref}$):

$$E_{\text{Steam, Ref}} = 2{,}710{,}000 \times 10^{6}\ \text{Btu steam} \times \frac{2.931 \times 10^{-4}\ \text{kW-hr}}{\text{Btu}} \times \frac{\text{MW-hr}}{1000\ \text{kW-hr}} \times \frac{0.134\ \text{tonnes CO}_2}{\text{MW-hr steam}}$$

$$E_{\text{Steam, ref}} = 106{,}436\ \text{tonnes CO}_2\text{e (Direct, Cogen; Indirect, Refinery)}$$

Step 5: Calculate Net Cogeneration Facility Emissions

Net cogeneration facility emissions are calculated by subtracting emissions from steam and electricity sold to the refinery and electricity sold to the grid from the total emissions calculated in Step 1.

Net Cogeneration Facility CO_2 Emissions (E_{Net}):

$$E_{\text{Net}} = 435{,}983\ \text{tonnes CO}_2\text{e} - \left(55{,}002 + 228{,}579 + 106{,}436\right)\text{tonnes CO}_2\text{e}$$

$$E_{\text{Net}} = 45{,}966\ \text{tonnes CO}_2\text{e (Direct, Cogen)}$$

Accounting for round-off error, the sum of the emissions assigned to onsite and offsite steam and electricity should equal the total direct emissions from combustion. This is summarized in the table below.

Summary of Cogeneration Emissions – UK ETS Efficiency Allocation Method

	Emissions, tonnes CO_2e	
Cogeneration Facility (Direct, Cogen)		
Direct Emissions from Fuel Consumption	435,983	
Emissions Associated with Electricity Sold to the Grid (Direct, Cogen, and Indirect, Grid Consumer)	228,579	Sums to 435,938
Net Facility Emissions	45,966	
Refinery Emissions (Direct, Cogen; Indirect, Refinery)		
Purchased electricity	55,002	
Purchased Steam	106,436	

The values of enthalpy at the actual and reference conditions can be found in standard steam tables. The reference conditions of 212°F (100°C) and 1 atm (101.325 kilo-Pascals) correspond to condensates returned to the CHP.

The emissions allocated to the individual energy streams are then calculated as:

$$\text{Emissions}_{\text{Heat/Steam}} = \text{Emissions}_{\text{Total}} \times \frac{\text{Energy}_{\text{Heat/Steam}}}{\text{Energy}_{\text{Heat/Steam}} + \text{Energy}_{\text{Electricity}}} \qquad \text{(Equation 8-7)}$$

$$\text{Emissions}_{\text{Electricity}} = \text{Emissions}_{\text{Total}} \times \frac{\text{Energy}_{\text{Electricity}}}{\text{Energy}_{\text{Heat/Steam}} + \text{Energy}_{\text{Electricity}}} \qquad \text{(Equation 8-8)}$$

An example is provided in Exhibit 8.6. The basis for this calculation method was originally from Annex E of the National Council for Air and Stream Improvement (NCASI) report *Calculation Tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills* (November 2002). This approach has since been included in WRI/WBCSD's *Allocation of GHG Emissions from a Combined Heat and Power (CHP) Plant*, Guide to Calculation Worksheets, v1.0 (September, 2006).

Work Potential Allocation Method

This method allocates emissions based on the useful energy represented by the electric power and heat, and defines useful energy on the ability of heat to perform work. This method assumes that the useful energy in steam corresponds to the maximum amount of work that could be done by the steam in an open (flow) steady state and thermodynamically reversible process. This method is most appropriate when heat is to be used for producing mechanical work.

In applications where steam is used for process heat, the useful energy in the steam corresponds to the heat content of the steam, or its enthalpy. As a result, the work potential method would underestimate the amount of useful energy in the steam and should not be used.

The work potential for steam is calculated from the specific enthalpy (H) and specific entropy (S) of the steam. This approach sums the work potential of all streams and allocates the total emissions to the individual streams.

As with the other allocation methods, the first step is to calculate the total direct emissions from the combustion of natural gas at the cogeneration facility. The second step is to calculate the work potential of the steam, using 212°F (100°C) saturated water as the reference basis. The enthalpy and entropy of the steam can be determined from a steam table at the reference and actual conditions.

EXHIBIT 8.6: Cogeneration Emissions Allocation – WRI/WBCSD Energy Content Method

INPUT DATA:
For the same scenario as described in the previous exhibit, this example applies the energy content approach.

The cogeneration facility consumes 8,131,500 million Btu of natural gas, producing 3,089 million pounds of 600 psig and 700 °F steam and 1,100,600 megawatt-hr of electricity (gross) on an annual basis. The refinery purchases 2,710,000 million Btu of steam and 206,000 megawatt-hr of electricity. The cogeneration facility also consumes 38,500 megawatt-hr of electricity to operate (referred to as the Parasitic load), with the net electricity (856,100 megawatts) sold to the electric grid.

Using the Energy Content Method, calculate the cogeneration facility emissions, refinery emissions, and emissions associated with electricity sold to the grid.

CALCULATION METHODOLOGY:

Step 1: Combustion Emissions from Cogeneration:
The total direct emissions are calculated as shown in Exhibit 8.4, resulting in 435,983 tonnes CO_2e emissions (Direct, Cogen).

Step 2: Calculate the Energy Associated with the Electricity

The electric power output (P) from the cogeneration unit needs to be converted from a megawatt-hr basis to Btu. The conversion factor is provided in Table 3-2.

$$\text{P} = 1{,}100{,}600 \text{ megawatt-hr} \times \frac{1000 \text{ kilowatt-hr}}{\text{megawatt-hr}} \times \frac{\text{Btu}}{2.931 \times 10^{-4} \text{ kilowatt-hr}}$$

$$\text{P} = 3.755 \times 10^{12} \text{ Btu (Electricity Output)}$$

Step 3: Calculate the Energy Associated with the Steam

Estimate the emissions associated with the steam generation by applying Equation 8-1.

EXHIBIT 8.6: Cogeneration Emissions Allocation – WRI/WBCSD Energy Content Method, continued

$$\text{Energy}_{\text{Steam}} = (3{,}089 \times 10^{6}\ \text{lbm/yr})\ (1350\ \text{Btu/lbm-180 Btu/lbm})$$

$$\text{Energy}_{\text{Steam}} = 3.614 \times 10^{12}\ \text{Btu/yr}$$

Step 4: Calculate the Emissions Allocated to Electricity
The emissions allocated to electricity are calculated based on Equation 8-8.

$$E_{\text{Elec}} = 435{,}983\ \text{tonnes CO}_2\text{e} \times \frac{3.755 \times 10^{12}\ \text{Btu}_{\text{Electricity}}}{3.614 \times 10^{12}\ \text{Btu}_{\text{Steam}} + 3.755 \times 10^{12}\ \text{Btu}_{\text{Electricity}}}$$

E_{Elec} = 222,163 tonnes CO_2e

Step 5: Allocate Emissions for Energy Exports
The total steam and electricity emissions can be divided among onsite and offsite usage based on the ratio of electricity and steam used on site versus the energy sold for use off site.

CO_2 Equivalent Emissions for electricity sold to the refinery ($E_{Elec,\ ref}$):

$$E_{\text{Elec, ref}} = 222{,}163\ \text{tonnes CO}_2\text{e (Total Electricity)} \times \frac{206{,}000\ \text{megawatt-hr (Refinery)}}{1{,}100{,}600\ \text{megawatt-hr Total}}$$

$E_{\text{Elec, ref}}$ = 41,582 tonnes CO_2e (Direct, Cogen; Indirect, Refinery)

CO_2 Equivalent Emissions for electricity sold to the grid ($E_{Elec,\ grid}$):

$E_{\text{Elec, grid}}$ = 222,163 tonnes CO_2e (Total Electricity) – 41,582 tonnes CO_2e (Refinery)

$E_{\text{Elec, grid}}$ = 180,581 tonnes CO_2e (Direct, Cogen; Indirect, Grid Consumer)

CO_2 Equivalent Emissions for steam sold to the refinery ($E_{Steam\ ,ref}$):

E_{Steam} = 435,983 tonnes CO_2e (Total)-222,163 tonnes CO_2e (Electricity)

E_{Steam} = 213,980 tonnes CO_2e (Direct, Cogen)

$$E_{\text{Steam,ref}} = 213{,}820\ \text{tonnes CO}_2\text{e (Total Steam)} \times \frac{2{,}710{,}000 \times 10^{6}\ \text{Btu (Refinery)}}{3{,}614{,}000 \times 10^{6}\ \text{Btu Total}}$$

$E_{\text{Steam,ref}}$ = 160,335 tonnes CO_2e (Direct, Cogen; Indirect, Refinery)

EXHIBIT 8.6: Cogeneration Emissions Allocation – WRI/WBCSD Energy Content Method, continued

Step 6: Calculate Net Cogeneration Facility Emissions

Net cogeneration facility emissions are calculated by subtracting emissions from steam and electricity sold to the refinery and electricity sold to the grid from the total emissions calculated in Step 1.

Net Cogeneration Facility CO_2 Emissions (E_{Net}):

$$E_{Net} = 435{,}983 \text{ tonnes } CO_2e - \left(41{,}582 + 180{,}581 + 160{,}335 \text{ tonnes } CO_2e\right)$$

$$E_{Net} = 53{,}485 \text{ tonnes } CO_2e \text{ (Direct, Cogen)}$$

The results for the allocation of emissions based on energy efficiency are shown in the table below.

Summary of Cogeneration Emissions – Energy Content Approach

	Emissions, tonnes CO_2e	
Cogeneration Facility (Direct, Cogen)		
Direct Emissions from Fuel Consumption	435,983	
Emissions Associated with Electricity Sold to the Grid (Direct, Cogen, and Indirect, Grid Consumer)	180,581	Sums to 435,983
Net Facility Emissions	53,485	
Refinery Emissions (Direct, Cogen; Indirect, Refinery)		
Purchased electricity	41,582	
Purchased Steam	160,335	

The work potential of the steam is calculated using the following equations.

In U.S. units:

$$\text{Steam work potential (Btu/lb)} = (H_i - H_{ref}) - (T_{ref} + 460) \times (S_i - S_{ref}) \qquad \text{(Equation 8-9)}$$

In SI units:

$$\text{Steam work potential } (10^9 \text{ J/tonne}) = (H_i - H_{ref}) - (T_{ref} + 273) \times (S_i - S_{ref}) \qquad \text{(Equation 8-10)}$$

where

H_i = specific enthalpy of the process steam (Btu/lb or 10^3 J/kilogram);
H_{ref} = specific enthalpy at the reference conditions (BTU/lb or 10^3 J/kilogram);
T_{ref} = reference temperature (°F or °C);
S_i = specific entropy of the process steam (Btu/lb R or 10^3 J/kilogram K); and
S_{ref} = specific entropy at the reference conditions (Btu/lb R or 10^3 J/kilogram K).

The third step is to allocate the total emissions from the cogeneration facility in proportion to their work potential, as shown in Equation 8-11.

$$\text{CO}_2 \text{ EF from electricity or steam (tonnes CO}_2\text{/megawatt-hr)} = \frac{\text{CO}_2 \text{ direct emissions (tonnes CO}_2\text{/yr)}}{\left[\text{Work potential}_{\text{steam}}\left(\frac{\text{megawatt-hr}}{\text{yr}}\right) + \text{Work potential}_{\text{electricity}}\left(\frac{\text{megawatt-hr}}{\text{yr}}\right)\right]} \qquad \text{(Equation 8-11)}$$

This allocation approach is demonstrated in Exhibit 8.7. This approach is referenced by WRI/WBCSD (WRI/WBCSD, 2006).

EXHIBIT 8.7: Cogeneration Emissions Allocation –Work Potential Allocation Method

This example applies the Work Potential Allocation method to allocating emissions between steam and electricity for the same facility described in Exhibit 8.4.

The cogeneration facility consumes 8,131,500 million Btu of natural gas, producing 3,614,000 million Btu steam at 700°F and 600 psia, and 1,100,600 megawatt-hr of electricity (gross) on an annual basis. The refinery purchases 2,710,000 million Btu of steam and 206,000 MW-hr of electricity. The cogeneration facility also consumes 38,500 megawatt-hr of electricity to operate (referred to as the Parasitic load), with the net electricity (856,100 megawatt-hrs) sold to the electric grid.

Using the Work Potential Allocation method, calculate the cogeneration facility emissions, refinery emissions, and emissions associated with electricity sold to the grid.

CALCULATION METHODOLOGY:

Step 1: Combustion Emissions from Cogeneration:
Direct emissions are calculated as shown in Exhibit 8.4, resulting in 435,983 tonnes CO_2e emissions (Direct, Cogen).

Step 2: Steam Work Potential

Steam work potential requires the enthalpy and entropy of the steam at both actual and reference conditions. These values can be determined using a steam table.

Enthalpy: Steam, 600 psia, 700°F = 1,350 Btu/lb (H_i);
Saturated Water, 212°F = 180 Btu/lb (H_{ref})

Entropy: Steam, 600 psia, 700°F = 1.5872 Btu/lb-R (S_i);
Saturated Water, 212°F = 0.31213 Btu/lb-R (S_{ref})

The work potential of the steam (SWP) is calculated using these values and Equation 8-9:

$$\text{SWP} = (1{,}350\text{-}180)\frac{\text{Btu}}{\text{lb}} - \left[\left(212+460\right)\text{R}\times\left(1.5872\text{-}0.31213\right)\frac{\text{Btu}}{\text{lb-R}}\right]$$

$$\text{SWP} = 313.2 \text{ Btu/lb}$$

In addition, the steam needs to be expressed on a mass basis (M_S) to apply the work potential equations.

$$M_S = 3{,}614{,}000\times10^6 \text{ Btu steam}\times\left(\frac{\text{lb steam}}{1{,}350 \text{ Btu}_{\text{steam conditions}}\text{-}180 \text{ Btu}_{\text{reference conditions}}}\right)$$

$$M_S = 3.089\times10^9 \text{ lbs steam}$$

Next, the mass of steam and the steam work potential are combined and converted to megawatt-hrs:

$$S = 3.089\times10^9 \text{ lbs steam/yr}\times\left(\frac{313.2 \text{ Btu}}{\text{lb steam}}\right)\times\frac{2.931\times10^{-4} \text{ kilowatt-hr}}{\text{Btu}}\times\frac{\text{megawatt-hr}}{1000 \text{ kilowatt-hr}}$$

$$S = 283{,}567 \text{ megawatt-hr/yr}$$

EXHIBIT 8.7: Cogeneration Emissions Allocation –Work Potential Allocation Method, continued

Step 3: Calculate Electricity and Steam Emission Factors

The third step is to apply Equation 8-11 for allocating emissions between the electricity and steam energy to generate emission factors.

$$\mathrm{EF} = \frac{435{,}983 \text{ tonnes } \mathrm{CO_2e}}{283{,}567 \text{ megawatt-hr}_{\text{steam}} + 1{,}100{,}600 \text{ megawatt-hr}_{\text{electricity}}}$$

$$\mathrm{EF} = 0.315 \text{ tonne } \mathrm{CO_2e/megawatt\text{-}hr}$$

Step 4: Apply Emission Factor to Estimate Emissions

The emissions associated with exported electricity and steam are determined by applying the appropriate MW-hrs to this emission factor.

CO_2 Equivalent Emissions for electricity sold to the refinery ($E_{Elec,\ ref}$):

$$E_{\text{Elec, ref}} = \frac{0.315 \text{ tonnes } \mathrm{CO_2}}{\text{megawatt-hr electricity}} \times 206{,}000 \text{ megawatt-hr}$$

$$E_{\text{Elec, ref}} = 64{,}890 \text{ tonnes } \mathrm{CO_2e} \text{ (Direct, Cogen; Indirect, Refinery)}$$

CO_2 Equivalent Emissions for electricity sold to the grid ($E_{Elec,\ grid}$):

$$E_{\text{Elec, grid}} = \frac{0.315 \text{ tonnes } \mathrm{CO_2}}{\text{megawatt-hr electricity}} \times 856{,}100 \text{ megawatt-hr}$$

$$E_{\text{Elec, grid}} = 269{,}672 \text{ tonnes } \mathrm{CO_2e} \text{ (Direct, Cogen; Indirect, Grid)}$$

EXHIBIT 8.7: Cogeneration Emissions Allocation – Work Potential Allocation Method, continued

CO_2 Equivalent Emissions for steam sold to the refinery ($E_{Steam,\ ref}$):

$$E_{\text{Steam, ref}} = 2{,}710{,}000 \times 10^6 \text{ Btu steam} \times \frac{283{,}567 \text{ megawatt-hr/yr}}{3{,}614{,}000 \times 10^6 \text{ Btu steam}}$$

$$E_{\text{Steam, ref}} = 212{,}636 \text{ megawatt-hr/yr}$$

$$E_{\text{Steam, ref}} = \frac{0.315 \text{ tonnes CO}_2}{\text{megawatt-hr steam}} \times 212{,}636 \text{ megawatt-hr}$$

$$E_{\text{Steam, ref}} = 66{,}980 \text{ tonnes CO}_2\text{e (Direct, Cogen; Indirect, Refinery)}$$

Step 5: Calculate Net Cogeneration Facility Emissions

Net cogeneration facility emissions are calculated by subtracting emissions from steam and electricity sold to the refinery, and electricity sold to the grid from the total emissions calculated in Step 1.

Net Cogeneration Facility CO_2 Emissions (E_{Net}):

$$E_{\text{Net}} = 435{,}983 \text{ tonnes CO}_2\text{e-}\left(64{,}890{+}269{,}672{+}66{,}980 \text{ tonnes CO}_2\text{e}\right)$$

$$E_{\text{Net}} = 34{,}441 \text{ tonnes CO}_2\text{e (Direct, Cogen)}$$

The following table summarizes the results for the work potential method.

EXHIBIT 8.7: Cogeneration Emissions Allocation – Work Potential Allocation Method, continued

Summary of Cogeneration Emissions – Work Potential Allocation Method

	Emissions, tonnes CO$_2$e	
Cogeneration Facility (Direct, Cogen)		
Direct Emissions from Fuel Consumption	435,983	
Emissions Associated with Electricity Sold to the Grid (Direct, Cogen, and Indirect, Grid Consumer)	269,672	Sums to 435,983
Net Facility Emissions	34,441	
Refinery Emissions (Direct, Cogen; Indirect, Refinery)		
Purchased electricity	64,890	
Purchased Steam	66,980	

8.2.2 Cogeneration Within An Entity

In cases where the energy streams from a cogeneration unit are consumed by the same entity that produced the energy streams, there is no need to allocate emissions among the streams. Direct emissions from the combustion of fuels to generate the energy streams are accounted for as direct emissions (i.e., Scope 1) in the entity's inventory.

There may, however, be situations within an entity where the energy streams cogenerated by one facility are consumed by one or more other facilities owned or operated by the entity. Within the entity's boundary, these emissions should be accounted for as direct emissions (Scope 1 per The GHG Protocol; WRI/WBCSD, 2004). The facility that purchases or consumes the electricity or heat output streams should not also account for the emissions associated with these streams as indirect emissions.

8.2.3 Cogeneration of Product Streams and Heat

Other processes associated with oil and gas industry operations (e.g., hydrogen and coke production) co-produce product streams with heat/steam. The basic principles demonstrated above can be applied to allocate emissions based on the energy content of the output streams and products. For example, the energy content method presented in Section 8.2.1 can be applied to allocate emissions based on the amount of energy in the steam and the Btu content of the produced coke or hydrogen.

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Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Natural Gas and Oil Industry

Appendix A – Additional Combustion Calculation Information

November 2021

Table of Contents

List of Tables

A. ADDITIONAL COMBUSTION CALCULATION INFORMATION

This section presents supplemental information for the combustion emission calculation methodologies presented in Section 4.

A.1 Methodology for Converting Between LHV and HHV Bases

Section 4.2 provides the equations for converting emission factors between a HHV and a LHV basis for gaseous and solid/liquid fuels in Equations 4-7 and 4-8, respectively. These equations can be simplified, and are shown in their simplified form in the footnotes to certain tables in Section 4. Fuel-based emission factors may be reported in terms of energy on a HHV or LHV basis. Converting emission factors between a LHV and HHV basis is different than converting between lower and higher heating values. This subsection provides the derivation of the simplified forms of the equations.

A.1.1 Solid Fuels

Derivation of the emission factor conversion for a solid fuel is provided below.

Starting with the IPCC assumption that LHV is 5% lower than HHV for a solid-based fuel:

$$\text{LHV}\left(\frac{\text{energy}}{\text{mass}}\right) = \text{HHV}\left(\frac{\text{energy}}{\text{mass}}\right) \text{- 5\% HHV}\left(\frac{\text{energy}}{\text{mass}}\right)$$

$$\text{LHV}\left(\frac{\text{energy}}{\text{mass}}\right) = \text{HHV}\left(\frac{\text{energy}}{\text{mass}}\right)(1\text{-}0.05) = 0.95\ \text{HHV}\left(\frac{\text{energy}}{\text{mass}}\right)$$

The heating value is converted to an emission factor as shown:

$$\text{EF}\left(\frac{\text{mass CO}_2}{\text{energy}}\right) = \frac{\text{X mass C}}{\text{mass fuel}} \times \frac{\text{mole C}}{\text{12 mass units C}} \times \frac{\text{mole CO}_2}{\text{mole C}} \times \frac{\text{44 mass units CO}_2}{\text{mole CO}_2} \times \frac{\text{mass fuel}}{\text{energy fuel}}$$

where

X = carbon content of the fuel;
12 = molecular weight of carbon;
mole CO_2/ mole C = carbon to CO_2 conversion (assuming 100% carbon oxidation);
44 = molecular weight of CO_2; and
mass fuel/energy fuel = inverse heating value of the fuel.

For an emission factor in terms of higher heating value:

$$\mathrm{EF}\left(\frac{\text{mass CO}_2}{\text{energy}}\right)_{\mathrm{HHV}} = \frac{\left(\frac{44X}{12}\right)\text{mass CO}_2}{\text{mass fuel}} \times \frac{1}{\mathrm{HHV}}\left(\frac{\text{mass fuel}}{\text{energy}}\right)$$

Likewise, for an emission factor in terms of lower heating value:

$$\mathrm{EF}\left(\frac{\text{mass CO}_2}{\text{energy}}\right)_{\mathrm{LHV}} = \frac{\left(\frac{44X}{12}\right)\text{mass CO}_2}{\text{mass fuel}} \times \frac{1}{\mathrm{LHV}}\left(\frac{\text{mass fuel}}{\text{energy}}\right)$$

To convert from a HHV-based emission factor to LHV:

$$\mathrm{EF}\left(\frac{\text{mass CO}_2}{\text{energy}}\right)_{\mathrm{LHV}} = \frac{\left(\frac{44X}{12}\right)\text{mass CO}_2}{\text{mass fuel}} \times \frac{1}{\mathrm{LHV}}\left(\frac{\text{mass fuel}}{\text{energy}}\right) \times \frac{\mathrm{LHV}}{0.95\ \mathrm{HHV}}$$

or expressed more simply:

$$\mathrm{EF}_{\mathrm{LHV}} = \frac{\mathrm{EF}_{\mathrm{HHV}}}{0.95}$$

A.1.2 Liquid Fuels

The approach used for solid fuels would also apply for a liquid fuel, except that the heating value of a liquid fuel is typically reported in terms of energy per volume. The fuel carbon content may be available on a mass, volume, or molar basis. As long as the units are internally consistent, the resulting equation to convert from LHV to HHV is the same as presented for the solid fuels. This is illustrated in the following.

Starting with the IPCC assumption that LHV is 5% lower than HHV for a liquid-based fuel:

$$\mathrm{LHV}\left(\frac{\mathrm{energy}}{\mathrm{volume}}\right)=\mathrm{HHV}\left(\frac{\mathrm{energy}}{\mathrm{volume}}\right)\text{-5\% HHV}\left(\frac{\mathrm{energy}}{\mathrm{volume}}\right)$$

$$\mathrm{LHV}\left(\frac{\mathrm{energy}}{\mathrm{volume}}\right)=\mathrm{HHV}\left(\frac{\mathrm{energy}}{\mathrm{volume}}\right)\left(1\text{-}0.05\right)=0.95\ \mathrm{HHV}\left(\frac{\mathrm{energy}}{\mathrm{volume}}\right)$$

The heating value is converted to an emission factor, similar to the approach shown for a solid fuel. Additional unit conversions and a fuel density may be required to convert the units appropriately:

$$\mathrm{EF}\left(\frac{\text{mass CO}_2}{\text{energy}}\right)=\frac{\text{mass fuel}}{\text{volume fuel}}\times\frac{\text{X mass C}}{\text{mass fuel}}\times\frac{\text{mole C}}{\text{12 mass units C}}\times\frac{\text{mole CO}_2}{\text{mole C}}$$
$$\times\frac{\text{44 mass units CO}_2}{\text{mol CO}_2}\times\frac{\text{volume fuel}}{\text{energy fuel}}$$

where

mass fuel/volume fuel = fuel density; and
volume fuel/energy fuel = inverse heating value of the fuel

For an emission factor in terms of higher heating value:

$$\mathrm{EF}\left(\frac{\text{mass CO}_2}{\text{energy}}\right)_{\mathrm{HHV}}=\text{density}\left(\frac{\text{mass fuel}}{\text{volume fuel}}\right)\times\frac{\left(\frac{44\mathrm{X}}{12}\right)\text{mass CO}_2}{\text{mass fuel}}\times\frac{1}{\mathrm{HHV}}\left(\frac{\text{volume fuel}}{\text{energy}}\right)$$

Likewise, for an emission factor in terms of lower heating value:

$$\mathrm{EF}\left(\frac{\text{mass CO}_2}{\text{energy}}\right)_{\mathrm{LHV}}=\text{density}\left(\frac{\text{mass fuel}}{\text{volume fuel}}\right)\times\frac{\left(\frac{44\mathrm{X}}{12}\right)\text{mass CO}_2}{\text{mass fuel}}\times\frac{1}{\mathrm{LHV}}\left(\frac{\text{volume fuel}}{\text{energy}}\right)$$

To convert from a HHV-based emission factor to LHV:

$$\mathrm{EF}\left(\frac{\text{mass CO}_2}{\text{energy}}\right)_{\mathrm{LHV}}=\text{density}\left(\frac{\text{mass fuel}}{\text{vol. fuel}}\right)\times\frac{\left(\frac{44\mathrm{X}}{12}\right)\text{mass CO}_2}{\text{mass fuel}}\times\frac{1}{\mathrm{LHV}}\left(\frac{\text{vol. fuel}}{\text{energy}}\right)\times\frac{\mathrm{LHV}}{0.95\ \mathrm{HHV}}$$

or expressed more simply:

$$\mathrm{EF}_{\mathrm{LHV}}=\frac{\mathrm{EF}_{\mathrm{HHV}}}{0.95}$$

A.1.3 Gases

A gas fuel would be treated like a liquid fuel, except that the LHV is 10% lower than the HHV, as shown:

$$\mathrm{LHV}\left(\frac{\text{energy}}{\text{volume}}\right)=\mathrm{HHV}\left(\frac{\text{energy}}{\text{volume}}\right)\text{-10\% HHV}\left(\frac{\text{energy}}{\text{volume}}\right)$$

$$\mathrm{LHV}\left(\frac{\text{energy}}{\text{volume}}\right)=\mathrm{HHV}\left(\frac{\text{energy}}{\text{volume}}\right)(1\text{-}0.10)=0.90\ \mathrm{HHV}\left(\frac{\text{energy}}{\text{volume}}\right)$$

Following the same approach as shown for the liquid fuel, the emission factor conversion for a gas fuel is:

$$\mathrm{EF}_{\mathrm{LHV}}=\frac{\mathrm{EF}_{\mathrm{HHV}}}{0.90}$$

A.2 Additional Stationary Combustion Emission Factors

A.2.1 Combustion Emission Factor Comparison for Industrial Equipment

The Climate Registry presents default CH_4 and N_2O emission factors by technology type for industrial combustion sources. The factors are taken from IPCC's *Guidelines for National Greenhouse Gas Inventories* (IPCC, 2006), Volume 2, Chapter 2: Stationary Combustion. IPCC cites US EPA's Air Clearinghouse for Inventories and Emission Factors (CHIEF) (EPA, 2005) as the original source of the emission factors. Air CHIEF pulls emission factors from EPA references, including AP-42, FIRE, and EIIP. Because EPA presents emission factors on a HHV basis, IPCC converted the Air CHIEF emission factors to a LHV basis using the methodology described in Section 4.2. The emission factors were then provided by IPCC in units of kg/TJ energy input up to one decimal place. TCR then converted the IPCC factors back from LHV to HHV, converted the units from kg/TJ to g/MMBtu, and presented the results up to one decimal place.

The majority of the emission factors presented in Table 4-9, 4-10, and 4-11 are taken directly from AP-42.

Tables A-1 and A-2 compare the API *Compendium's* emission factors to TCR's emission factors for external combustion and internal combustion sources, respectively. As shown in Table A-1, with the exception of the emission factors for N_2O for residual fuel oil boilers and gas/diesel oil boilers, and the factors for wood/wood waste boilers, the factors in the API *Compendium* match the factors in TCR. The emission factors for N_2O for residual fuel oil boilers and gas/diesel oil boilers do not match due to the fact that the IPCC N_2O factors for these sources were not revised with the Errata for AP-42 Section 1.3, dated 4/28/00. The emission factors for wood/wood waste boilers do not match because the *Compendium* Table 4-10 values were taken from a more recent reference from Environment Canada. The differences in emission factors presented in Table A-2 can be explained due to round off error.

Table A–1. External Combustion Industrial Source Emission Factor Comparison

		***Compendium* Factors**						**TCR Factors**	
		Original Units				**Converted Units**		**Original Units**	
		CH_4		**N_2O**		**CH_4**	**N_2O**	**CH_4**	**N_2O**
Fuel Type and Basic Technology	**Configuration**	**EF**	**Units**	**EF**	**Units**	**(g/MMBtu)**	**(g/MMBtu)**	**(g/MMBtu)**	**(g/MMBtu)**
Liquid Fuels[a]									
Residual fuel oil boilers[b]		1.00	lb/1000 gal	0.53	lb/1000 gal	3.0	1.6	3.0	0.3
Gas/diesel oil boilers[b]		0.052	lb/1000 gal	0.26	lb/1000 gal	0.2	0.8	0.2	0.4
Liquefied petroleum gases boilers		0.2	lb/1000 gal	0.9	lb/1000 gal	0.9	4.0	0.9	4.0
Solid Fuels[a]									
Other bituminous/sub-bit. Overfeed stoker boilers		0.06	lb/ton	0.04	lb/ton	1.0	0.7	1.0	0.7
Other bituminous/sub-bit. Underfeed stoker boilers		0.8	lb/ton	0.04	lb/ton	14	0.7	14	0.7
Other bituminous/sub-bituminous pulverized	Dry bottom, wall fired	0.04	lb/ton	0.03	lb/ton	0.7	0.5	0.7	0.5
	Dry bottom, tangentially fired	0.04	lb/ton	0.08	lb/ton	0.7	1.4	0.7	1.4
	Wet bottom	0.05	lb/ton	0.08	lb/ton	0.9	1.4	0.9	1.4
Other bituminous spreader stokers		0.06	lb/ton	0.04	lb/ton	1.0	0.7	1.0	0.7
Other bituminous/sub-bit. Fluidized bed combustor	Circulating bed	0.06	lb/ton	3.5	lb/ton	1.0	61.1	1.0	61.1
	Bubbling bed	0.06	lb/ton	3.5	lb/ton	1.0	61.1	1.0	61.1
Natural Gas[a]									
Boilers[c]		2.3	lb/10^6 scf	2.2	lb/10^6 scf	1.0	1.0	0.9	0.9
Biomass[d]									
Wood/Wood Waste Boilers		0.1	g/kg	0.07	g/kg	5.2	3.6	9.3	5.9

Footnotes and Sources:

API *Compendium*, Tables 4-9 and 4-10, 2021.

The Climate Registry (TCR). 2021 Default Emission Factor Document, Table 1.7, May 2021. Cites IPCC, *Guidelines for National Greenhouse Gas Inventories* (2006), Chapter 2: Stationary Combustion, Table 2.7. Values were converted from LHV (IPCC) to HHV (TCR).

[a] Residual fuel oil factors converted from lb/1000 gal to lb/MMBtu by dividing by 150 MMBtu/1000 gal, per AP-42, Section 1.3 (9/98). Distillate fuel oil factors converted from lb/1000 gal to lb/MMBtu by dividing by 140 MMBtu/1000 gal, per AP-42, Section 1.3 (9/98). LPG factors converted from lb/1000 gal to lb/MMBtu by dividing by 102 MMBtu/1000 gal (HHV for butane), per AP-42, Section 1.5 (7/08). Coal factors converted from lb/ton to lb/MMBtu by dividing by 26 MMBtu/ton, per AP-42, Section 1.1 (9/98). Natural gas factors converted from lb/10^6 scf to lb/MMBtu by dividing by 1020 MMBtu/10^6 scf, per AP-42, Section 1.4 (7/98).

[b] The TCR factors for N_2O for residual and gas/diesel oil boilers are citing an incorrect factor from IPCC. IPCC's factors were not revised with the Errata for AP-42 Section 1.3, dated 4/28/00.

[c] The natural gas boiler N_2O emission factor presented for the API *Compendium* is the uncontrolled factor.

[d] The conversions for wood/wood waste based on the default HHV for Wood and Wood Residuals (dry basis) from 40 CFR Part 98, Table C-1, *Default CO2 Emission Factors and High Heat Values for Various Types of Fuel.*

Table A–2. Internal Combustion Industrial Source Emission Factor Comparison

Fuel Type and Basic Technology	Configuration	Compendium Factors						TCR Factors	
		Original Units				Converted Units		Original Units	
		CH_4		N_2O		CH_4	N_2O	CH_4	N_2O
		EF	Units	EF	Units	(g/MMBtu)	(g/MMBtu)	(g/MMBtu)	(g/MMBtu)
Liquid Fuels									
Large stationary diesel oil engines >600 hp		0.0081	lb/10^6 Btu	NA		3.7	NA	4.0	NA
Natural Gas									
Gas-fired gas turbines >3MW[a]		0.0086	lb/10^6 Btu	0.003	lb/10^6 Btu	3.9	1.4	3.8	0.9
Natural gas-fired reciprocating engines	2-Stroke lean burn	1.45	lb/10^6 Btu	NA		657.7	NA	658.0	NA
	4-Stroke lean burn	1.25	lb/10^6 Btu	NA		567.0	NA	566.9	NA
	4-Stroke rich burn	0.23	lb/10^6 Btu	NA		104.3	NA	104.4	NA

Footnotes and Sources:

API *Compendium*, Table 4-11, 2021.

The Climate Registry (TCR). 2021 Default Emission Factor Document, Table 1.7, May 2021. Cites IPCC, Guidelines for National Greenhouse Gas Inventories (2006), Chapter 2: Stationary Combustion, Table 2.7. Values were converted from LHV (IPCC) to HHV (TCR).

[a] The gas-fired gas turbine >3MW factor is the same as the uncontrolled factor reported in Table 4-11.

A.2.2 Combustion Emissions Based on Equipment Manufacturer Data (Canadian)

Section 4.5.2 presents generic emission factors for internal combustion units. Tables A-3 and A-4 provide model-specific combustion emission factors for CH_4 and CO_2. These model-specific factors may be useful if a facility uses these specific types of engine drivers. Table A-3 applies to Waukesha reciprocating units and is taken from Table 1-7 of the CAPP document, *Calculating Greenhouse Gas Emissions* (CAPP, 2003). Table A-4 is appropriate for CAT reciprocating engines, and is taken from Table 1-8 of the CAPP document (CAPP, 2003).

The emission factors in Tables A-3 and A-4 are given on power output basis, but can be converted to a fuel input basis using the conversion factors for each type of engine given in Table 4.2 of this document. If available and applicable, model-specific conversion factors are more accurate than generic factors in Section 4. CAPP states that thermal efficiencies (higher heating value basis) for reciprocating engines typically are in the range of 28 to 31% for naturally aspirated engines and 31 to 36% for lean burn engines based on Waukesha engine specifications (CAPP, 2003). For gas-fired turbines, CAPP reports typical thermal efficiencies (HHV basis) of 24 to 30% based on Solar and GE manufacturer data (CAPP, 2003).

Carbon dioxide emission factors were not provided for several of the engine models shown in Tables A-3 and A-4. For these models, the user may want to use the fuel-based CO_2 estimation methodology or emission factors provided earlier in Sections 4.3 and 4.4. Also, model-specific N_2O emission factors are not available.

Table A–3. Waukesha Reciprocating Engines Combustion Emission Factors

Model	Carburetor Setting	Excess Air Ratio	Carbon Dioxide		Methane	
			Original Units, g/kW-hr	Converted to tonnes/kW-hr	Original Units, g/kW-hr	Converted to tonnes/kW-hr
AT25GL	Standard	1.74	580.8	5.808E-04	9.39	9.39E-06
AT27GL	Standard	1.74	Not Given		6.03	6.03E-06
	Ultra Lean	2.00	526.9	5.269E-04	4.16	4.16E-06
VHP G, GSI	Lowest manifold	0.97	581.29	5.8129E-04	2.61	2.61E-06
	Equal NO_x & CO	0.99	581.29	5.8129E-04	2.61	2.61E-06
	Catalytic converter	0.99	581.29	5.8129E-04	2.28	2.28E-06
	Standard	1.06	581.29	5.8129E-04	1.68	1.68E-06
VHP 3524 GSI	Equal NO_x & CO	0.99	576.13	5.7613E-04	1.14	1.14E-06
VHP 7044 GSI	Catalytic converter	0.99	573.7	5.737E-04	1.07	1.07E-06
	Standard	1.06	Not Given		0.80	8.0E-07
VHP 5794 GSI	Equal NO_x & CO	0.99	568.7	5.687E-04	3.42	3.42E-06
	Catalytic converter	0.99	Not Given		3.29	3.29E-06
	Standard	1.06	Not Given		2.75	2.75E-06
VHP GL	Standard	1.74	592.3	5.923E-04	6.03	6.03E-06
VGF Model G	Lowest manifold	0.97	575.0	5.750E-04	2.28	2.28E-06
	Equal NO_x & CO	0.98	Not Given		2.28	2.28E-06
	Catalytic converter	0.99	Not Given		2.28	2.28E-06
	Standard	1.12	Not Given		1.41	1.41E-06
VGF Model GSID	Catalytic converter	0.99	575.0	5.750E-04	1.68	1.68E-06
VGF GL, GLD 11:1 CR	Std.: high speed turbo	1.53	575.0	5.750E-04	5.7	5.7E-06
	T.A. Luft emissions	1.59	Not Given		4.09	4.09E-06
VGF GL 8.7:1 CR	Std.: high speed turbo	1.53	575.0	5.750E-04	4.09	4.09E-06
VSG G, GSI, GSID	Lowest manifold	0.97	566.8	5.668E-04	3.42	3.42E-06
	Equal NO_x & CO	0.98	Not Given		3.42	3.42E-06
	Catalytic converter	0.99	Not Given		3.08	3.08E-06
	Standard	1.10	Not Given		2.28	2.28E-06
F1197G G	Lowest manifold	0.97	Not Given		3.35	3.35E-06
	Equal NO_x & CO	1.0	Not Given		2.61	2.61E-06
	Catalytic converter	0.99	Not Given		2.61	2.61E-06
	Standard	1.06	Not Given		1.27	1.27E-06
F8176 G	Lowest manifold	0.97	Not Given		2.61	2.61E-06
	Equal NO_x & CO	1.0	Not Given		2.28	2.28E-06
	Catalytic converter	0.99	Not Given		2.28	2.28E-06
	Standard	1.06	Not Given		2.28	2.28E-06

Footnotes and Sources:

Canadian Association of Petroleum Producers (CAPP), *Calculating Greenhouse Gas Emissions*, Table 1-7, Canadian Association of Petroleum Producers, Publication Number 2003-03, April 2003.

Note: All data in this table are based on maximum horsepower and engine speed. "Lowest manifold" setting refers to best power setting while "Standard" setting refers to best economy setting.

Table A–4. CAT Reciprocating Engines Combustion Emission Factors

	Power	Speed		Carbon Dioxide	
Model	**kW**	**rpm**	**% O2**	**Original Units, g/kWh**	**Converted to tonnes/kW-hr**
3412 SITA	447	1800	1.5	436	4.36E-04
3508 SITA	384	1200	7.7	574	5.74E-04
	470	1400	8.0	590	5.90E-04
3512 SITA	604	1200	8.2	579	5.79E-04
	705	1400	7.7	595	5.95E-04
3516 SITA	809	1200	8.3	567	5.67E-04
	943	1200	7.9	581	5.81E-04
3606 SITA	1242	1000	12.3	347	3.47E-04
3608 SITA	1659	1000	12.3	347	3.47E-04
3612 SITA	2487	1000	12.3	347	3.47E-04
3616 SITA	3315	1000	12.3	347	3.47E-04
G398 TALCR	522	1200	2.0	Not Given	
G398 TAHCR Catalyst	522	1200	2.0	Not Given	
	522	1200	0.5	Not Given	
G398 TAHCR 32C (low emissions)	522	1200	6.2	Not Given	

Source:
Canadian Association of Petroleum Producers (CAPP), *Calculating Greenhouse Gas Emissions*, Table 1-7, Canadian Association of Petroleum Producers, Publication Number 2003-03, April 2003.

Exhibit A.1 illustrates the use of the model-specific CH_4 and CO_2 combustion emission factors.

EXHIBIT A.1: Sample Calculation for Combustion Emissions Model-Specific Basis for Internal Combustion Device

INPUT DATA:
A 500-kW Waukesha Model AT25GL internal combustion engine is operated for 1000 hours at 90% load during the reporting year. The unit uses a "standard" carburetor setting. Calculate the CH_4 and CO_2 emissions from this source.

CALCULATION METHODOLOGY:
The engine power output is multiplied by the model specific emission factors from Table A-3. Note that an emission factor for N_2O for this engine type is not available.

The annual power output from the unit is calculated as:

$$P = 500 \text{ kW} \times 0.90 \times \frac{1000 \text{ hr}}{\text{yr}} = 450{,}000 \text{ kW-hr/yr}$$

EXHIBIT A.1: Sample Calculation for Combustion Emissions Model-Specific Basis for Internal Combustion Device, continued

The emissions are calculated as:

$$E_{CH_4} = \frac{450{,}000 \text{ kW-hr}}{\text{yr}} \times \frac{9.39 \times 10^{-6} \text{ tonne } CH_4}{\text{kW-hr}}$$

$$\underline{E_{CH_4} = 4.2 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2} = \frac{450{,}000 \text{ kW-hr}}{\text{yr}} \times \frac{5.808 \times 10^{-4} \text{ tonne } CO_2}{\text{kW-hr}}$$

$$\underline{E_{CO_2} = 261 \text{ tonnes } CO_2/\text{yr}}$$

A.3 Mobile Source Combustion Emissions - Operational Basis

If mobile source fuel consumption is not available, or operational parameters cannot be used in such a way as to obtain fuel consumed, an alternate method for calculating emissions from mobile sources is to use non-fuel consumption data, such as distance traveled or power output.

A.3.1 On-Road Vehicles

Table A-5 provide simplified CO_2 emission factors for mobile sources (vehicles) in the United Kingdom based on distance traveled. Table A-6 presents similar factors for CH_4 and N_2O. These emission factors are based on guidance from the United Kingdom Department for Business, Energy & Industrial Strategy (BEIS, 2021).

Table A–5. Default Distance-Based CO_2 Mobile Source Emission Factors for the United Kingdom

Source	Original Units		Converted to	
	kg CO_2/mile	kg CO_2/km	tonnes CO_2/mile	tonnes CO_2/km
Small gasoline (petrol) car, up to 1.4 liter engine	0.23943	0.14878	0.00023943	0.00014878
Medium gasoline (petrol) car, 1.4 to 2.0 liter engine	0.30122	0.18717	0.00030122	0.00018717
Large gasoline (petrol) car, above 2.0 liter engine	0.44805	0.27841	0.00044805	0.00027841
Average gasoline (petrol) car	0.27944	0.17363	0.00027944	0.00017363
Small diesel car, up to 1.7 liter engine	0.21839	0.1357	0.00021839	0.0001357
Medium diesel car, 1.7 to 2.0 liter engine	0.26245	0.16308	0.00026245	0.00016308
Large diesel car, above 2.0 liter engine	0.33044	0.20533	0.00033044	0.00020533
Average diesel car	0.26804	0.16655	0.00026804	0.00016655
Small gasoline (petrol) hybrid car	0.16715	0.10386	0.00016715	0.00010386
Medium gasoline (petrol) hybrid car	0.17422	0.10825	0.00017422	0.00010825
Large gasoline (petrol) hybrid car	0.24129	0.14993	0.00024129	0.00014993
Average gasoline (petrol) hybrid car	0.19031	0.11825	0.00019031	0.00011825
Medium CNG car, 1.4 to 2.0 liter engine	0.25347	0.1575	0.00025347	0.0001575
Large CNG car, above 2.0 liter engine	0.37703	0.23427	0.00037703	0.00023427

Source:
United Kingdom Department for Business, Energy & Industrial Strategy. Greenhouse gas reporting: conversion factors 2021, June 2, 2021..

Table A–6 Default Distance-Based CH_4 and N_2O Mobile Source Emission Factors for the United Kingdom

Source	Original Units		Converted to		Original Units		Converted to	
	kg CH_4/mile	kg CH_4/km	tonnes CH_4/mile	tonnes CH_4/km	kg N_2O/mile	kg N_2O/km	tonnes N_2O/mile	tonnes N_2O/km
Small gasoline (petrol) car, up to 1.4 liter engine	0.00051	0.00032	5.10E-07	3.20E-07	0.00058	0.00036	5.80E-07	3.60E-07
Medium gasoline (petrol) car, 1.4 to 2.0 liter engine	0.00051	0.00032	5.10E-07	3.20E-07	0.00058	0.00036	5.80E-07	3.60E-07
Large gasoline (petrol) car, above 2.0 liter engine	0.00051	0.00032	5.10E-07	3.20E-07	0.00058	0.00036	5.80E-07	3.60E-07
Average gasoline (petrol) car	0.00051	0.00032	5.10E-07	3.20E-07	0.00058	0.00036	5.80E-07	3.60E-07
Small diesel car, up to 1.7 liter engine	0.00001	0.00000414	1.00E-08	4.14E-09	0.00303	0.00188	3.03E-06	1.88E-06
Medium diesel car, 1.7 to 2.0 liter engine	0.00001	0.00000414	1.00E-08	4.14E-09	0.00303	0.00188	3.03E-06	1.88E-06
Large diesel car, above 2.0 liter engine	0.00001	0.00000414	1.00E-08	4.14E-09	0.00303	0.00188	3.03E-06	1.88E-06
Average diesel car	0.00001	0.00000414	1.00E-08	4.14E-09	0.00303	0.00188	3.03E-06	1.88E-06
Small gasoline (petrol) hybrid car	0.00034	0.00021	3.40E-07	2.10E-07	0.0014	0.00087	1.40E-06	8.70E-07
Medium gasoline (petrol) hybrid car	0.00024	0.00015	2.40E-07	1.50E-07	0.00189	0.00117	1.89E-06	1.17E-06
Large gasoline (petrol) hybrid car	0.00014	0.00009	1.40E-07	9.00E-08	0.00239	0.00149	2.39E-06	1.49E-06
Average gasoline (petrol) hybrid car	0.00027	0.00017	2.70E-07	1.70E-07	0.00176	0.0011	1.76E-06	1.10E-06
Medium CNG car, 1.4 to 2.0 liter engine	0.00255	0.00158	2.55E-06	1.58E-06	0.00065	0.00041	6.50E-07	4.10E-07
Large CNG car, above 2.0 liter engine	0.00255	0.00158	2.55E-06	1.58E-06	0.00065	0.00041	6.50E-07	4.10E-07

Source:
United Kingdom Department for Business, Energy & Industrial Strategy. Greenhouse gas reporting: conversion factors 2021, June 2, 2021..

Table A-7 provides default CH_4 and N_2O distance-based emission factors by vehicle model year.

Table A–7. CH_4 and N_2O Emission Factors for Highway Vehicles by Model Year

Vehicle Type and Year	CH_4			N_2O		
	Original Units	Converted to		Original Units	Converted to	
	(g/mile)	(tonne/mile)	(tonne/km)	(g/mile)	(tonne/mile)	(tonne/km)
Gasoline Passenger Cars						
Model Years 1973-74	0.1696	1.70E-07	1.05E-07	0.0197	1.97E-08	1.22E-08
Model Year 1975	0.1423	1.42E-07	8.84E-08	0.0443	4.43E-08	2.75E-08
Model Years 1976-77	0.1406	1.41E-07	8.74E-08	0.0458	4.58E-08	2.85E-08
Model Years 1978-79	0.1389	1.39E-07	8.63E-08	0.0473	4.73E-08	2.94E-08
Model Year 1980	0.1326	1.33E-07	8.24E-08	0.0499	4.99E-08	3.10E-08
Model Year 1981	0.0802	8.02E-08	4.98E-08	0.0626	6.26E-08	3.89E-08
Model Year 1982	0.0795	7.95E-08	4.94E-08	0.0627	6.27E-08	3.90E-08
Model Year 1983	0.0782	7.82E-08	4.86E-08	0.0630	6.30E-08	3.91E-08
Model Years 1984-93	0.0704	7.04E-08	4.37E-08	0.0647	6.47E-08	4.02E-08
Model Year 1994	0.0617	6.17E-08	3.83E-08	0.0603	6.03E-08	3.75E-08
Model Year 1995	0.0531	5.31E-08	3.30E-08	0.056	5.60E-08	3.48E-08
Model Year 1996	0.0434	4.34E-08	2.70E-08	0.0503	5.03E-08	3.13E-08
Model Year 1997	0.0337	3.37E-08	2.09E-08	0.0446	4.46E-08	2.77E-08
Model Year 1998	0.0240	2.40E-08	1.49E-08	0.0389	3.89E-08	2.42E-08
Model Year 1999	0.0215	2.15E-08	1.34E-08	0.0355	3.55E-08	2.21E-08
Model Year 2000	0.0175	1.75E-08	1.09E-08	0.0304	3.04E-08	1.89E-08
Model Year 2001	0.0105	1.05E-08	6.52E-09	0.0212	2.12E-08	1.32E-08
Model Year 2002	0.0102	1.02E-08	6.34E-09	0.0207	2.07E-08	1.29E-08
Model Year 2003	0.0095	9.50E-09	5.90E-09	0.0181	1.81E-08	1.12E-08
Model Year 2004	0.0078	7.80E-09	4.85E-09	0.0085	8.50E-09	5.28E-09
Model Year 2005	0.0075	7.50E-09	4.66E-09	0.0067	6.70E-09	4.16E-09
Model Year 2006	0.0076	7.60E-09	4.72E-09	0.0075	7.50E-09	4.66E-09
Model Year 2007	0.0072	7.20E-09	4.47E-09	0.0052	5.20E-09	3.23E-09
Model Year 2008	0.0072	7.20E-09	4.47E-09	0.0049	4.90E-09	3.04E-09
Model Year 2009	0.0071	7.10E-09	4.41E-09	0.0046	4.60E-09	2.86E-09
Model Year 2010	0.0071	7.10E-09	4.41E-09	0.0046	4.60E-09	2.86E-09
Model Year 2011	0.0071	7.10E-09	4.41E-09	0.0046	4.60E-09	2.86E-09
Model Year 2012	0.0071	7.10E-09	4.41E-09	0.0046	4.60E-09	2.86E-09
Model Year 2013	0.0071	7.10E-09	4.41E-09	0.0046	4.60E-09	2.86E-09
Model Year 2014	0.0071	7.10E-09	4.41E-09	0.0046	4.60E-09	2.86E-09
Model Year 2015	0.0068	6.80E-09	4.23E-09	0.0042	4.20E-09	2.61E-09
Model Year 2016	0.0065	6.50E-09	4.04E-09	0.0038	3.80E-09	2.36E-09

Table A-7. CH_4 and N_2O Emission Factors for Highway Vehicles by Model Year, continued

Vehicle Type and Year	**CH_4**			**N_2O**		
	Original Units	**Converted to**		**Original Units**	**Converted to**	
	(g/mile)	**(tonne/mile)**	**(tonne/km**	**(g/mile)**	**(tonne/mile)**	**(tonne/km**
Model Year 2017	0.0054	5.40E-09	3.36E-09	0.0018	1.80E-09	1.12E-09
Model Year 2018	0.0052	5.20E-09	3.23E-09	0.0016	1.60E-09	9.94E-10
Model Years 1973-74	0.1908	1.91E-07	1.19E-07	0.0218	2.18E-08	1.35E-08
Model Year 1975	0.1634	1.63E-07	1.02E-07	0.0513	5.13E-08	3.19E-08
Model Year 1976	0.1594	1.59E-07	9.90E-08	0.0555	5.55E-08	3.45E-08
Model Years 1977-78	0.1614	1.61E-07	1.00E-07	0.0534	5.34E-08	3.32E-08
Model Years 1979-80	0.1594	1.59E-07	9.90E-08	0.0555	5.55E-08	3.45E-08
Model Year 1981	0.1479	1.48E-07	9.19E-08	0.0660	6.60E-08	4.10E-08
Model Year 1982	0.1442	1.44E-07	8.96E-08	0.0681	6.81E-08	4.23E-08
Model Year 1983	0.1368	1.37E-07	8.50E-08	0.0722	7.22E-08	4.49E-08
Model Year 1984	0.1294	1.29E-07	8.04E-08	0.0764	7.64E-08	4.75E-08
Model Year 1985	0.1220	1.22E-07	7.58E-08	0.0806	8.06E-08	5.01E-08
Model Year 1986	0.1146	1.15E-07	7.12E-08	0.0848	8.48E-08	5.27E-08
Model Years 1987-93	0.0813	8.13E-08	5.05E-08	0.1035	1.04E-07	6.43E-08
Model Year 1994	0.0646	6.46E-08	4.01E-08	0.0982	9.82E-08	6.10E-08
Model Year 1995	0.0517	5.17E-08	3.21E-08	0.0908	9.08E-08	5.64E-08
Model Year 1996	0.0452	4.52E-08	2.81E-08	0.0871	8.71E-08	5.41E-08
Model Year 1997	0.0452	4.52E-08	2.81E-08	0.0871	8.71E-08	5.41E-08
Model Year 1998	0.0412	4.12E-08	2.56E-08	0.0787	7.87E-08	4.89E-08
Model Year 1999	0.0333	3.33E-08	2.07E-08	0.0618	6.18E-08	3.84E-08
Model Year 2000	0.0340	3.40E-08	2.11E-08	0.0631	6.31E-08	3.92E-08
Model Year 2001	0.0221	2.21E-08	1.37E-08	0.0379	3.79E-08	2.36E-08
Model Year 2002	0.0242	2.42E-08	1.50E-08	0.0424	4.24E-08	2.63E-08
Model Year 2003	0.0221	2.21E-08	1.37E-08	0.0373	3.73E-08	2.32E-08
Model Year 2004	0.0115	1.15E-08	7.15E-09	0.0088	8.80E-09	5.47E-09
Model Year 2005	0.0105	1.05E-08	6.52E-09	0.0064	6.40E-09	3.98E-09
Model Year 2006	0.0108	1.08E-08	6.71E-09	0.0080	8.00E-09	4.97E-09
Model Year 2007	0.0103	1.03E-08	6.40E-09	0.0061	6.10E-09	3.79E-09
Model Year 2008	0.0095	9.50E-09	5.90E-09	0.0036	3.60E-09	2.24E-09
Model Year 2009	0.0095	9.50E-09	5.90E-09	0.0036	3.60E-09	2.24E-09
Model Year 2010	0.0095	9.50E-09	5.90E-09	0.0035	3.50E-09	2.17E-09
Model Year 2011	0.0096	9.60E-09	5.97E-09	0.0034	3.40E-09	2.11E-09
Model Year 2012	0.0096	9.60E-09	5.97E-09	0.0033	3.30E-09	2.05E-09
Model Year 2013	0.0095	9.50E-09	5.90E-09	0.0035	3.50E-09	2.17E-09
Model Year 2014	0.0095	9.50E-09	5.90E-09	0.0033	3.30E-09	2.05E-09
Model Year 2015	0.0094	9.40E-09	5.84E-09	0.0031	3.10E-09	1.93E-09

Table A-7. CH_4 and N_2O Emission Factors for Highway Vehicles by Model Year, continued

Vehicle Type and Year	CH_4			N_2O		
	Original Units	**Converted to**		**Original Units**		**Converted to**
	(g/mile)	**(tonne/mile)**	**(tonne/km**	**(g/mile)**	**(tonne/mile)**	**(tonne/km**
Model Year 2016	0.0091	9.10E-09	5.65E-09	0.0029	2.90E-09	1.80E-09
Model Year 2017	0.0084	8.40E-09	5.22E-09	0.0018	1.80E-09	1.12E-09
Model Year 2018	0.0081	8.10E-09	5.03E-09	0.0015	1.50E-09	9.32E-10
Gasoline Heavy-Duty Vehicles						
Model Years <1981	0.4604	4.60E-07	2.86E-07	0.0497	4.97E-08	3.09E-08
Model Years 1982-84	0.4492	4.49E-07	2.79E-07	0.0538	5.38E-08	3.34E-08
Model Years 1985-86	0.4090	4.09E-07	2.54E-07	0.0515	5.15E-08	3.20E-08
Model Year 1987	0.3675	3.68E-07	2.28E-07	0.0849	8.49E-08	5.28E-08
Model Years 1988-1989	0.3492	3.49E-07	2.17E-07	0.0933	9.33E-08	5.80E-08
Model Years 1990-1995	0.3246	3.25E-07	2.02E-07	0.1142	1.14E-07	7.10E-08
Model Year 1996	0.1278	1.28E-07	7.94E-08	0.1680	1.68E-07	1.04E-07
Model Year 1997	0.0924	9.24E-08	5.74E-08	0.1726	1.73E-07	1.07E-07
Model Year 1998	0.0655	6.55E-08	4.07E-08	0.1750	1.75E-07	1.09E-07
Model Year 1999	0.0648	6.48E-08	4.03E-08	0.1724	1.72E-07	1.07E-07
Model Year 2000	0.0630	6.30E-08	3.91E-08	0.1660	1.66E-07	1.03E-07
Model Year 2001	0.0577	5.77E-08	3.59E-08	0.1468	1.47E-07	9.12E-08
Model Year 2002	0.0634	6.34E-08	3.94E-08	0.1673	1.67E-07	1.04E-07
Model Year 2003	0.0602	6.02E-08	3.74E-08	0.1553	1.55E-07	9.65E-08
Model Year 2004	0.0298	2.98E-08	1.85E-08	0.0164	1.64E-08	1.02E-08
Model Year 2005	0.0297	2.97E-08	1.85E-08	0.0083	8.30E-09	5.16E-09
Model Year 2006	0.0299	2.99E-08	1.86E-08	0.0241	2.41E-08	1.50E-08
Model Year 2007	0.0322	3.22E-08	2.00E-08	0.0015	1.50E-09	9.32E-10
Model Year 2008	0.0340	3.40E-08	2.11E-08	0.0015	1.50E-09	9.32E-10
Model Year 2009	0.0339	3.39E-08	2.11E-08	0.0015	1.50E-09	9.32E-10
Model Year 2010	0.0320	3.20E-08	1.99E-08	0.0015	1.50E-09	9.32E-10
Model Year 2011	0.0304	3.04E-08	1.89E-08	0.0015	1.50E-09	9.32E-10
Model Year 2012	0.0313	3.13E-08	1.94E-08	0.0015	1.50E-09	9.32E-10
Model Year 2013	0.0313	3.13E-08	1.94E-08	0.0015	1.50E-09	9.32E-10
Model Year 2014	0.0315	3.15E-08	1.96E-08	0.0015	1.50E-09	9.32E-10
Model Year 2015	0.0332	3.32E-08	2.06E-08	0.0021	2.10E-09	1.30E-09
Model Year 2016	0.0321	3.21E-08	1.99E-08	0.0061	6.10E-09	3.79E-09
Model Year 2017	0.0329	3.29E-08	2.04E-08	0.0084	8.40E-09	5.22E-09
Model Year 2018	0.0326	3.26E-08	2.03E-08	0.0082	8.20E-09	5.10E-09

Table A-7. CH_4 and N_2O Emission Factors for Highway Vehicles by Model Year, continued

Vehicle Type and Year	CH_4 Original Units (g/mile)	CH_4 Converted to (tonne/mile)	CH_4 Converted to (tonne/km	N_2O Original Units (g/mile)	N_2O Converted to (tonne/mile)	N_2O Converted to (tonne/km
Diesel Passenger Cars						
Model Years 1960-1982	0.0006	6.00E-10	3.73E-10	0.0012	1.20E-09	7.46E-10
Model Years 1983-1995	0.0005	5.00E-10	3.11E-10	0.0010	1.00E-09	6.21E-10
Model Years 1996-2006	0.0005	5.00E-10	3.11E-10	0.0010	1.00E-09	6.21E-10
Model Years 2007-2018	0.0302	3.02E-08	1.88E-08	0.0192	1.92E-08	1.19E-08
Diesel Light-Duty Trucks						
Model Years 1960-1982	0.0011	1.10E-09	6.84E-10	0.0017	1.70E-09	1.06E-09
Model Years 1983-1995	0.0009	9.00E-10	5.59E-10	0.0014	1.40E-09	8.70E-10
Model Years 1996-2006	0.0010	1.00E-09	6.21E-10	0.0015	1.50E-09	9.32E-10
Model Years 2007-2018	0.0290	2.90E-08	1.80E-08	0.0214	2.14E-08	1.33E-08
Diesel Medium and Heavy-Duty Vehicles						
Model Years 1960-2006	0.0051	5.10E-09	3.17E-09	0.0048	4.80E-09	2.98E-09
Model Years 2007-2018	0.0095	9.50E-09	5.90E-09	0.0431	4.31E-08	2.68E-08

Source:
EPA, Greenhouse Gas Inventory Guidance - Direct Emissions from Mobile Combustion Sources, Table B-2, December 2020.

Tables A-8 provides CH_4 and N_2O emission factors for mobile sources (vehicles) in the U.S. based on distance traveled and number of cold starts. Combustion emissions can be calculated using a distance-based formula, as shown in Equation A-2:

$$E = (D \times EF_D) + (N_{CS} \times EF_{CS}) \qquad \text{(Equation A-2)}$$

where

D = vehicle distance traveled (km or miles);
EF_D = distance based emission factor (tonne/km or tonne/mi);
N_{CS} = number of cold starts; and
EF_{CS} = cold start emission factor (g/start or lb/start).

In its most recent *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2019*, EPA provides CH_4 and N_2O emission factors for various on-road vehicle types and control technologies based on distance traveled only (EPA, 2021). These factors are provided in Table A-9.

Table A–8. Default Distance Based CH_4 and N_2O Mobile Source Emission Factors for U.S. Vehicles

		CH_4					N_2O				
		Running (hot)			Cold Start		Running (hot)			Cold Start	
Vehicle Type	**Emission Control Technology**	**mg/km**	**tonne/km**	**tonne/mi**	**mg/start**	**tonne/start**	**mg/km**	**tonne/km**	**tonne/mi**	**mg/start**	**tonne/start**
Light Duty Gasoline Vehicle (Car)	Low Emission Vehicle (LEV)	6	6.00E-09	9.66E-09	32	3.20E-08	0	0	0	90	9.00E-08
	Advanced three-way catalyst	7	7.00E-09	1.13E-08	55	5.50E-08	9	9.00E-09	1.45E-08	113	1.13E-07
	Early three-way catalyst	39	3.90E-08	6.28E-08	34	3.40E-08	26	2.60E-08	4.18E-08	92	9.20E-08
	Oxidation catalyst	82	8.20E-08	1.32E-07	9	9.00E-09	20	2.00E-08	3.22E-08	72	7.20E-08
	Non-oxidation catalyst	96	9.60E-08	1.54E-07	59	5.90E-08	8	8.00E-09	1.29E-08	28	2.80E-08
	Uncontrolled	101	1.01E-07	1.63E-07	62	6.20E-08	8	8.00E-09	1.29E-08	28	2.80E-08
Light Duty Diesel Vehicle (Car)	Advanced	1	1.00E-09	1.61E-09	-3	-3.00E-09	1	1.00E-09	1.61E-09	0	0.00E+00
	Moderate	1	1.00E-09	1.61E-09	-3	-3.00E-09	1	1.00E-09	1.61E-09	0	0.00E+00
	Uncontrolled	1	1.00E-09	1.61E-09	-3	-3.00E-09	1	1.00E-09	1.61E-09	-1	-1.00E-09
Light Duty Gasoline Truck	Low Emission Vehicle (LEV)	7	7.00E-09	1.13E-08	46	4.60E-08	1	1.00E-09	1.61E-09	59	5.90E-08
	Advanced three-way catalyst	14	1.40E-08	2.25E-08	82	8.20E-08	25	2.50E-08	4.02E-08	200	2.00E-07
	Early three-way catalyst	39	3.90E-08	6.28E-08	72	7.20E-08	43	4.30E-08	6.92E-08	153	1.53E-07
	Oxidation catalyst	81	8.10E-08	1.30E-07	99	9.90E-08	26	2.60E-08	4.18E-08	93	9.30E-08
	Non-oxidation catalyst	109	1.09E-07	1.75E-07	67	6.70E-08	9	9.00E-09	1.45E-08	32	3.20E-08
	Uncontrolled	116	1.16E-07	1.87E-07	71	7.10E-08	9	9.00E-09	1.45E-08	32	3.20E-08
Light Duty Diesel Truck	Advanced and moderate	1	1.00E-09	1.61E-09	-4	-4.00E-09	1	1.00E-09	1.61E-09	-1	-1.00E-09
	Uncontrolled	1	1.00E-09	1.61E-09	-4	-4.00E-09	1	1.00E-09	1.61E-09	-1	-1.00E-09
Heavy Duty Gasoline Vehicle	Low Emission Vehicle (LEV)	14	1.40E-08	2.25E-08	94	9.40E-08	1	1.00E-09	1.61E-09	120	1.20E-07
	Advanced three-way catalyst	15	1.50E-08	2.41E-08	163	1.63E-07	52	5.20E-08	8.37E-08	409	4.09E-07
	Early three-way catalyst	121	1.21E-07	1.95E-07	183	1.83E-07	88	8.80E-08	1.42E-07	313	3.13E-07
	Oxidation catalyst	111	1.11E-07	1.79E-07	215	2.15E-07	55	5.50E-08	8.85E-08	194	1.94E-07
	Non-oxidation catalyst	239	2.39E-07	3.85E-07	147	1.47E-07	20	2.00E-08	3.22E-08	70	7.00E-08
	Heavy Duty Gasoline Vehicle - Uncontrolled	263	2.63E-07	4.23E-07	162	1.62E-07	21	2.10E-08	3.38E-08	74	7.40E-08
Heavy Duty Diesel Vehicle	All -advanced, moderate, or uncontrolled	4	4.00E-09	6.44E-09	-11	-1.10E-08	3	3.00E-09	4.83E-09	-2	-2.00E-09
Motorcycles	Non-oxidation catalyst	40	4.00E-08	6.44E-08	24	2.40E-08	3	3.00E-09	4.83E-09	12	1.20E-08
	Uncontrolled	53	5.30E-08	8.53E-08	33	3.30E-08	4	4.00E-09	6.44E-09	15	1.50E-08

Footnotes and Sources:

IPCC, *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, Volume 2, Chapter 3 (Mobile Combustion), Table 3.2.3, 2006.

Emission factors were converted from original units (mg/km; mg/start) and rounded to whole numbers. Negative emission factors indicate that a vehicle starting cold produces fewer emissions than a vehicle starting warm or running warm.

Implementation dates for vehicle control technologies vary by year. For a full description of implementation dates for U.S. vehicle control technologies, see the Inventory of U.S. Greenhouse Gases and Sinks: 1990-2019, Annexes, Table A-90 through A93 (EPA, 2021).

Table A–9. EPA CH_4 and N_2O Emission Factors for On-Road Vehicles by Control Technology

Vehicle Type/Control Technology	**Methane Emission Factor**						**Nitrous Oxide Emission Factors**					
	Original Units		**Converted Units**		**Converted Units**		**Original Units**		**Converted Units**		**Converted Units**	
	EF	**Units**	**EF**	**Units**	**EF**	**Units**	**EF**	**Units**	**EF**	**Units**	**EF**	**Units**
Gasoline Passenger Cars												
EPA Tier 3	0.006	g/mile	5.50E-09	tonne/ mile	3.42E-09	tonne/km	0.0015	g/mile	1.50E-09	tonne/ mile	9.32E-10	tonne/km
ARB LEV III	0.005	g/mile	4.50E-09	tonne/ mile	2.80E-09	tonne/km	0.0012	g/mile	1.20E-09	tonne/ mile	7.46E-10	tonne/km
EPA Tier 2	0.007	g/mile	7.20E-09	tonne/ mile	4.47E-09	tonne/km	0.0048	g/mile	4.80E-09	tonne/ mile	2.98E-09	tonne/km
ARB LEV II	0.007	g/mile	7.00E-09	tonne/ mile	4.35E-09	tonne/km	0.0043	g/mile	4.30E-09	tonne/ mile	2.67E-09	tonne/km
ARB LEV	0.01	g/mile	1.00E-08	tonne/ mile	6.21E-09	tonne/km	0.0205	g/mile	2.05E-08	tonne/ mile	1.27E-08	tonne/km
EPA Tier 1[a]	0.027	g/mile	2.71E-08	tonne/ mile	1.68E-08	tonne/km	0.0429	g/mile	4.29E-08	tonne/ mile	2.67E-08	tonne/km
EPA Tier 0[a]	0.07	g/mile	7.04E-08	tonne/ mile	4.37E-08	tonne/km	0.0647	g/mile	6.47E-08	tonne/ mile	4.02E-08	tonne/km
Oxidation Catalyst	0.136	g/mile	1.36E-07	tonne/ mile	8.42E-08	tonne/km	0.0504	g/mile	5.04E-08	tonne/ mile	3.13E-08	tonne/km
Non-Catalyst Control	0.17	g/mile	1.70E-07	tonne/ mile	1.05E-07	tonne/km	0.0197	g/mile	1.97E-08	tonne/ mile	1.22E-08	tonne/km
Uncontrolled	0.178	g/mile	1.78E-07	tonne/ mile	1.11E-07	tonne/km	0.0197	g/mile	1.97E-08	tonne/ mile	1.22E-08	tonne/km

Table A–9. EPA CH_4 and N_2O Emission Factors for On-Road Vehicles by Control Technology (continued)

Vehicle Type/Control Technology	Methane Emission Factors						Nitrous Oxide Emission Factors					
	Original Units		Converted Units		Converted Units		Original Units		Converted Units		Converted Units	
	EF	Units	EF	Units	EF	Units	EF	Units	EF	Units	EF	Units
Gasoline Light-Duty Trucks												
EPA Tier 3	0.009	g/mile	9.20E-09	tonne/ mile	5.72E-09	tonne/km	0.0012	g/mile	1.20E-09	tonne/ mile	7.46E-10	tonne/km
ARB LEV III	0.007	g/mile	6.50E-09	tonne/ mile	4.04E-09	tonne/km	0.0012	g/mile	1.20E-09	tonne/ mile	7.46E-10	tonne/km
EPA Tier 2	0.01	g/mile	1.00E-08	tonne/ mile	6.21E-09	tonne/km	0.0025	g/mile	2.50E-09	tonne/ mile	1.55E-09	tonne/km
ARB LEV II	0.008	g/mile	8.40E-09	tonne/ mile	5.22E-09	tonne/km	0.0057	g/mile	5.70E-09	tonne/ mile	3.54E-09	tonne/km
ARB LEV	0.015	g/mile	1.48E-08	tonne/ mile	9.20E-09	tonne/km	0.0223	g/mile	2.23E-08	tonne/ mile	1.39E-08	tonne/km
EPA Tier 1[a]	0.045	g/mile	4.52E-08	tonne/ mile	2.81E-08	tonne/km	0.0871	g/mile	8.71E-08	tonne/ mile	5.41E-08	tonne/km
EPA Tier 0[a]	0.078	g/mile	7.76E-08	tonne/ mile	4.82E-08	tonne/km	0.1056	g/mile	1.06E-07	tonne/ mile	6.56E-08	tonne/km
Oxidation Catalyst	0.152	g/mile	1.52E-07	tonne/ mile	9.42E-08	tonne/km	0.0639	g/mile	6.39E-08	tonne/ mile	3.97E-08	tonne/km
Non-Catalyst Control	0.191	g/mile	1.91E-07	tonne/ mile	1.19E-07	tonne/km	0.0218	g/mile	2.18E-08	tonne/ mile	1.35E-08	tonne/km
Uncontrolled	0.202	g/mile	2.02E-07	tonne/ mile	1.26E-07	tonne/km	0.0220	g/mile	2.20E-08	tonne/ mile	1.37E-08	tonne/km

Table A–9. EPA CH_4 and N_2O Emission Factors for On-Road Vehicles by Control Technology (continued)

Vehicle Type/Control Technology	**Methane Emission Factors**						**Nitrous Oxide Emission Factors**					
	Original Units		**Converted Units**		**Converted Units**		**Original Units**		**Converted Units**		**Converted Units**	
	EF	**Units**	**EF**	**Units**	**EF**	**Units**	**EF**	**Units**	**EF**	**Units**	**EF**	**Units**
Gasoline Heavy-Duty Trucks												
EPA Tier 3	0.025	g/mile	2.52E-08	tonne/ mile	1.57E-08	tonne/km	0.0063	g/mile	6.30E-09	tonne/ mile	3.91E-09	tonne/km
ARB LEV III	0.041	g/mile	4.11E-08	tonne/ mile	2.55E-08	tonne/km	0.0136	g/mile	1.36E-08	tonne/ mile	8.45E-09	tonne/km
EPA Tier 2	0.03	g/mile	2.97E-08	tonne/ mile	1.85E-08	tonne/km	0.0015	g/mile	1.50E-09	tonne/ mile	9.32E-10	tonne/km
ARB LEV II	0.039	g/mile	3.91E-08	tonne/ mile	2.43E-08	tonne/km	0.0049	g/mile	4.90E-09	tonne/ mile	3.04E-09	tonne/km
ARB LEV	0.03	g/mile	3.00E-08	tonne/ mile	1.86E-08	tonne/km	0.0466	g/mile	4.66E-08	tonne/ mile	2.90E-08	tonne/km
EPA Tier 1[a]	0.066	g/mile	6.55E-08	tonne/ mile	4.07E-08	tonne/km	0.1750	g/mile	1.75E-07	tonne/ mile	1.09E-07	tonne/km
EPA Tier 0[a]	0.263	g/mile	2.63E-07	tonne/ mile	1.63E-07	tonne/km	0.2135	g/mile	2.14E-07	tonne/ mile	1.33E-07	tonne/km
Oxidation Catalyst	0.236	g/mile	2.36E-07	tonne/ mile	1.46E-07	tonne/km	0.1317	g/mile	1.32E-07	tonne/ mile	8.18E-08	tonne/km
Non-Catalyst Control	0.418	g/mile	4.18E-07	tonne/ mile	2.60E-07	tonne/km	0.0473	g/mile	4.73E-08	tonne/ mile	2.94E-08	tonne/km
Uncontrolled	0.46	g/mile	4.60E-07	tonne/ mile	2.86E-07	tonne/km	0.0497	g/mile	4.97E-08	tonne/ mile	3.09E-08	tonne/km

Table A–9. EPA CH_4 and N_2O Emission Factors for On-Road Vehicles by Control Technology (continued)

Vehicle Type/Control Technology	Methane Emission Factors						Nitrous Oxide Emission Factors					
	Original Units		Converted Units		Converted Units		Original Units		Converted Units		Converted Units	
	EF	Units	EF	Units	EF	Units	EF	Units	EF	Units	EF	Units
Diesel Passenger Cars												
Aftertreatment	0.03	g/mile	3.02E-08	tonne/ mile	1.88E-08	tonne/km	0.0192	g/mile	1.92E-08	tonne/ mile	1.19E-08	tonne/km
Advanced	5E-04	g/mile	5.00E-10	tonne/ mile	3.11E-10	tonne/km	0.0010	g/mile	1.00E-09	tonne/ mile	6.21E-10	tonne/km
Moderate	5E-04	g/mile	5.00E-10	tonne/ mile	3.11E-10	tonne/km	0.0010	g/mile	1.00E-09	tonne/ mile	6.21E-10	tonne/km
Uncontrolled	6E-04	g/mile	6.00E-10	tonne/ mile	3.73E-10	tonne/km	0.0012	g/mile	1.20E-09	tonne/ mile	7.46E-10	tonne/km
Diesel Light-Duty Tracks												
Aftertreatment	0.029	g/mile	2.90E-08	tonne/ mile	1.80E-08	tonne/km	0.0214	g/mile	2.14E-08	tonne/ mile	1.33E-08	tonne/km
Advanced	9E-04	g/mile	9.00E-10	tonne/ mile	5.59E-10	tonne/km	0.0014	g/mile	1.40E-09	tonne/ mile	8.70E-10	tonne/km
Moderate	9E-04	g/mile	9.00E-10	tonne/ mile	5.59E-10	tonne/km	0.0014	g/mile	1.40E-09	tonne/ mile	8.70E-10	tonne/km
Uncontrolled	0.001	g/mile	1.00E-09	tonne/ mile	6.21E-10	tonne/km	0.0017	g/mile	1.70E-09	tonne/ mile	1.06E-09	tonne/km
Diesel Medium- and Heavy-Duty Trucks and Buses												
Aftertreatment	0.01	g/mile	9.50E-09	tonne/ mile	5.90E-09	tonne/km	0.0431	g/mile	4.31E-08	tonne/ mile	2.68E-08	tonne/km
Advanced	0.005	g/mile	5.10E-09	tonne/ mile	3.17E-09	tonne/km	0.0048	g/mile	4.80E-09	tonne/ mile	2.98E-09	tonne/km
Moderate	0.005	g/mile	5.10E-09	tonne/ mile	3.17E-09	tonne/km	0.0048	g/mile	4.80E-09	tonne/ mile	2.98E-09	tonne/km
Uncontrolled	0.005	g/mile	5.10E-09	tonne/ mile	3.17E-09	tonne/km	0.0048	g/mile	4.80E-09	tonne/ mile	2.98E-09	tonne/km

Table A–9. EPA CH_4 and N_2O Emission Factors for On-Road Vehicles by Control Technology (concluded)

Vehicle Type/Control Technology	**Methane Emission Factors**						**Nitrous Oxide Emission Factors**					
	Original Units		**Converted Units**		**Converted Units**		**Original Units**		**Converted Units**		**Converted Units**	
	EF	**Units**	**EF**	**Units**	**EF**	**Units**	**EF**	**Units**	**EF**	**Units**	**EF**	**Units**
Motorcycles												
Non-Catalyst Control	0.067	g/mile	6.72E-08	tonne/ mile	4.18E-08	tonne/km	0.0069	g/mile	6.90E-09	tonne/ mile	4.29E-09	tonne/km
Uncontrolled	0.09	g/mile	8.99E-08	tonne/ mile	5.59E-08	tonne/km	0.0087	g/mile	8.70E-09	tonne/ mile	5.41E-09	tonne/km

Source:
Inventory of U.S. Greenhouse Gases and Sinks: 1990-2019, Annexes, Table A-94 (EPA, 2021).

[a] The categories “EPA Tier 0” and “EPA Tier 1” were substituted for the early three-way catalyst and advanced three-way catalyst categories, respectively, as defined in the 2006 IPCC Guidelines. Detailed descriptions of emissions control technologies are provided at the end of the Annex.

Table A-10 provides CH_4 emission factors for European vehicles based on distance traveled and driving conditions from the joint *EMEP/EEA[1] Air Pollutant Emission Inventory Guidebook* (formerly called the EMEP CORINAIR emission inventory guidebook) (EEA, 2020). Combustion emissions can be calculated using the distance-based formula, as shown in Equation A-2. Note that the portion of emissions due to cold starts is not applicable to European vehicles because cold starts are incorporated into the appropriate emission factors. However, the distance traveled by European vehicles needs to be proportioned into distances traveled in urban cold, urban hot, rural, and highway conditions. IPCC notes that a typical allocation of the annual mileage of a passenger car into the different driving conditions could be: 0.3/0.1/0.3/0.3 for urban cold, urban hot, rural and highway respectively (IPCC, 2006).

For N2O, the EMEP/EEA *Air Pollutant Emission Inventory Guidebook* provides a different calculation methodology for gasoline passenger cars and gasoline light commercial vehicles (LCVs) than it does for other vehicle types. Gasoline passenger car and gasoline LCV N_2O emission factors are calculated by a formula (Equation 28) that requires cumulative vehicle mileage. If cumulative vehicle mileage is not available, Table A-11 provides N_2O emission factors based on the 2006 IPCC Guidelines for gasoline passenger cars and gasoline LCVs. Emission factors for N_2O for all other fuels and vehicle types from the EMEP/EEA Air Pollutant Emission Inventory Guidebook are provided in Table A-12.

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[1] EEA is the European Environmental Agency. The co-operative programme for monitoring and evaluation of the long-range transmission of air pollutants in Europe is unofficially the 'European Monitoring and Evaluation Programme' = EMEP) https://www.emep.int.

Table A–10. Default Distance Based CH_4 Mobile Source Emission Factors for European Vehicles

Vehicle Type	Fuel	Vehicle technology/ class	Original Units (mg/km)				Converted Units (tonne/km)				Converted Units (tonne/mile)			
			Urban				Urban				Urban			
			Cold	Hot	Rural	Highway	Cold	Hot	Rural	Highway	Cold	Hot	Rural	Highway
Passenger cars	Petrol-Hybrid Petrol-PHEV	Conventional	201	131	86	41	2.01E-07	1.31E-07	8.60E-08	4.10E-08	3.23E-07	2.11E-07	1.38E-07	6.60E-08
		Euro 1	45	26	16	14	4.50E-08	2.60E-08	1.60E-08	1.40E-08	7.24E-08	4.18E-08	2.57E-08	2.25E-08
		Euro 2	94	17	13	11	9.40E-08	1.70E-08	1.30E-08	1.10E-08	1.51E-07	2.74E-08	2.09E-08	1.77E-08
		Euro 3	83	3	2	4	8.30E-08	3.00E-09	2.00E-09	4.00E-09	1.34E-07	4.83E-09	3.22E-09	6.44E-09
		Euro 4 and later	57	2.87	2.69	5.1	5.70E-08	2.87E-09	2.69E-09	5.08E-09	9.17E-08	4.62E-09	4.33E-09	8.18E-09
	Diesel-PHEV	Conventional	22	28	12	8	2.20E-08	2.80E-08	1.20E-08	8.00E-09	3.54E-08	4.51E-08	1.93E-08	1.29E-08
		Euro 1	18	11	9	3	1.80E-08	1.10E-08	9.00E-09	3.00E-09	2.90E-08	1.77E-08	1.45E-08	4.83E-09
		Euro 2	6	7	3	2	6.00E-09	7.00E-09	3.00E-09	2.00E-09	9.66E-09	1.13E-08	4.83E-09	3.22E-09
		Euro 3	3	3	0	0	3.00E-09	3.00E-09	0	0	4.83E-09	4.83E-09	0	0
		Euro 4	1.1	1.1	0	0	1.10E-09	1.10E-09	0	0	1.77E-09	1.77E-09	0	0
		Euro 5 and later	0.075	0.075	0	0	7.50E-11	7.50E-11	0	0	1.21E-10	1.21E-10	0	0
	LPG	All Technologies	80	80	35	25	8.00E-08	8.00E-08	3.50E-08	2.50E-08	1.29E-07	1.29E-07	5.63E-08	4.02E-08
	E85	All Technologies	57	2.87	2.69	5.1	5.70E-08	2.87E-09	2.69E-09	5.08E-09	9.17E-08	4.62E-09	4.33E-09	8.18E-09

Table A–10. Default Distance Based CH_4 Mobile Source Emission Factors for European Vehicles (continued)

Vehicle Type	Fuel	Vehicle technology/ class	Original Units (mg/km)				Converted Units (tonne/km)				Converted Units (tonne/mile)			
			Urban				Urban				Urban			
			Cold	Hot	Rural	Highway	Cold	Hot	Rural	Highway	Cold	Hot	Rural	Highway
	CNG	All Technologies	*	57.3	27.7	43.4	*	5.73E-08	2.77E-08	4.34E-08	*	9.22E-08	4.46E-08	6.98E-08
Light commercial vehicles	Petrol	Conventional	201	131	86	41	2.01E-07	1.31E-07	8.60E-08	4.10E-08	3.23E-07	2.11E-07	1.38E-07	6.60E-08
		Euro 1	45	26	16	14	4.50E-08	2.60E-08	1.60E-08	1.40E-08	7.24E-08	4.18E-08	2.57E-08	2.25E-08
		Euro 2	94	17	13	11	9.40E-08	1.70E-08	1.30E-08	1.10E-08	1.51E-07	2.74E-08	2.09E-08	1.77E-08
		Euro 3	83	3	2	4	8.30E-08	3.00E-09	2.00E-09	4.00E-09	1.34E-07	4.83E-09	3.22E-09	6.44E-09
		Euro 4 and later	57	2	2	0	5.70E-08	2.00E-09	2.00E-09	0.00E+00	9.17E-08	3.22E-09	3.22E-09	0.00E+00
	Diesel	Conventional	22	28	12	8	2.20E-08	2.80E-08	1.20E-08	8.00E-09	3.54E-08	4.51E-08	1.93E-08	1.29E-08
		Euro 1	18	11	9	3	1.80E-08	1.10E-08	9.00E-09	3.00E-09	2.90E-08	1.77E-08	1.45E-08	4.83E-09
		Euro 2	6	7	3	2	6.00E-09	7.00E-09	3.00E-09	2.00E-09	9.66E-09	1.13E-08	4.83E-09	3.22E-09
		Euro 3	3	3	0	0.0	3.00E-09	3.00E-09	0	0	4.83E-09	4.83E-09	0	0
		Euro 4	1.1	1.1	0	0	1.10E-09	1.10E-09	0	0	1.77E-09	1.77E-09	0	0
		Euro 5 and later	0.0075	0.0075	0	0	7.50E-12	7.50E-12	0	0	1.21E-11	1.21E-11	0	0
Heavy-duty vehicles and buses	Petrol	All Technologies	-	140	110	70	-	1.40E-07	1.10E-07	7.00E-08	-	2.25E-07	1.77E-07	1.13E-07
	Diesel	GVW<16t	-	85	23	20	-	8.50E-08	2.30E-08	2.00E-08	-	1.37E-07	3.70E-08	3.22E-08
		GVW>16t	-	175	80	70	-	1.75E-07	8.00E-08	7.00E-08	-	2.82E-07	1.29E-07	1.13E-07
	Diesel-Biodiesel	Urban Buses and Coaches Hybrid Urban Buses	-	175	80	70	-	1.75E-07	8.00E-08	7.00E-08	-	2.82E-07	1.29E-07	1.13E-07
	CNG	Euro I	-	6800			-	6.80E-06			-	1.09E-05		
		Euro II	-	4500			-	4.50E-06			-	7.24E-06		
		Euro III	-	1280			-	1.28E-06			-	2.06E-06		
		EEV	-	980			-	9.80E-07			-	1.58E-06		

Table A–10. Default Distance Based CH_4 Mobile Source Emission Factors for European Vehicles (concluded)

Vehicle Type	Fuel	Vehicle technology/ class	Original Units (mg/km)				Converted Units (tonne/km)				Converted Units (tonne/mile)			
			Urban		Rural	Highway	Urban		Rural	Highway	Urban		Rural	Highway
			Cold	Hot			Cold	Hot			Cold	Hot		
L-Category[a]	Petrol	< 50 cm^3 2-stroke	-	219	219	219	-	2.19E-07	2.19E-07	2.19E-07	-	3.52E-07	3.52E-07	3.52E-07
		< 50 cm^3 4-stroke	-	219	219	219	-	2.19E-07	2.19E-07	2.19E-07	-	3.52E-07	3.52E-07	3.52E-07
		> 50 cm^3 2-stroke	-	150	150	150	-	1.50E-07	1.50E-07	1.50E-07	-	2.41E-07	2.41E-07	2.41E-07
		> 50 cm^3 4-stroke	-	200	200	200	-	2.00E-07	2.00E-07	2.00E-07	-	3.22E-07	3.22E-07	3.22E-07
	Mini-cars Diesel	Conventional	22	28	12	8	2.20E-08	2.80E-08	1.20E-08	8.00E-09	3.54E-08	4.51E-08	1.93E-08	1.29E-08
		Euro 1	18	11	9	3	1.80E-08	1.10E-08	9.00E-09	3.00E-09	2.90E-08	1.77E-08	1.45E-08	4.83E-09
		Euro 2	6	7	3	2	6.00E-09	7.00E-09	3.00E-09	2.00E-09	9.66E-09	1.13E-08	4.83E-09	3.22E-09
		Euro 3	3	3	0	0	3.00E-09	3.00E-09	0	0	4.83E-09	4.83E-09	0	0
		Euro 4	1.1	1.1	0	0	1.10E-09	1.10E-09	0	0	1.77E-09	1.77E-09	0	0
		Euro 5 and later	0.075	0.075	0	0	7.50E-11	7.50E-11	0	0	1.21E-10	1.21E-10	0	0
	ATVs	Conventional	-	200	200	200	-	2.00E-07	2.00E-07	2.00E-07	-	3.22E-07	3.22E-07	3.22E-07

Source:
EMEP/EEA air pollutant emission inventory guidebook 2019, 1.A.3.b.i-iv Road transport (EEA 2020).

Table A–11. Default Distance Based N_2O Mobile Source Emission Factors for European Vehicles - Gasoline Passenger Cars and Gasoline Light Duty Vehicles

Vehicle Type	Fuel	Vehicle technology /class	Original Units (mg/km)				Converted Units (tonne/km)				Converted Units (tonne/mile)			
			Urban		Rural	Highway	Urban		Rural	Highway	Urban		Rural	Highway
			Cold	Hot			Cold	Hot			Cold	Hot		
Passenger cars	Gasoline	pre-Euro	10	10	6.5	6.5	1.00E-08	1.00E-08	6.50E-09	6.50E-09	1.61E-08	1.61E-08	1.05E-08	1.05E-08
		Euro 1	38	22	17	8.0	3.80E-08	2.20E-08	1.70E-08	8.00E-09	6.12E-08	3.54E-08	2.74E-08	1.29E-08
		Euro 2	24	11	4.5	2.5	2.40E-08	1.10E-08	4.50E-09	2.50E-09	3.86E-08	1.77E-08	7.24E-09	4.02E-09
		Euro 3	12	3	2.0	1.5	1.20E-08	3.00E-09	2.00E-09	1.50E-09	1.93E-08	4.83E-09	3.22E-09	2.41E-09
		Euro 4	6	2	0.8	0.7	6.00E-09	2.00E-09	8.00E-10	7.00E-10	9.66E-09	3.22E-09	1.29E-09	1.13E-09
Light duty vehicles	Gasoline	pre-Euro	10	10	6.5	6.5	1.00E-08	1.00E-08	6.50E-09	6.50E-09	1.61E-08	1.61E-08	1.05E-08	1.05E-08
		Euro 1	122	52	52	52	1.22E-07	5.20E-08	5.20E-08	5.20E-08	1.96E-07	8.37E-08	8.37E-08	8.37E-08
		Euro 2	62	22	22	22	6.20E-08	2.20E-08	2.20E-08	2.20E-08	9.98E-08	3.54E-08	3.54E-08	3.54E-08
		Euro 3	36	5	5	5	3.60E-08	5.00E-09	5.00E-09	5.00E-09	5.79E-08	8.05E-09	8.05E-09	8.05E-09
		Euro 4	16	2	2	2	1.60E-08	2.00E-09	2.00E-09	2.00E-09	2.57E-08	3.22E-09	3.22E-09	3.22E-09

Footnotes and Source for Table A-11:
IPCC, *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, Volume 2, Chapter 3 (Mobile Combustion), Table 3.2.5, 2006.
Emission factors were converted from original units (mg/km).
Implementation dates for vehicle control technologies vary by year and may vary by member state. For a full description of implementation dates for European vehicle control technologies, see the *EMEP/EEA air pollutant emission inventory guidebook 2019*, October 2020.
The urban emission factor is divided into cold and hot for passenger cars and light duty trucks. The cold emission factor is relevant for trips which start with the engine at ambient temperature. A typical allocation of the annual mileage of a passenger car into the different driving conditions could be: 0.3/0.1/0.3/0.3 for urban cold, urban hot, rural and highway respectively.

Table A–12. Default Distance Based N_2O Mobile Source Emission Factors for European Vehicles - Diesel Cars and LCVs, LPG Cars and Motorcycles

Vehicle category	Original Units (mg/km)				Converted Units (tonne/km)				Converted Units (tonne/mile)			
	Urban Cold	Urban Hot	Rural	Highway	Urban Cold	Urban Hot	Rural	Highway	Urban Cold	Urban Hot	Rural	Highway
Diesel passenger cars and LCVs												
Conventional	0	0	0	0	0	0	0	0	0	0	0	0
Euro 1	0	2	4	4	0	2.00E-09	4.00E-09	4.00E-09	0	3.22E-09	6.44E-09	6.44E-09
Euro 2	3	4	6	6	3.00E-09	4.00E-09	6.00E-09	6.00E-09	4.83E-09	6.44E-09	9.66E-09	9.66E-09
Euro 3/4/5	15	9	4	4	1.50E-08	9.00E-09	4.00E-09	4.00E-09	2.41E-08	1.45E-08	6.44E-09	6.44E-09
Euro 6 up to 2016 / 2017-2019 / 2020+	9	11	4	4	9.00E-09	1.10E-08	4.00E-09	4.00E-09	1.45E-08	1.77E-08	6.44E-09	6.44E-09
LPG passenger cars												
Conventional	0	0	0	0	0	0	0	0	0	0	0	0
Euro 1	38	21	13	8	3.80E-08	2.10E-08	1.30E-08	8.00E-09	6.12E-08	3.38E-08	2.09E-08	1.29E-08
Euro 2	23	13	3	2	2.30E-08	1.30E-08	3.00E-09	2.00E-09	3.70E-08	2.09E-08	4.83E-09	3.22E-09
Euro 3	9	5	2	1	9.00E-09	5.00E-09	2.00E-09	1.00E-09	1.45E-08	8.05E-09	3.22E-09	1.61E-09
Euro 4	9	5	2	1	9.00E-09	5.00E-09	2.00E-09	1.00E-09	1.45E-08	8.05E-09	3.22E-09	1.61E-09
Euro 5	1.8	2.1	0.2	1	1.80E-09	2.10E-09	2.00E-10	1.00E-09	2.90E-09	3.38E-09	3.22E-10	1.61E-09
Euro 6	1.8	2.1	0.2	1	1.80E-09	2.10E-09	2.00E-10	1.00E-09	2.90E-09	3.38E-09	3.22E-10	1.61E-09
L-category [a]												
<50 cm^3	1		1	1	1.00E-09		1.00E-09	1.00E-09	1.61E-09		1.61E-09	1.61E-09
>50 cm^3 2-stroke	2		2	2	2.00E-09		2.00E-09	2.00E-09	3.22E-09		3.22E-09	3.22E-09
>50 cm^3 4-stroke	2		2	2	2.00E-09		2.00E-09	2.00E-09	3.22E-09		3.22E-09	3.22E-09

Source:

EMEP/EEA air pollutant emission inventory guidebook 2019, 1.A.3.b.i-iv Road transport (EEA 2020).

[a] L-Category are mopeds & motorcycles and includes mini cars and ATVs.

Table A–13. Default Distance Based N_2O Mobile Source Emission Factors for European Vehicles - Heavy Duty Vehicles

		Original Units (g/km)			Converted Units (tonne/km)			Converted Units (tonne/mile)		
HDV Category	**Technology**	**Urban**	**Rural**	**Highway**	**Urban**	**Rural**	**Highway**	**Urban**	**Rural**	**Highway**
Petrol > 3.5 t	Conventional	6	6	6	6.00E-06	6.00E-06	6.00E-06	9.66E-06	9.66E-06	9.66E-06
Rigid 7.5-12 t	Conventional	30	30	30	3.00E-05	3.00E-05	3.00E-05	4.83E-05	4.83E-05	4.83E-05
	HD Euro I	6	5	3	6.00E-06	5.00E-06	3.00E-06	9.66E-06	8.05E-06	4.83E-06
	HD Euro II	5	5	3	5.00E-06	5.00E-06	3.00E-06	8.05E-06	8.05E-06	4.83E-06
	HD Euro III	3	3	2	3.00E-06	3.00E-06	2.00E-06	4.83E-06	4.83E-06	3.22E-06
	HD Euro IV	6	7.2	5.8	6.00E-06	7.20E-06	5.80E-06	9.66E-06	1.16E-05	9.33E-06
	HD Euro V	15	19.8	17.2	1.50E-05	1.98E-05	1.72E-05	2.41E-05	3.19E-05	2.77E-05
	HD Euro VI	18.5	19	15	1.85E-05	1.90E-05	1.50E-05	2.98E-05	3.06E-05	2.41E-05
Rigid and articulated 12–28 t and coaches (all types)	Conventional	30	30	30	3.00E-05	3.00E-05	3.00E-05	4.83E-05	4.83E-05	4.83E-05
	HD Euro I	11	9	7	1.10E-05	9.00E-06	7.00E-06	1.77E-05	1.45E-05	1.13E-05
	HD Euro II	11	9	6.0	1.10E-05	9.00E-06	6.00E-06	1.77E-05	1.45E-05	9.66E-06
	HD Euro III	5	5	4.0	5.00E-06	5.00E-06	4.00E-06	8.05E-06	8.05E-06	6.44E-06
	HD Euro IV	11.2	13.8	11.4	1.12E-05	1.38E-05	1.14E-05	1.80E-05	2.22E-05	1.83E-05
	HD Euro V	29.8	40.2	33.6	2.98E-05	4.02E-05	3.36E-05	4.80E-05	6.47E-05	5.41E-05
	HD Euro VI	37	39	29	3.70E-05	3.90E-05	2.90E-05	5.95E-05	6.28E-05	4.67E-05

Table A–13. Default Distance Based N_2O Mobile Source Emission Factors for European Vehicles - Heavy Duty Vehicles (concluded)

HDV Category	Technology	Original Units (g/km)			Converted Units (tonne/km)			Converted Units (tonne/mile)		
		Urban	Rural	Highway	Urban	Rural	Highway	Urban	Rural	Highway
Rigid and articulated 28–34 t	Conventional	30	30	30	3.00E-05	3.00E-05	3.00E-05	4.83E-05	4.83E-05	4.83E-05
	HD Euro I	17	14	10	1.70E-05	1.40E-05	1.00E-05	2.74E-05	2.25E-05	1.61E-05
	HD Euro II	17	14	10	1.70E-05	1.40E-05	1.00E-05	2.74E-05	2.25E-05	1.61E-05
	HD Euro III	8	8	6	8.00E-06	8.00E-06	6.00E-06	1.29E-05	1.29E-05	9.66E-06
	HD Euro IV	17.4	21.4	17.4	1.74E-05	2.14E-05	1.74E-05	2.80E-05	3.44E-05	2.80E-05
	HD Euro V	45.6	61.6	51.6	4.56E-05	6.16E-05	5.16E-05	7.34E-05	9.91E-05	8.30E-05
	HD Euro VI	56.5	59.5	44.5	5.65E-05	5.95E-05	4.45E-05	9.09E-05	9.58E-05	7.16E-05
Articulated > 34 t	Conventional	30	30	30	3.00E-05	3.00E-05	3.00E-05	4.83E-05	4.83E-05	4.83E-05
	HD Euro I	18	15	11	1.80E-05	1.50E-05	1.10E-05	2.90E-05	2.41E-05	1.77E-05
	HD Euro II	18	15	10	1.80E-05	1.50E-05	1.00E-05	2.90E-05	2.41E-05	1.61E-05
	HD Euro III	9	9	7	9.00E-06	9.00E-06	7.00E-06	1.45E-05	1.45E-05	1.13E-05
	HD Euro IV	19	23.4	19.2	1.90E-05	2.34E-05	1.92E-05	3.06E-05	3.77E-05	3.09E-05
	HD Euro V	49	66.6	55.8	4.90E-05	6.66E-05	5.58E-05	7.89E-05	1.07E-04	8.98E-05
	HD Euro VI	61	64	48.0	6.10E-05	6.40E-05	4.80E-05	9.82E-05	1.03E-04	7.72E-05
Diesel urban busses (all types)	Conventional	30	-	-	3.00E-05	-	-	4.83E-05	-	-
	HD Euro I	12	-	-	1.20E-05	-	-	1.93E-05	-	-
	HD Euro II	12	-	-	1.20E-05	-	-	1.93E-05	-	-
	HD Euro III	6	-	-	6.00E-06	-	-	9.66E-06	-	-
	HD Euro IV	12.8	-	-	1.28E-05	-	-	2.06E-05	-	-
	HD Euro V	33.2	-	-	3.32E-05	-	-	5.34E-05	-	-
	HD Euro VI	41.5	-	-	4.15E-05	-	-	6.68E-05	-	-

Source:

EMEP/EEA air pollutant emission inventory guidebook 2019, 1.A.3.b.i-iv Road transport (EEA 2020).

Table A-14 provides CH_4 and N_2O emission factors for alternative fuel vehicles, based on distance traveled.

Table A–14. Default Distance Based CH_4 and N_2O Emission Factors for Alternative Fuel Vehicles

Vehicle Type and Year	CH_4			N_2O		
	Original Units	Converted to		Original Units	Converted to	
	(g/mile)	(tonne/mile)	(tonne/km)	(g/mile)	(tonne/mile)	(tonne/km)
Light-Duty Alternative Fuel Cars						
Methanol	0.008	8.00E-09	4.97E-09	0.006	6.00E-09	3.73E-09
Ethanol	0.008	8.00E-09	4.97E-09	0.006	6.00E-09	3.73E-09
CNG	0.082	8.20E-08	5.10E-08	0.006	6.00E-09	3.73E-09
LPG	0.008	8.00E-09	4.97E-09	0.006	6.00E-09	3.73E-09
Biodiesel	0.03	3.00E-08	1.86E-08	0.019	1.90E-08	1.18E-08
Light-Duty Alternative Fuel Trucks						
Ethanol	0.012	1.20E-08	7.46E-09	0.011	1.10E-08	6.84E-09
CNG	0.123	1.23E-07	7.64E-08	0.011	1.10E-08	6.84E-09
LPG	0.012	1.20E-08	7.46E-09	0.013	1.30E-08	8.08E-09
LNG	0.123	1.23E-07	7.64E-08	0.011	1.10E-08	6.84E-09
Biodiesel	0.029	2.90E-08	1.80E-08	0.021	2.10E-08	1.30E-08
Medium-Duty Alternative Fuel Trucks						
CNG	4.2	4.20E-06	2.61E-06	0.001	1.00E-09	6.21E-10
LPG	0.014	1.40E-08	8.70E-09	0.034	3.40E-08	2.11E-08
LNG	4.2	4.20E-06	2.61E-06	0.043	4.30E-08	2.67E-08
Biodiesel	0.009	9.00E-09	5.59E-09	0.001	1.00E-09	6.21E-10
Heavy-Duty Alternative Fuel Trucks						
Methanol	0.075	7.50E-08	4.66E-08	0.028	2.80E-08	1.74E-08
Ethanol	0.075	7.50E-08	4.66E-08	0.028	2.80E-08	1.74E-08
CNG	3.7	3.70E-06	2.30E-06	0.001	1.00E-09	6.21E-10
LPG	0.013	1.30E-08	8.08E-09	0.026	2.60E-08	1.62E-08
LNG	3.7	3.70E-06	2.30E-06	0.001	1.00E-09	6.21E-10
Biodiesel	0.009	9.00E-09	5.59E-09	0.043	4.30E-08	2.67E-08

Source:
EPA, GHG Emission Factor Hub, September 15, 2021.

Exhibit A.2 provides an illustration of how to calculate emissions from vehicles using an operational basis.

EXHIBIT A.2: Sample Operational Basis Calculation for Combustion Emissions from Vehicles

INPUT DATA:
A fleet of heavy-duty (HD) diesel freight trucks travels 1,000,000 miles during the year. The trucks are equipped with advance control systems. There were approximately 1,500 cold starts during the year. Calculate the CH_4 and N_2O emissions using a distance-based approach and a fuel consumption approach.

CALCULATION METHODOLOGY:
1. *Calculate emissions using a distance-based approach.* CH_4 and N_2O emissions are estimated using the default distance-based approach. CH_4 and N_2O emissions are calculated using emission factors obtained from Table A-8, for "Heavy Duty Diesel Vehicles".

$$E_{CH_4} = \left(\frac{1{,}000{,}000 \text{ miles}}{\text{year}} \times \frac{6.44\times10^{-9} \text{ tonne}}{\text{mile}}\right) + \left(\frac{1{,}500 \text{ cold starts}}{\text{year}} \times \frac{-1.10\times10^{-8} \text{ tonne}}{\text{start}}\right)$$

$$\underline{E_{CH_4} = 0.00642 \text{ tonne } CH_4/\text{yr}}$$

$$E_{N_2O} = \left(\frac{1{,}000{,}000 \text{ miles}}{\text{year}} \times \frac{4.83\times10^{-9} \text{ tonne}}{\text{mile}}\right) + \left(\frac{1{,}500 \text{ cold starts}}{\text{year}} \times \frac{-2.00\times10^{-9} \text{ tonne}}{\text{start}}\right)$$

$$\underline{E_{N_2O} = 0.00483 \text{ tonne } N_2O/\text{yr}}$$

2. *Calculate emissions using a fuel consumption approach.* Emissions were calculated using a fuel consumed basis in Exhibit 4.12. The CH_4 and N_2O emissions were calculated to be:

$$E_{CH_4} = \frac{113{,}636 \text{ gal}}{\text{yr}} \times \frac{4.2 \times 10^{-4} \text{ tonne } CH_4}{1000 \text{ gal}}$$

$$E_{CH_4} = 0.048 \text{ tonnes } CH_4/\text{yr}$$

$$E_{N_2O} = \frac{113{,}636 \text{ gal}}{\text{yr}} \times \frac{5.7 \times 10^{-4} \text{ tonne } CH_4}{1000 \text{ gal}}$$

$$E_{N_2O} = 0.064 \text{ tonnes } N_2O/\text{yr}$$

A.3.2 Marine Vessels

An alternate method for calculating emissions from marine vessels is to use operational data instead of fuel consumed. Emissions can be calculated using the following equation:

$$E = AH \times kW \times LF \times EF \times CF$$

(Equation A-3)

where

E = vessel emissions (tonnes/yr) ;
AH = annual hours per mode of operation (at sea, maneuvering) (hours);
kW = average total vessel kW (kW);
LF = engine load factor, for specified mode of operation (fraction);
EF = emission factor (g/kWh); and
CF = conversion Factor (tonne/10^6 g).

Table A-15 provides default engine load factors and emission factors for marine vessels, based on operational mode.

Table A–15. Default Operational Based Emission Factors for Marine Vessels

Vessel Type	Mode	Load Factor	Emission Factors, Original Units (g/kWh)			Emission Factors, Converted Units (tonne/kWh)		
			CO_2	CH_4	N_2O	CO_2	CH_4	N_2O
Vessel Lightening								
Oil tankers	Maneuvering	0.10	776.81	0.012	0.031	7.77E-04	1.20E-08	3.10E-08
Escort vessels	Maneuvering	0.10	776.81	0.008	0.031	7.77E-04	8.00E-09	3.10E-08
	At sea	0.80	776.81	0.006	0.031	7.77E-04	6.00E-09	3.10E-08
Louisiana Offshore Oil Port (LOOP)								
Tankers	At sea	0.55	776.81	0.006	0.031	7.77E-04	6.00E-09	3.10E-08
	Maneuvering	0.10	776.81	0.012	0.031	7.77E-04	1.20E-08	3.10E-08
Support vessels	Maneuvering	0.25	1044.4	0.008	0.031	1.04E-03	8.00E-09	3.10E-08
LOOP generator	At sea	0.50	1044.83	0.006	0.031	1.04E-03	6.00E-09	3.10E-08
LOOP pumps	At sea	0.10	1044.83	0.006	0.031	1.04E-03	6.00E-09	3.10E-08
Pipelaying Operations								
Pipelaying	Maneuvering	0.75	1044.83	0.008	0.031	1.04E-03	8.00E-09	3.10E-08
Drilling Rigs								
Drill ship equipment	At sea	0.75	776.81	0.006	0.031	7.77E-04	6.00E-09	3.10E-08
Jack-up equipment	At sea	0.75	776.81	0.006	0.031	7.77E-04	6.00E-09	3.10E-08
Semisubmersible equipment	At sea	0.75	776.81	0.006	0.031	7.77E-04	6.00E-09	3.10E-08
Submersible equipment	At sea	0.75	776.81	0.006	0.031	7.77E-04	6.00E-09	3.10E-08
Emergency equipment[a]	At sea	0.75	776.81	0.006	0.031	7.77E-04	6.00E-09	3.10E-08
Drilling propulsion (relocation)	At sea	0.75	776.81	0.006	0.031	7.77E-04	6.00E-09	3.10E-08
Semisubmersible Propulsion (relocation)	At sea	0.75	776.81	0.006	0.031	7.77E-04	6.00E-09	3.10E-08
Drill ship propulsion (maintain position)	Maneuvering	0.15	776.81	0.006	0.031	7.77E-04	6.00E-09	3.10E-08
Semisubmersible Propulsion (maintain position)	Maneuvering	0.15	776.81	0.006	0.031	7.77E-04	6.00E-09	3.10E-08

Table A–15. Default Operational Based Emission Factors for Marine Vessels (concluded)

Vessel Type	Mode	Load Factor	Emission Factors, Original Units (g/kWh)			Emission Factors, Converted Units (tonne/kWh)		
			CO_2	CH_4	N_2O	CO_2	CH_4	N_2O
Survey Vessels								
Survey vessels	At sea	0.90	1044.83	0.006	0.031	1.04E-03	6.00E-09	3.10E-08
Anchor handling[b]	At sea	0.85	652	0.004	0.031	6.52E-04	4.00E-09	3.10E-08
Anchor handling[b]	Maneuvering	0.10	9.6	0.008	0.31	9.60E-06	8.00E-09	3.10E-07
Support Vessels								
Supply/crew boats	At sea	0.85	1043.11	0.006	0.031	1.04E-03	6.00E-09	3.10E-08
	Maneuvering	0.10	1043.11	0.006	0.031	1.04E-03	6.00E-09	3.10E-08
Lift boats	At sea	0.85	1043.11	0.006	0.031	1.04E-03	6.00E-09	3.10E-08
	Maneuvering	0.10	1043.11	0.006	0.031	1.04E-03	6.00E-09	3.10E-08
Tugs/towing boats	At sea	0.85	1043.11	0.006	0.031	6.52E-04	4.00E-09	3.10E-08
	Maneuvering	0.10	1043.11	0.006	0.031	9.60E-06	8.00E-09	3.10E-08
Commercial Marine Vessels								
All except tug boats	At sea	0.80	776.81	0.006	0.031	5.88E-04	6.00E-09	3.10E-08
Tug boats	At sea	0.80	1044.83	0.006	0.031	6.52E-04	4.00E-09	3.10E-08

Footnotes and Source:

a Emergency generators are assumed to operate 500 hours per year based on USEPA guidance.

b All information from DOI, Year 2011 Gulfwide Emissions Inventory Study, Table 6-1, 2014 except for anchor handling which is from DOI, Year 2005 Gulfwide Emissions Inventory Study, Table 6.1.

Exhibit A.3 provides an illustration of how to calculate emissions from marine vessels using an operational basis.

EXHIBIT A.3: Sample Operational Basis Calculation for Combustion Emissions from Marine Vessels

INPUT DATA:
A fleet of 17 diesel-powered tankers operated 90 percent of the year at sea. The fuel consumption and Gross Registered Tonnage for each ship is unknown. The vessels have an average engine rating of 9,400 kW with an average of 2,000 kW auxiliary power. Calculate the CO_2, CH_4, and N_2O emissions from the fleet using an operational basis. Compare the results to the emissions calculated in Exhibit 4.13 (using a fuel consumption basis).

CALCULATION METHODOLOGY:
1. *Calculate fleet emissions using an operational basis*. Emissions are estimated using the operational-based approach load and emission factors provided in Table A-15 (for "*Commercial Marine Vessels*". Assume a tanker). Emissions are calculated using Equation A-3.

$$E_{CO_2} = 17\text{ ships}\times 0.9\times\frac{365\text{ days}}{\text{yr}}\times\frac{24\text{ h}}{\text{day}}\times\frac{11{,}400\text{ kW}}{\text{ship}}\times 0.80\times\frac{776.81\text{ g}}{\text{kWh}}\times\frac{\text{kg}}{1{,}000\text{ g}}\times\frac{\text{tonne}}{1{,}000\text{ kg}}$$

$$E_{CO_2} = 949{,}522\text{ tonnes }CO_2/\text{yr}$$

$$E_{CH_4} = 17\text{ ships}\times 0.9\times\frac{365\text{ days}}{\text{yr}}\times\frac{24\text{ h}}{\text{day}}\times\frac{11{,}400\text{ kW}}{\text{ship}}\times 0.80\times\frac{0.006\text{ g}}{\text{kWh}}\times\frac{\text{kg}}{1{,}000\text{ g}}\times\frac{\text{tonne}}{1{,}000\text{ kg}}$$

$$E_{CH_4} = 7.3\text{ tonnes }CH_4/\text{yr}$$

$$E_{N_2O} = 17\text{ ships}\times 0.9\times\frac{365\text{ days}}{\text{yr}}\times\frac{24\text{ h}}{\text{day}}\times\frac{11{,}400\text{ kW}}{\text{ship}}\times 0.80\times\frac{0.031\text{ g}}{\text{kWh}}\times\frac{\text{kg}}{1{,}000\text{ g}}\times\frac{\text{tonne}}{1{,}000\text{ kg}}$$

$$E_{N_2O} = 37.9\text{ tonnes }N_2O/\text{yr}$$

2. Compare the operational basis emissions to the fuel consumption basis emissions. For comparison purposes, emissions calculated using the fuel consumed basis were calculated (in Exhibit 4.13) to be:

EXHIBIT A.3: Sample Operational Basis Calculation for Combustion Emissions from Marine Vessels, continued

$$E_{CO_2} = \frac{1.07 \times 10^{16}\ \mathrm{J}}{\mathrm{yr}} \times \frac{69.4\ \mathrm{tonne}\ CO_2}{10^{12}\ \mathrm{J}}$$

$$E_{CO_2} = 742{,}580\ \mathrm{tonnes}\ CO_2/\mathrm{yr}$$

$$E_{CH_4} = \frac{275{,}498\ \mathrm{m}^3}{\mathrm{yr}} \times \frac{2.5 \times 10^{-4}\ \mathrm{tonne}\ CH_4}{\mathrm{m}^3}$$

$$E_{CH_4} = 68.9\ \mathrm{tonnes}\ CH_4/\mathrm{yr}$$

$$E_{N_2O} = \frac{275{,}498\ \mathrm{m}^3}{\mathrm{yr}} \times \frac{7.2 \times 10^{-5}\ \mathrm{tonne}\ CH_4}{\mathrm{m}^3}$$

$$E_{N_2O} = 19.8\ \mathrm{tonnes}\ N_2O/\mathrm{yr}$$

A.4 References

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Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Natural Gas and Oil Industry

Appendix B – Additional Venting Calculation Information

November 2021

Table of Contents

List of Tables

List of Figures

B. ADDITIONAL VENTING CALCULATION INFORMATION

This section presents supplemental information for the vented emission calculation methodologies presented in Section 6.

B.1 Derivation of Asphalt Blowing Emission Factors

The asphalt blowing CH_4 emission factors provided in Section 6.11.4 were derived from asphalt blowing exhaust composition data presented in an *Oil & Gas Journal* article (Dimpfl, 1980). Because the asphalt blowing emission factor presented in AP-42 is assumed to be on an air-free basis, the composition is also converted to an air-free basis. Both the original and adjusted samples are presented in Table B-1, along with the molecular weight of each compound:

Table B–1. Default Asphalt Blowing Exhaust Composition

Substance	Industrial Air Blowing Flux, Mole % [a]	Adjusted Industrial Air Blowing Flux, Mole% [b]	Molecular Weight	Air Free Basis, Mol % [c]
H_2	1.20%	1.20%	2.02	52.2%
H_2S	0.10%	0.10%	34.08	4.3%
N and Ar	81.2%	81.25%	28.01	--
O_2	16.4%	16.45%	32.00	--
CO	0.10%	0.10%	28.01	4.3%
CO_2	0.20%	0.20%	44.01	8.7%
CH_4	0.30%	0.30%	16.04	13.0%
C_2	0.10%	0.10%	30.07	4.3%
C_3	0.10%	0.10%	44.10	4.3%
C_4	0.10%	0.10%	58.12	4.3%
C_5+	0.10%	0.10%	72.15	4.3%
Total	99.9%	100%	--	100%

Footnotes and Sources:

[a] Dimpfl, "Study Gives Insight Into Asphalt Tank Explosions", *Oil and Gas Journal*, December 1980.

[b] The Dimpfl results accounted for only 99.9% of the speciation; this column presents the speciation data, adjusted to 100%. speciation.

[c] Derived from Dimpfl. Also reported in ARPEL, *Atmospheric Emissions Inventories Methodologies in the Petroleum Industry*, Table 6.24, 1998.

The exhaust emission rate is typically on a mass basis. Since the exhaust analysis is on a molar basis, the exhaust concentration must be converted to a mass basis. First, the exhaust gas molecular weight of the mixture ($MW_{Mixture}$) must be estimated. Equation 3-8 is used to estimate the gas molecular weight of the air-free mixture.

$$MW_{Mixture} = \frac{1}{100} \times \sum_{i=1}^{\#\,compounds} \left(Mole\%_i \times MW_i\right) \qquad \text{(Equation 3-8)}$$

$$MW_{Mixture} = \frac{1}{100} \times \begin{bmatrix} (52.2\times 2.02)+(4.3\times 34.08)+(4.3\times 28.01)+ \\ (8.7\times 44.01)+(13.0\times 16.04)+(4.3\times 30.07) \\ +(4.3\times 44.10)+(4.3\times 58.12)+(4.3\times 72.15) \end{bmatrix}$$

$$\underline{MW_{Mixture} = 18.56}$$

Next, the weight percent of CH_4 is estimated using Equation 3-7 and rearranged in terms of the weight percent ($Wt\%_i$).

$$Mole\%_i = Wt\%_i \times \frac{MW_{Mixture}}{MW_i} \Rightarrow Wt\%_i = Mole\%_i \times \frac{MW_i}{MW_{Mixture}}$$

$$Wt\%_{CH_4} = \frac{13.0}{100} \times \frac{16.04}{18.56}$$

$$\underline{Wt\%_{CH_4} = 11.27\%}$$

$$Wt\%_{CO_2} = \frac{8.7}{100} \times \frac{44.01}{18.56}$$

$$\underline{Wt\%_{CO_2} = 20.62\%}$$

Finally CO_2 and CH_4 emission factors are calculated, using the density of asphalt (taken from Table 3-8), the AP-42 emission factor for blown asphalt (provided in Section 6.11.4), and the weight percent CH_4 (calculated above). The derivation is shown below, for common U.S. units:

$$EF_{CO_2} = \text{bbl asphalt blown} \times \frac{42\text{ gal}}{\text{bbl}} \times \frac{8.61\text{ lb asphalt}}{\text{gal asphalt}} \times \frac{\text{tonne}}{2204.62\text{ lb}} \times \frac{0.03\text{ tonne exhaust}}{\text{tonne asphalt blown}}$$

$$\times \frac{20.62\text{ tonne CO}_2}{100\text{ tonne exhaust}}$$

$$\underline{EF_{CO_2} = \frac{1.01\text{E-03 tonne CO}_2}{\text{bbl asphalt blown}}}$$

$$EF_{CO_2} = \text{ton asphalt blown} \times \frac{2000\text{ lb}}{\text{ton}} \times \frac{\text{tonne}}{2204.62\text{ lb}} \times \frac{0.03\text{ tonne exhaust}}{\text{tonne asphalt blown}} \times \frac{20.62\text{ tonne CO}_2}{100\text{ tonne exhaust}}$$

$$\underline{EF_{CO_2} = \frac{5.61\text{E-03 tonne CO}_2}{\text{ton asphalt blown}}}$$

$$EF_{CH_4} = \text{bbl asphalt blown} \times \frac{42\text{ gal}}{\text{bbl}} \times \frac{8.61\text{ lb asphalt}}{\text{gal asphalt}} \times \frac{\text{tonne}}{2204.62\text{ lb}} \times \frac{0.03\text{ tonne exhaust}}{\text{tonne asphalt blown}}$$

$$\times \frac{11.27\text{ tonne CH}_4}{100\text{ tonne exhaust}}$$

$$\underline{EF_{CH_4} = \frac{5.55\text{E-04 tonne CH}_4}{\text{bbl asphalt blown}}}$$

$$EF_{CH_4} = \text{ton asphalt blown} \times \frac{2000\text{ lb}}{\text{ton}} \times \frac{\text{tonne}}{2204.62\text{ lb}} \times \frac{0.03\text{ tonne exhaust}}{\text{tonne asphalt blown}} \times \frac{11.27\text{ tonne CH}_4}{100\text{ tonne exhaust}}$$

$$\underline{EF_{CH_4} = \frac{3.07\text{E-03 tonne CH}_4}{\text{ton asphalt blown}}}$$

B.2 Catalytic Cracking Regenerator “K_1, K_2, K_3” Approach

Section 6.11.1 presents two approaches to estimate CO_2 emissions from catalytic cracking regeneration. The first approach, shown in Equation 6-34, is based on the coke burn rate and the coke carbon fraction. The second approach, shown in Equation 6-35, is based on the air blower rate and flue gas CO and CO_2 concentrations.

EPA rule 40 CFR 63, Subpart UUU (40 CFR § 63.1564, Nov. 26, 2018]) and EPA rule 40 CFR 60, Subpart Ja (40 CFR § 60.104a, , Dec. 1, 2015) provide an approach to estimate the coke burn rate using the “K_1, K_2, K_3” approach. This coke burn rate equation is:

$$CC = \left[K_1 \times Q_r \times \left(P_{CO_2} + P_{CO}\right)\right] + \left(K_2 \times Q_a\right) - \left[K_3 \times Q_r \times \left(\frac{P_{CO}}{2} + P_{CO_2} + P_{O_2}\right)\right] + \left(K_3 \times Q_{oxy} \times P_{O_{xy}}\right) \quad \text{(Equation B-1)}$$

where

CC = coke burn rate in units of mass per year (lb/hr or kg/hr);
K_1, K_2, K_3 = material balance and conversion factors (see units provided in table below);
Q_r = volumetric flow rate of exhaust gas before entering the emission control system, calculated using Equation B-2 (dscf/min or dscm/min);
Q_a = volumetric flow rate of air to regenerator as determined from control room instrumentation (dscf/min or dscm/min);
Q_{Oxy} = volumetric flow rate of O_2-enriched air to regenerator as determined from control room instrumentation (dscf/min or dscm/min);
P_{CO_2} = percent CO_2 concentration in regenerator exhaust, percent by volume (dry basis);
P_{CO} = percent CO concentration in regenerator exhaust, percent by volume (dry basis); when no auxiliary fuel is burned and a continuous CO monitor is not required, assume P_{CO} to be zero;
P_{O2} = percent O_2 concentration in regenerator exhaust, percent by volume (dry basis); and
P_{Oxy} = O_2 concentration in O_2-enriched air stream inlet to regenerator, percent by volume (dry basis).

The coke burn rate material balance conversion factors from 40 CFR 63.1564 (November 2018) are shown below:

Table B–2. Coke Burn Rate Material Balance Conversion Factors

Variable	Variable Purpose	Value	Unit
K_1	Carbon burn term	0.2982 0.0186	(kg min)/(hr dscm %) (lb min)/(hr dscf %)
K_2	Hydrogen burn term from O_2 in Air	2.0880 0.1303	(kg min)/(hr dscm %) (lb min)/(hr dscf %)
K_3	Hydrogen burn equivalent in excess O_2 and carbon oxides	0.0994 0.0062	(kg min)/(hr dscm) (lb min)/(hr dscf)

The volumetric flow rate of exhaust gas before entering the emission control system is calculated using Equation B-2:

$$Q_r = \frac{79 \times Q_a + \left(100\text{-}P_{O_{xy}}\right) \times Q_{oxy}}{100\text{-}P_{CO_2}\text{-}P_{CO}\text{-}P_{O_2}} \quad \text{(Equation B-2)}$$

The coke burned is assumed to proceed completely to CO_2. Based on this assumption and accounting for the conversion of units, the CO_2 emission rate is then calculated from Equation B-3.

$$E_{CO_2} = CC_{Avg} \times CF \times \frac{44 \text{ mass units } CO_2\text{/mole}}{12 \text{ mass units C/mole}} \times T \qquad \text{(Equation B-3)}$$

where

E_{CO_2} = emissions of CO_2 in units of mass (pounds, kg, tonnes) per year;
CC_{Avg} = daily average coke burn rate in units of mass per year;
CF = fraction of carbon in the coke burned;
44 = molecular weight of CO_2;
12 = molecular weight of carbon (coke is assumed to be carbon); and
T = Annual operating time (days/year)

Although the EPA rules include the use of all three "K" terms, CO_2 emissions can be estimated directly from the K_1 term. The first term in Equation B-1 ($[K_1 \text{ x } Q_r \text{ x } (P_{CO2} + P_{CO})]$) is the total carbon content in the coke. With this knowledge, the carbon fraction (CF) can be determined by dividing the total carbon content in the coke by the total coke burned, as shown in Equation B-4.

$$CF = \frac{\left[K_1 \times Q_r \times \left(P_{CO_2} + P_{CO}\right)\right]}{\left[K_1 \times Q_r \times \left(P_{CO_2} + P_{CO}\right)\right] + \left(K_2 \times Q_a\right) - \left[K_3 \times Q_r \times \left(\frac{P_{CO}}{2} + P_{CO_2} + P_{O_2}\right)\right] + \left(K_3 \times Q_{oxy} \times P_{O_{xy}}\right)} \qquad \text{(Equation B-4)}$$

Substituting the CC and CF terms into Equation B-3 results in Equation B-5.

$$\begin{aligned} E_{CO_2} = & \left\{\left[K_1 \times Q_r \times \left(P_{CO_2} + P_{CO}\right)\right] + \left(K_2 \times Q_a\right) - \left[K_3 \times Q_r \times \left(\frac{P_{CO}}{2} + P_{CO_2} + P_{O_2}\right)\right] + \left(K_3 \times Q_{oxy} \times P_{O_{xy}}\right)\right\} \\ & \times \frac{\left[K_1 \times Q_r \times \left(P_{CO_2} + P_{CO}\right)\right]}{\left\{\left[K_1 \times Q_r \times \left(P_{CO_2} + P_{CO}\right)\right] + \left(K_2 \times Q_a\right) - \left[K_3 \times Q_r \times \left(\frac{P_{CO}}{2} + P_{CO_2} + P_{O_2}\right)\right] + \left(K_3 \times Q_{oxy} \times P_{O_{xy}}\right)\right\}} \times \frac{44}{12} \end{aligned} \qquad \text{(Equation B-5)}$$

Which reduces to the equation shown below:

$$E_{CO_2} = \left[K_1 \times Q_r \times \left(P_{CO_2} + P_{CO}\right)\right] \times \frac{44 \text{ mas units } CO_2\text{/mole}}{12 \text{ mass units C/mole}} \times H \qquad \text{(Equation B-6)}$$

where

H = Annual operating time (hrs/yr); 8760 hrs/yr if operating continuously throughout the year.

Therefore, by inspection, the CO_2 emissions can be estimated directly from the K_1 term without introducing the error associated with K_2 and K_3 terms and the coke carbon fraction. Equation B-6 is also shown in Section 6.11.1 (Equation 6-35).

B.3 Derivation of Simplified Tank Flashing Emission Factors

B.3.1 Crude Oil Flashing Losses

A simplified CH_4 emission factor was derived from combining crude oil flashing loss measurement data from two separate measurement programs (Ogle, March 1997/Ogle, May 1997; Picard, 1992). The measurement programs involved gas streams with varying CH_4 contents. In order to combine the measurements, each was converted to a common production segment CH_4 concentration of 78.8% (Shires and Harrison, 1996). The measurement data and conversion calculations are summarized in Table B-3.

Table B–3. Crude Oil Tank Flashing Loss Emission Factor Development

Measurement	Oil Fill Rate, bbl/day	CH_4 Emissions, scf/hr [a]	Separator Mol % CH_4	CH_4 EF, scf/bbl	Normalized CH_4 EF, scf/bbl/sep-% CH_4
Canadian Measurements [b]					
1	34.6	4.98	75.91	3.45	0.045
2	69.2	128	81.78	44.5	0.544
3	2,717	5.32	69.99	0.05	0.001
4	34.6	9.32	75.91	6.46	0.085
5	1,413	376	88.16	6.38	0.072
Canadian Average			*78.35*	*12.16*	*0.15*
API Measurements [c]					
1	188	179	57.91	22.8	0.394
2	1,600	573	24.81	8.59	0.346
3	438	19.7	49.61	1.08	0.022
4	259	35.5	80.63	3.29	0.041
5	451	56.9	58.00	3.03	0.052
6	12	73.0	No Data – assume average of 54.19	146	2.69
7	60	371		148	2.74
API Average			*54.19*	*47.6*	*0.90*
Combined Average [d,e]				**32.84±106%**	**0.586±109%**
Corrected Emission Factor, scf CH_4/bbl [d,e]				**46.20**	**±110%**
Corrected Emission Factor, lb CH_4/bbl [d,e]				**1.954**	**±110%**
Corrected Emission Factor, tonnes CH_4/bbl [d,e]				**8.86E-04**	**±110%**
Corrected Emission Factor, tonnes CH_4/m^3 oil [d,e]				**5.57E-03**	**±110%**

Footnotes and Sources:

[a] Corrected to 60°F and 1 atm.

[b] Source: Picard, D. J., B. D. Ross, and D. W. H. Koon. *A Detailed Inventory of CH_4 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.

Footnotes and Sources for Table B-3 Continued

[c] 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 (emission and production rates) and 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 (separator CH_4 concentration).

[d] Uncertainty based on a 95% confidence interval.

[e] Corrected to average CH_4 concentration for natural gas industry production operations of 78.8%. Source for 78.8% CH_4 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 U.S. Environmental Protection Agency, June 1996.

B.3.2 Condensate Flashing Losses

A simplified CH_4 emission factor was derived for condensate flashing losses using a measurement program conducted in east Texas for the Houston Advanced Research Center (Hendler et al., 2006). Condensate tanks were distinguished from crude oil tanks in the measurements program based on how the well sites were classified in the Texas Railroad Commission online database. The measurement program presented flashing loss emission rates, compositions, and liquid production rates. From these data, an average condensate flashing loss emission factor was developed based on averaging the data as summarized in Table B-4.

Table B–4. Condensate Tank Flashing Loss Emission Factor Development [a]

HARC Study Tank Battery Number	Data Point Number	Condensate Production Rate, bbl/day	Tank Vent Rate, scf/day	Tank Vent MWT, lb/lbmole	Total Gas Vent Mass Rate, lb/day [b]	Vent Gas CH_4 Content, Wt. %	CH_4 Emission Rate, lb/day	CH_4 Emission Factor, lb/bbl
2	1	105	11,406	27.3	821.3	39.71	325.8	3.103
3	2	87	12,642	33.4	1,113.8	26.30	292.7	3.364
4	3	120	1,807	34.3	163.4	22.07	36.0	0.300
5	4	100	863	42.2	96.2	12.06	11.6	0.116
6	5	130	6,200	36.4	594.6	19.27	114.5	0.881
13	6	2	793	46.4	97.0	8.53	8.3	4.133
14	7	4	2,744	30.5	220.7	31.52	69.5	17.373
15	8	5	584	47.6	73.4	6.52	4.8	0.956
16	9	2	1,084	50.0	143.1	5.83	8.3	4.167
17	10	2	4,594	36.6	443.2	23.26	103.0	51.501
18	11	10	1,015	38.9	104.2	20.24	21.1	2.108
19	12	2	291	44.3	34.0	13.81	4.7	2.345
20	13	10	3,113	46.4	380.8	7.91	30.1	3.010
23	14	27	1,358	51.9	185.9	10.28	19.1	0.707
24	15	1	53	43.0	6.0	12.35	0.7	0.742
25	16	1	926	89.0	217.4	0.09	0.2	0.200
27	17	2	235	54.0	33.5	6.53	2.2	1.093
28	18	30	2,846	30.2	226.9	31.93	72.4	2.413
29	19	61	21,601	43.5	2,476.4	10.04	248.4	4.072
30	20	15	1,639	34.2	147.9	23.10	34.1	2.277
32	21	142	77,319	50.6	10,312.6	2.15	221.9	1.562
26	22	1	9,210	56.2	1,365.7	3.93	53.6	Excluded [c]
Average, lb CH_4/bbl [d]:							**5.068**	**±101%**
Average converted to tonnes CH_4/bbl [d]:							**0.00230**	**±101%**
Average converted to tonnes CH_4/m^3 condensate [d]:							**0.0145**	**±101%**

Footnotes and Sources for Table B-4:
[a] Hendler, Albert, Jim Nunn, Joe Lundeen, Ray McKaskle. *VOC Emissions from Oil and Condensate Storage Tanks*, Final Report, prepared for Houston Advanced Research Center (HARC), October 31, 2006 (Cited Tables 3-3 and 3-5).
[b] Corrected to 60°F and 1 atm.
[c] Data point excluded from analysis since the report indicates that the value is an anomaly due to fracking at an adjacent well.
[d] Uncertainty based on a 95% confidence interval.

B.4 Additional Loading, Ballasting, and Transit Loss Methodology

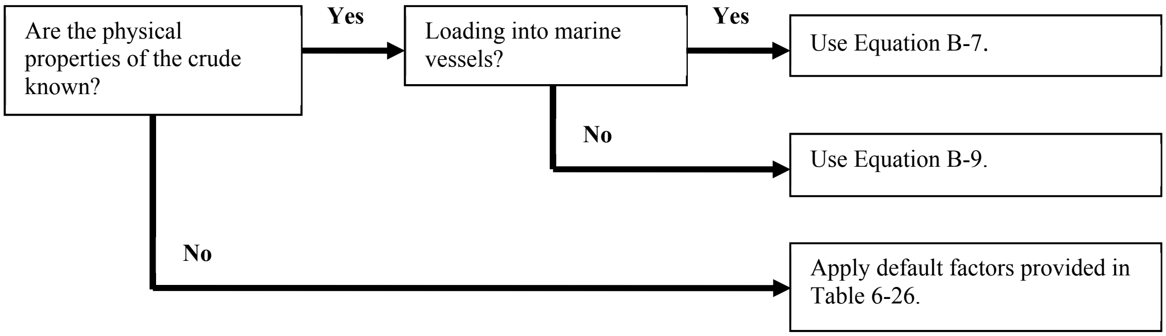
Calculating evaporative emissions associated with loading, ballasting, and transit operations is suggested only for "live" crude oil or if measured CH_4 or CO_2 content data are available for "weathered" crude or other petroleum vapors.[1] Section 6.10 presents the simple calculation approaches for loading, ballasting, and transit loss emissions for crude oil. This section provides more detailed calculation approaches. However, due to the fact that there is typically no CH_4 or CO_2 in most petroleum products nor in "weathered" crude. These methods are useful for estimating CO_2 emissions that result when the evaporative emissions associated with loading, ballasting, and transit operations are sent to a combustion control device, such as a thermal oxidizer or VCU. More information on the CH_4 and CO_2 content of "weathered" crude and other petroleum products is provided in Appendix D.

B.4.1 Loading Loss Emissions

Figures B-1 and B-2 provide guidance for selecting among the available techniques for estimating loading losses. Figure B-1 applies to crude, while Figure B-2 applies to other petroleum fuels. When loading losses are routed to a combustion device, the mass of vapors sent to the combustion device can be estimated using the methodology described in this section. Emissions from the combustion device should be calculated using the methodology described in Section 4.

Options Based on Fuel Type and Available Information

Crude:



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other petroleum liquids is generally considered negligible (EPA, AP-42 Section 5.2, 2008).

Figure B–1. Decision Tree for Crude Loading Losses

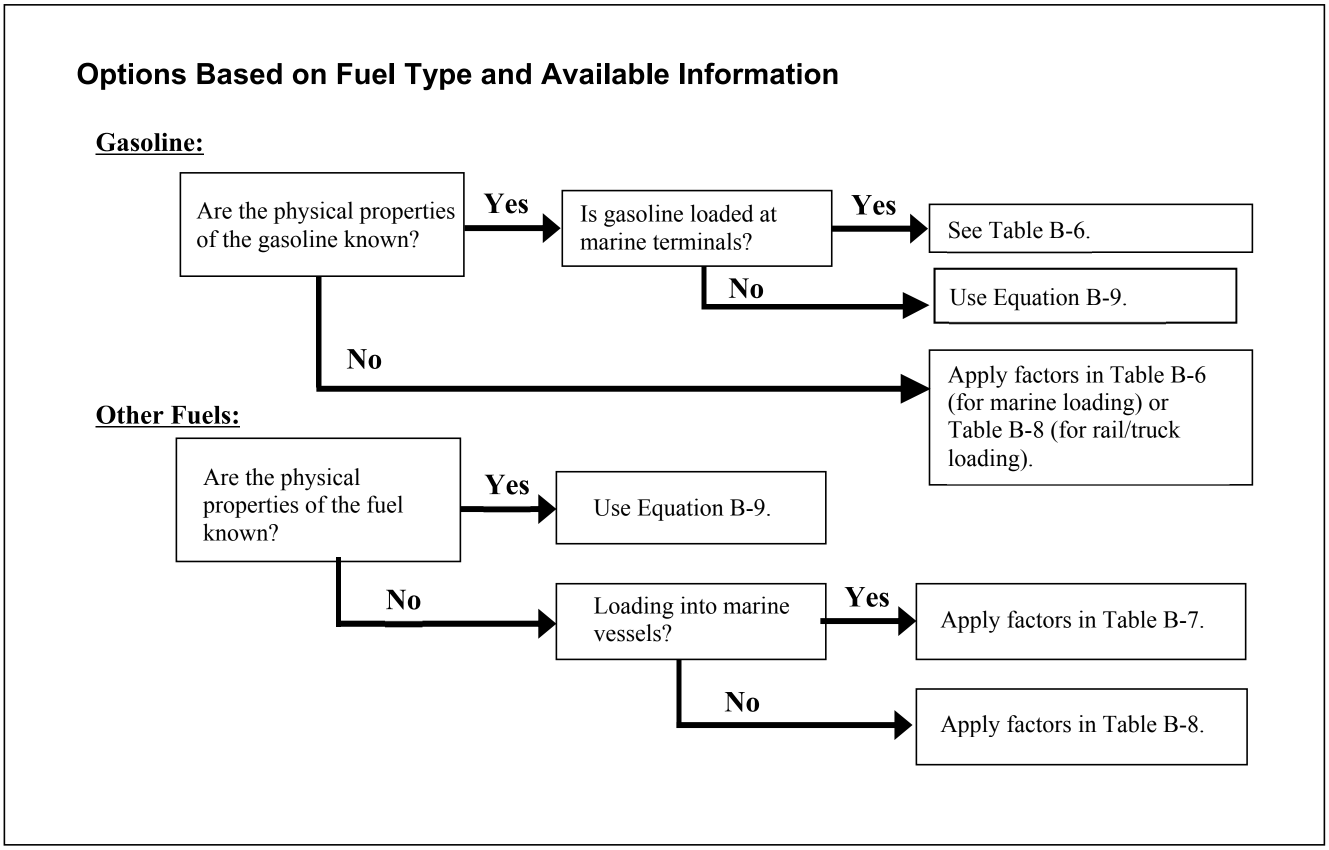

Figure B–2. Decision Tree for Gasoline and Other Liquid Fuel Loading Losses

For crude oil loaded into ships and ocean barges, Equation B-7, below, is applicable (EPA, AP-42, Section 5.2, 2008).

$$C_L = C_A + C_G \qquad \text{(Equation B-7)}$$

where

C_L = total loading loss TOC emission factor, lb/10^3 gallon of crude oil loaded;
C_A = arrival emission factor, from vapors in the empty tank vessel before loading, lb/10^3 gallon loaded (shown in Table B-3); and
C_G = emission factor for emissions generated during loading, lb/10^3 gallon (calculated using Equation B-8).

Equation B-8 provides the calculation for the factor C_G (EPA, AP-42 Section 5.2, Equation 3, 2008).

$$C_G = 1.84 \times (0.44\,P - 0.42) \times \left(\frac{M \times G}{T}\right) \qquad \text{(Equation B-8)}$$

where

P = true vapor pressure of loaded crude oil, psia;
M = molecular weight of the vapors, lb/lb-mole;
G = vapor growth factor = 1.02, dimensionless; and
T = temperature of the vapors, °R (°R = °F + 459.7)

The arrival factor, C_A, in the expression above is presented in Table B-5 below.

Table B–5. Average Arrival TOC Emission Factor, C_A, for the Crude Oil Marine Vessel Loading Emission Factor Equation

Ship/Ocean Barge Tank Condition	Previous Cargo [b]	Arrival Emission Factor, C_A		
		Original Units [a,c]	Converted Units	
		lb TOC/10^3 gallon	tonnes TOC/gal	tonnes TOC/m^3
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

Footnotes and Sources:
[a] EPA, AP-42, Section 5.2, June 2008.
[b] The factors shown are for TOCs. AP-42 reports that the VOC comprises 55-100% of the TOC, with a typical value of 85%. Thus, a simplifying assumption for the CH_4 content of the TOC is 15% in the absence of site-specific data, recognizing that this likely overestimates the CH_4 emissions.
[c] "Volatile" cargo refers to those cargoes with a vapor pressure greater than 1.5 psia.

Physical properties such as the true vapor pressure of the fuel (P), Reid Vapor Pressure (RVP), and the molecular weight of the vapors (M) are required inputs for this approach. Several references provide this information, including *Perry's Chemical Engineering Handbook* (Perry, 1984) and the *CRC Handbook of Chemistry and Physics* (CRC Press, 1984). Table B-6 provides these properties for some select petroleum liquids based on the average ambient temperature of the facility (EPA, AP-42, Section 7.1, 2020).

Average temperature information for a specific location can be found at a number of Internet sites, such as[2]:

http://www.worldclimate.com/
http://www.weatherbase.com/
http://www.ncdc.noaa.gov/oa/ncdc.html

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[2] Accessed October 27, 2021.

Table B–6. Properties of Select Petroleum Liquids [a]

Petroleum Liquid [b]	Vapor Molecular Weight at 60°F, (lb/lbmole)	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	7.1	1.8	2.3	2.8	3.4	4.0	4.8	5.7
Distillate fuel oil No. 2	130	7.1	0.0031	0.0045	0.0065	0.009	0.012	0.016	0.022
Gasoline RVP 7	68	5.6	2.3	2.9	3.5	4.3	5.2	6.2	7.4
Gasoline RVP 10	66	5.6	3.4	4.2	5.2	6.2	7.4	8.8	10.5
Gasoline RVP 13	62	5.6	4.7	5.7	7.0	8.3	9.9	11.7	13.8
Jet kerosene	130	7.0	0.0041	0.006	0.008	0.011	0.015	0.021	0.029
Jet naphtha (JP-4)	80	6.4	0.8	1	1.3	1.6	1.9	2.4	2.7
Residual oil No. 6	190	7.9	0.00002	0.00003	0.00004	0.00006	0.00009	0.000013	0.000019

Petroleum Liquid [b]	Vapor Molecular Weight at 60°F, (lb/lbmole)	Liquid Density 60°F, (kg/m^3)	True Vapor Pressure (psi)						
			4.4°C	10.0°C	15.6°C	21.1°C	26.7°C	32.2°C	37.8°C
Crude oil RVP 5	50	851	12.4	15.9	19.3	23.4	27.6	33.1	39.3
Distillate fuel oil No. 2	130	851	0.021	0.031	0.045	0.062	0.083	0.11	0.15
Gasoline RVP 7	68	671	15.9	20.0	24.1	29.6	35.9	42.7	51.0
Gasoline RVP 10	66	671	23.4	29.0	35.9	42.7	51.0	60.7	72.4
Gasoline RVP 13	62	671	32.4	39.3	47.6	57.2	68.3	80.7	95.1
Jet kerosene	130	839	0.028	0.041	0.059	0.076	0.10	0.14	0.20
Jet naphtha (JP-4)	80	767	5.5	6.9	9.0	11.0	13.1	16.5	18.6
Residual oil No. 6	190	947	0.000138	0.000207	0.000276	0.000414	0.000621	0.000896	0.000131

Footnotes and Sources:

[a] EPA, AP-42, Table 7.1-2, March 2020.

[b] Properties of additional petroleum liquids and petrochemicals are available in AP-42, Section 7.1, March 2020.

When estimating evaporative CH_4 (or CO_2, if present) emissions from loading operations, the fuel CH_4 (or CO_2) content is required to convert from the TOC emission factors provided in this section. For crude oil, AP-42 reports that the VOC comprises 55-100 wt% of the TOC, with a typical value of 85%. Thus, a simplifying assumption for the CH_4 content of the "live" crude TOC is 15 wt% in the absence of site-specific data. This assumption overestimates emissions because the non-VOC portion of the TOC includes both CH_4 and ethane (C_2H_6). Based on composition data presented in Appendix D, this wt% CH_4 would not be applicable to "weathered" crude or refined petroleum products. However, evaporative emissions from loading operations may be combusted in the control device, which would convert the hydrocarbons to CO_2.

Exhibit B.6 illustrates the use of Equation B-7 for estimating evaporative CH_4 emissions from marine vessel loading of "live" crude oil.

EXHIBIT B.6: Sample Calculation for Estimating Crude Oil Marine Loading Loss CH_4 Emissions Using Equations B-7 and B-8

INPUT DATA:
50,000 bbl/yr of "live" crude oil with a Reid Vapor Pressure (RVP) of 5 is loaded into ships at a marine terminal. The ships are not cleaned prior to loading. The previous cargo in the ships was also crude oil (RVP 5). The average ambient temperature at the facility is 70°F (529.7°R) based on average annual meteorological data. Calculate the CH_4 emissions.

CALCULATION METHODOLOGY:
The crude oil molecular weight and vapor pressure are estimated using data provided in Table B-6 for crude oil with an RVP of 5 psi. Using Equation B-8, the "generated emission factor" or C_G is calculated as:

$$C_G = 1.84 \times [(0.44 \times 3.4) - 0.42] \times \left(\frac{50 \times 1.02}{529.7}\right)$$

$$C_G = 0.19 \text{ lb TOC}/10^3 \text{gal crude}$$

Next, the "arrival" emission factor, C_A, is read from Table B-5. Because the crude (previous cargo) has a vapor pressure greater than 1.5 psia, it is classified as "volatile." Thus, for "uncleaned" ships, Table B-5 gives a C_A factor of 0.86 lb TOC/10^3 gallons of crude loaded. With the factors C_A and C_G now defined, the total loading loss factor, C_L, is estimated using Equation B-7:

$$C_L = (0.86 \text{ lb TOC}/10^3 \text{ gal}) + (0.19 \text{ lb TOC}/10^3 \text{ gal})$$

$$C_L = 1.05 \text{ lb TOC}/10^3 \text{ gal crude loaded}$$

EXHIBIT B.6: Sample Calculation for Estimating Crude Oil Marine Loading Loss CH_4 Emissions Using Equations B-7 and B-8, continued

The last step in the calculation is to estimate the loading loss emissions by multiplying the loading loss emission factor, C_L, by the annual crude throughput loaded into the ships. Also, the TOC must be multiplied by the CH_4 content of the vapors to obtain the CH_4 emissions. Because a specific CH_4 content is not available, 15% by weight is assumed, per Table B-5. Thus, the CH_4 emissions from the "live" crude oil ship loading are:

$$E_{CH_4} = \frac{1.05 \text{ lb TOC}}{10^3 \text{gal}} \times \frac{42 \text{ gal}}{\text{bbl}} \times \frac{50{,}000 \text{ bbl}}{\text{yr}} \times \frac{15 \text{ lb } CH_4}{100 \text{ lb TOC}} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CH_4} = 0.15 \text{ tonnes } CH_4/\text{yr}}$$

A general equation is provided for estimating loading losses for all other petroleum liquids, including crude and gasoline, into tank trucks and rail cars (EPA, AP-42 Section 5.2, 2008). This equation also applies to marine vessel loading for petroleum liquids other than crude and gasoline. AP-42 provides an accuracy estimate of ±30% associated with this approach.

$$L_L = 12.46 \frac{S \times P \times M}{T} \qquad \text{(Equation B-9)}$$

where

L_L = loading loss emission factor, lb/10^3 gallon of liquid loaded; this factor is for TOC;
S = saturation factor (shown in Table B-7);
P = true vapor pressure of liquid loaded, psia;
M = molecular weight of the vapors, lb/lb-mole; and
T = temperature of bulk liquid loaded, °R (°R = °F + 459.7).

The calculated TOC emissions are then used to estimate CO_2 emissions resulting from routing the loading loss vapors to a combustion control device, as shown in Equation B-10.

$$CO_2 \text{ Emissions (tonnes)} = \text{Volume loaded (gal)} \times \frac{\text{lb TOC}}{10^3 \text{ gal}} \times \frac{\text{lb C}}{\text{lb TOC}} \times \text{EFF} \times \frac{44 \text{ lb } CO_2 / \text{lbmole } CO_2}{12 \text{ lb C / lbmole C}} \times \frac{\text{tonne } CO_2}{2204.62 \text{ lb}} \qquad \text{(Equation B-10)}$$

or

$$\text{CO}_2 \text{ Emissions (tonnes)} = \frac{\text{tonnes TOC}}{\text{yr}} \times \frac{\text{tonne C}}{\text{tonne TOC}} \times \text{EFF} \times \frac{44 \text{ lb CO}_2 \text{ / lbmole CO}_2}{12 \text{ lb C / lbmole C}} \times \frac{\text{tonne CO}_2}{2204.62 \text{ lb}} \quad \text{(Equation B-11)}$$

where

EFF = efficiency of the control device in converting hydrocarbon to CO_2. If site data are not available, a 98% combustion efficiency can be assumed.

Physical properties for select petroleum fuels are provided above in Table B-6. Table B-7 presents saturation factors used in Equation B-9, according to cargo carrier type and mode of operation.

Table B–7. Saturation, S, Factors for Estimating Loading Losses

Cargo Carrier Type	Mode of Operation	S Factor [a]
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
Marine vessels [b]	Submerged loading: ships	0.2
	Submerged loading: barges	0.5

Footnotes and Sources:

[a] EPA AP-42, Section 5.2, June 2008.

[a] Marine vessel saturation factor shown above is not applicable for gasoline and crude oil loading. For marine loading of crude oil, use Equations B-7 and B-8, and Table B-3. For marine loading of gasoline, refer to Table B-5.

As mentioned earlier, "weathered" crude and other petroleum liquids typically contain no CH_4 (or CO_2); for this reason, no evaporative CH_4 (and CO_2) emissions result from the loading of these liquids.

A sample calculation illustrating the use of Equation B-9 for estimating controlled emissions from "weathered" crude oil tank truck loading follows in Exhibit B.8.

EXHIBIT B.8: Sample Calculation for Estimating Loading Loss CH_4 Emissions Using General Equation Approach

INPUT DATA:
100 bbl/day of "weathered" crude oil (RVP 5) is loaded into tank trucks from an oil tank battery. The tank truck loading type is submerged and dedicated normal service of the truck is utilized. Vapors from the loading operation are sent to a thermal oxidizer, rated at 99.95% destruction efficiency. The average ambient temperature at this facility is 70 °F. Calculate the CO_2 emissions. (Note that because "weathered" crude oil does not contain CH_4, there are no residual CH_4 emissions from combustion of the loading vapors.)

EXHIBIT B.8: Sample Calculation for Estimating Loading Loss CH_4 Emissions Using General Equation Approach, continued

CALCULATION METHODOLOGY:
To use Equation B-9, physical properties of the crude oil and the saturation factor, S, must be determined. Table B-6 is used to determine the physical properties of the crude oil based on the average ambient temperature. The saturation factor, S, is taken from Table B-7 for submerged loading, dedicated normal service of the tank truck.

Using Equation B-9, the TOC loading loss emission factor is calculated as:

$$L_L = 12.46 \frac{(0.6)\times(3.4)\times(50)}{529.7}$$

$$L_L = 2.40 \text{ lb TOC}/10^3\text{gal}$$

The loading loss emissions are calculated by multiplying the loading loss emission factor by the throughput.

$$E_{TOC} = \frac{2.40 \text{ lb TOC}}{10^3\text{gal}} \times \frac{42 \text{ gal}}{\text{bbl}} \times \frac{100 \text{ bbl}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$E_{TOC} = 1.67 \text{ tonnes TOC/yr}$$

Carbon dioxide emissions are then calculated by converting the mass of TOC to a mass of carbon, as shown in Equation B-11. Because the carbon content of the “weathered” crude oil vapors is not available, the carbon content of crude oil given in Table 3-8 (for liquid crude oil) is used instead. Note that using the carbon content of the liquid fuel instead of the carbon content of the vapor phase is a simplifying assumption. In reality, the carbon content of vapor phase crude oil will be less than the carbon content of liquid crude oil, due to the fact that vapors contain lighter hydrocarbons, which are more able to volatilize. Carbon dioxide emissions are calculated below.

$$E_{CO_2} = \frac{1.67 \text{ tonnes TOC}}{\text{yr}} \times \frac{0.848 \text{ tonne C}}{\text{tonne TOC}} \times \frac{0.9995 \text{ tonne } CO_2 \text{ formed}}{\text{tonne } CO_2 \text{ combusted}} \times \frac{44.01 \text{ tonne } CO_2}{12.01 \text{ tonne C}}$$

$$\underline{E_{CO_2} = 5.19 \text{ tonnes } CO_2/\text{yr}}$$

In addition to the detailed methods presented above for loading loss emissions, simplified TOC emission factors for loading loss emissions can be found in Table 6-47 (Section 6.10.1) for crude oil loading and in Tables B-8 through B-10 for other petroleum product loading. These simplified loading loss emission factors should be used when specific input data for Equations B-7 through B-9 above are not available.

Table B-8 presents TOC emission factors for gasoline loading into ships and barges (EPA, AP-42 Table 5.2-2, 2008).

Table B-8. TOC Emission Factors for Gasoline Loading at Marine Terminals [a]

Vessel Tank Condition	Previous Cargo [b]	Units		Ships/Ocean Barges [c]	Barges [d]
Uncleaned	Volatile	Original Units	lb TOC/10^3 gal loaded	2.6	3.9
			mg TOC/L loaded	315	465
		Converted Units [e]	tonne TOC/106 gal loaded	1.19	1.76
			tonne TOC/1000m3 loaded	0.315	0.465
Ballasted	Volatile	Original Units	lb TOC/103 gal loaded	1.7	Barges are typically not ballasted
			mg TOC/L loaded	205	
		Converted Units [e]	tonne TOC/10^6 gal loaded	0.776	
			tonne TOC/1000m^3 loaded	0.205	
Cleaned	Volatile	Original Units	lb TOC/10^3 gal loaded	1.5	No data
			mg TOC/L loaded	180	
		Converted Units [e]	tonne TOC/10^6 gal loaded	0.681	No data
			tonne TOC/1000m^3 loaded	0.180	
Gas-freed	Volatile	Original Units	lb TOC/10^3 gal loaded	0.7	No data
			mg TOC/L loaded	85	
		Converted Units [e]	tonne TOC/10^6 gal loaded	0.322	No data
			tonne TOC/1000m^3 loaded	0.085	
Any condition	Non-volatile	Original Units	lb TOC/10^3 gal loaded	0.7	No data
			mg TOC/L loaded	85	
		Converted Units [e]	tonne TOC/10^6 gal loaded	0.322	No data
			tonne TOC/1000m^3 loaded	0.085	
Gas-freed	Any cargo	Original Units	lb TOC/10^3 gal loaded	No data	2.0
			mg TOC/L loaded		245
		Converted Units [e]	tonne TOC/10^6 gal loaded	No data	0.93
			tonne TOC/1000m^3 loaded		0.245
Typical overall situation	Any cargo	Original Units	lb TOC/10^3 gal loaded	1.8	3.4
			mg TOC/L loaded	215	410
		Converted Units [e]	tonne TOC/10^6 gal loaded	0.814	1.55
			tonne TOC/1000m^3 loaded	0.215	0.410

Footnotes and Sources:

[a] EPA, AP-42, Section 5, Table 5.2-2, 2008. The factors shown are for both TOC and VOC because AP-42 reports that the methane and ethane content of the loading emissions is negligible.

[b] "Volatile" cargo refers to those liquids with a vapor pressure greater than 1.5 psia.

[c] AP-42 reports that ocean barges (tank compartment depth of ~40 feet) exhibit emission levels similar to tank ships.

[d] Shallow draft barges (tank compartment depth of 10-12 feet) yield higher emissions than ocean barges.

[e] 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/10^3 gallons.

Table B-9 presents TOC emission factors for marine loading of other petroleum products (EPA, AP-42 Table 5.2-6, 2008).

Table B-9. TOC Emission Factors for Marine Loading of Additional Petroleum Products [a]

Loading Type	Units		Jet Naphtha (JP-4)	Jet Kerosene	Distillate Oil No. 2	Residual Oil No. 6
Ships/ocean barge loading	Original Units	lb TOC/10^3 gal loaded	0.50	0.005	0.005	0.00004
		mg TOC/L loaded	60	0.63	0.55	0.004
	Converted Units [b]	tonne TOC/10^6 gal loaded	0.23	0.0024	0.0021	1.51E-05
		tonne TOC/10^3 m^3 loaded	0.060	0.00063	0.00055	4.00E-06
Barge loading	Original Units	lb TOC/10^3 gal loaded	1.2	0.013	0.012	0.00009
		mg TOC/L loaded	150	1.60	1.40	0.011
	Converted Units [b]	tonne TOC/10^6 gal loaded	0.57	0.0061	0.0053	4.16E-05
		tonne TOC/10^3 m^3 loaded	0.150	0.0016	0.0014	1.10E-05

Footnotes and Sources:

[a] EPA, AP-42, Section 5, Table 5.2-6, 2008. The factors shown are for both TOC and VOC because AP-42 reports that the methane and ethane content of the loading emissions is negligible.

[b] 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/10^3 gallons.

Table B-10 presents simplified TOC emission factors for emissions resulting from rail and tank car loading (EPA, AP-42 Table 5.2-5, 2008).

Table B-10. TOC Emission Factors for Rail/Truck Loading Losses [a]

Loading Type	Units		Gasoline [b]	Jet Naphtha (JP-4)	Jet Kerosene	Distillate Oil No. 2	Residual Oil No. 6
Rail / Truck Loading Submerged Loading - Dedicated normal service	Original Units	lb TOC/10^3 gal loaded	5	1.5	0.016	0.014	0.0001
		mg TOC/L loaded	590	180	1.9	1.7	0.01
	Converted Units [c]	tonne TOC/10^6 gal loaded	2.23	0.68	0.0072	0.0064	3.79E-05
		tonne TOC/10^3 m^3 loaded	0.590	0.180	0.0019	0.0017	1.00E-05
Rail / Truck Loading Submerged Loading - Vapor balance service	Original Units	lb TOC/10^3 gal loaded	8	2.5	--[d]	--[d]	--[d]
		mg TOC/L loaded	980	300	--[d]	--[d]	--[d]
	Converted Units [c]	tonne TOC/10^6 gal loaded	3.71	1.14	--[d]	--[d]	--[d]
		tonne TOC/10^3 m^3 loaded	0.980	0.300	--[d]	--[d]	--[d]
Rail / Truck Loading Splash Loading - Dedicated normal service	Original Units	lb TOC/10^3 gal loaded	12	4	0.04	0.03	0.0003
		mg TOC/L loaded	1,430	430	5	4	0.03
	Converted Units [c]	tonne TOC/10^6 gal loaded	5.41	1.63	0.019	0.015	1.14E-04
		tonne TOC/10^3 m^3 loaded	1.430	0.430	0.0050	0.0040	3.00E-05
Rail / Truck Loading Splash Loading - Vapor balance service	Original Units	lb TOC/10^3 gal loaded	8	2.5	--[d]	--[d]	--[d]
		mg TOC/L loaded	980	300	--[d]	--[d]	--[d]
	Converted Units [c]	tonne TOC/10^6 gal loaded	3.71	1.14	--[d]	--[d]	--[d]

		tonne TOC/10^3 m^3 loaded	0.980	0.300	--[d]	--[d]	--[d]

Footnotes and Sources:

[a] EPA, AP-42, Section 5, Table 5.2-5, June 2008. The emission factors for gasoline are for both TOC and VOC because AP-42 reports that the methane and ethane content of the loading emissions is negligible for these products. The rail/truck loading emission factors were derived using Equation B-5 assuming a liquid temperature of 60°F.

[b] The example gasoline has an RVP of 10 psia.

[c] 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/10^3 gallons.

[d] Not normally used.

A sample calculation illustrating the use of the marine gasoline loading emission factors is presented in Exhibit B.7.

EXHIBIT B.7: Sample Calculation for Estimating Gasoline Marine Loading Loss Vapor Combustion Unit Emissions

INPUT DATA:
50,000 bbl/yr of gasoline (RVP 7) is loaded into ships and ocean barges at a marine terminal. The ships are cleaned prior to loading, and the previous cargo was also gasoline, RVP 7. The average ambient temperature at the terminal is 70°F. The vapors from loading operations are captured and sent to a vapor combustion unit (VCU). The vapor combustion unit does not require a pilot to operate. Calculate the CO_2 emissions.

CALCULATION METHODOLOGY:
To calculate the VCU CO_2 emissions, the mass of the vapors sent to the VCU from the loading operation must be calculated. Loading losses are calculated using an emission factor from Table B-8, for clean ships and ocean barges previously storing volatile gasoline. Based on an average ambient temperature, the gasoline (RVP 7) vapor pressure is 4.3 psia, per Table B-6. Because the vapor pressure is greater than 1.5 psia, the previous cargo is classified as “volatile.” Loading loss emissions are calculated below.

$$E_{TOC} = \frac{0.681 \text{ tonne TOC}}{10^6 \text{ gal}} \times \frac{42 \text{ gal}}{\text{bbl}} \times \frac{50{,}000 \text{ bbl}}{\text{yr}}$$

$$E_{TOC} = 1.43 \text{ tonnes TOC/yr}$$

Carbon dioxide emissions are then calculated by converting the mass of TOC to a mass of carbon, and applying the API *Compendium* default assumption of 100% conversion of carbon to CO_2. Because the carbon content of gasoline vapors is not available for this example, the carbon content of motor gasoline given in Table 3-8 (for liquid gasoline) is used instead.

Note that using the carbon content of liquid fuels instead of the carbon content of vapor phase gasoline is a simplifying assumption. In reality, the carbon content of vapor phase gasoline will be less than the carbon content of liquid gasoline, due to the fact that gasoline vapors contain lighter hydrocarbons, which are more able to volatilize. Carbon dioxide emissions are calculated below.

$$E_{CO_2} = \frac{1.43 \text{ tonnes TOC}}{\text{yr}} \times \frac{0.866 \text{ tonne C}}{\text{tonne TOC}} \times \frac{44.01 \text{ tonne } CO_2}{12.01 \text{ tonne C}}$$

$$\underline{E_{CO_2} = 4.54 \text{ tonnes } CO_2/\text{yr}}$$

B.4.2 Ballasting Emissions

Ballasting operations are used to improve the stability of empty tanker ships after their cargo tanks have been unloaded. After the 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. Figure B-3 illustrates the calculation options available for ballasting emissions based on the petroleum liquid type and other available information.

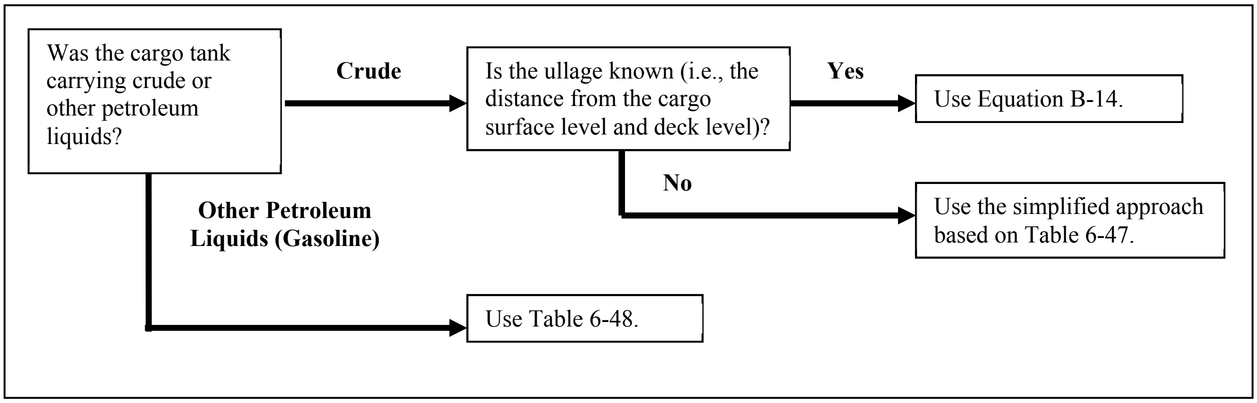

Figure B–3. Decision Tree for Petroleum Liquid Ballasting Emissions

Ballasting emissions from crude oil ships and ocean barges can be estimated using Equation B-12 (EPA, AP-42 Section 5.2, Equation 4, 2008), developed from test data. This equation results in a TOC emission rate that should be converted to CH_4 (or CO_2, if present) emissions based on the CH_4 (or CO_2) content of the vapors. As noted earlier, "weathered" crude and other petroleum products typically do not contain CH_4 (or CO_2).

$$L_B = 0.31 + 0.20 \text{ P} + 0.01 \text{ P } U_A \qquad \text{(Equation B-12)}$$

where

L_B = ballasting TOC emission factor, lb/10^3 gallon of ballast water;

P = true vapor pressure of crude oil unloaded, psia; and
U_A = arrival cargo true ullage, prior to dockside discharge, feet; note: “ullage” refers to the distance between the cargo surface level and the deck level.

The vapor pressure of the discharged crude oil must be known to calculate the ballasting emissions using the equation above. This can be determined from Table B-6 using the average ambient temperature of the facility.

A sample calculation for estimating crude oil ballasting emissions is shown in Exhibit B.9.

EXHIBIT B.9: Sample Calculation for Crude Oil Ballasting Emissions Based on Known Ullage

INPUT DATA:
"Weathered" crude oil (RVP 5) is unloaded from ships at a marine terminal. The annual ballast water throughput is 1 million bbl/year and the average ullage of the arriving ships loaded with crude is 5 feet (distance from deck level to the crude oil surface level). Vapors are sent to a VCU with a destruction efficiency of 99.9%. The average ambient temperature at the facility is 70°F (529.7°R) based on average annual meteorological data. Calculate the CO_2 emissions. (Note that because 'weathered' crude oil does not contain CH_4, there are no residual CH_4 emissions from combustion of the ballasting vapors.)

CALCULATION METHODOLOGY:
Using the average ambient temperature and Table B-6, the crude oil vapor pressure is 3.4 psia at 70°F. The ballasting TOC emission factor is calculated using Equation B-12:

$$L_B = 0.31 + (0.20 \times 3.4 \text{ psia}) + (0.01 \times 3.4 \text{ psia} \times 5 \text{ ft})$$

$$L_B = 1.16 \text{ lb TOC}/10^3 \text{ gal ballast water}$$

The ballasting emissions are obtained by multiplying the ballasting emission factor, L_B, by the annual ballast water throughput loaded into the ships.

$$E_{TOC} = \frac{1.16 \text{ lb TOC}}{10^3 \text{ gal}} \times \frac{42 \text{ gal}}{\text{bbl}} \times \frac{1 \times 10^6 \text{ bbl}}{\text{yr}} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$E_{TOC} = 22.10 \text{ tonnes TOC/yr}$$

Carbon dioxide emissions are then calculated by converting the mass of TOC to a mass of carbon. Because the carbon content of the "weathered" crude oil vapors is not available for this example, the carbon content of crude oil given in Table 3-8 (for liquid crude oil) is used instead. Note that using the carbon content of the liquid fuel instead of the carbon content of the vapor phase is a simplifying assumption. In reality, the carbon content of vapor phase crude oil will be less than the carbon content of liquid crude oil, due to the fact that vapors contain lighter hydrocarbons, which are more able to volatilize. Carbon dioxide emissions are calculated below.

$$E_{CO_2} = \frac{22.10 \text{ tonnes TOC}}{\text{yr}} \times \frac{0.848 \text{ tonne C}}{\text{tonne TOC}} \times \frac{0.999 \text{ tonne } CO_2 \text{ formed}}{\text{tonne } CO_2 \text{ combusted}} \times \frac{44.01 \text{ tonne } CO_2}{12.01 \text{ tonne C}}$$

$$\underline{E_{CO_2} = 68.61 \text{ tonnes } CO_2/\text{yr}}$$

If the cargo ullage is unknown and data are not available to estimate the crude vapor pressure, then average ballasting emission factors can be used to estimate ballasting emissions (EPA, AP-42 Table 5.2-4, 2008). These emission factors are provided in Table 6-48 in Section 6.10.2 (refer to Section 6.10.2 for a sample calculation as well).

As mentioned earlier, "weathered" crude and other petroleum liquids typically contain no CH_4 (or CO_2). For this reason, evaporative CH_4 (and CO_2) emissions do not occur. However, TOC evaporative emissions may be routed to a combustion control device, resulting in CO_2 emissions. Table B-11 provides simple emission factors for gasoline ballasting (EPA, AP-42 Table 5.2-6, 2008). Ballasting emissions factors are not available for petroleum products other than gasoline due to limited data.

Table B-11. Simplified TOC Emission Factors for Gasoline Ballasting Losses [a]

Operation	Units		Gasoline [b]
Tanker Ballasting	Original Units	lb TOC/10^3 gal ballast water	0.8
		mg/L ballast water	100
	Converted Units [c]	tonne TOC/ 106 gal water	0.379
		tonne TOC/ 103 m3 water	0.100

Footnotes and Sources:
[a] EPA, AP-42, Section 5, Table 5.2-6, 2008. The factors shown are for total organic compounds.
[b] The example gasoline has an RVP of 10 psia.
[c] 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/10^3 gallons.

B.4.3 Transit Loss Emissions

In addition to emissions resulting from petroleum loading operations and marine ballasting operations, TOC emissions also occur during petroleum transit. The mechanism resulting in transit losses is similar to breathing losses that occur for storage tanks.[3] For marine transit, the estimation methods are based on the availability of the fuel CH_4 (or CO_2, if present) content and other physical properties. For other transit modes, the choice of methods is based solely on the availability of the fuel CH_4 (or CO_2, if present) content.

For transit by marine vessel (i.e., ships and barges), Equation B-13 provides an emission estimate based on experimental tests on ships and barges (EPA, AP-42 Section 5.2, Equation 5, 2008).

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[3] Note that, as discussed in Section 6.3.9.3, CH_4 and CO_2 emissions from the working and breathing losses of storage tanks containing "live" crude are assumed to be negligible. In addition, it is assumed that there are no CH_4 or CO_2 emissions from the working and breathing losses of tanks containing weathered crude or other refined petroleum products.

$L_T = 0.1\ P\ W$ (Equation B-13)

where

L_T = ship and barge transit loss TOC emission factor, lb/week-10^3 gallon transported;
P = true vapor pressure of the liquid transported, psia; and
W = density of the condensed vapors, lb/gal.

The equation above provides a TOC emission factor, which is converted to CH_4 (or CO_2, if present) based on the concentration of CH_4 (or CO_2) in the fuel vapors. The vapor pressure (P) and vapor density (W) factors in Equation B-13 can be estimated from Table B-4 based on the average ambient temperature of the facility. If the CH_4 concentration for "live" crude is unknown, a typical value of 15 wt% can be assumed. As discussed earlier, for "weathered" crude and other petroleum products, there is no CH_4 (or CO_2). However, CO_2 emissions would result if the TOC evaporative emissions are routed to a combustion control device.

An exhibit calculation demonstrating the use of Equation B-13 in estimating transit loss emissions is shown in Exhibit B.10.

EXHIBIT B.10: Sample Calculation for Estimating Marine Transit Loss Emissions Associated with Crude Oil Transportation

INPUT DATA:
500,000 barrels of "weathered" crude oil (RVP 5) are transported via ships with an average trip duration of 10 days. The company transports crude 25 times during the given reporting year. The crude TOC vapors are 75% carbon by weight. Evaporative emissions are routed to a combustion control device. The average ambient temperature at the facility is 70°F (529.7°R) based on average annual meteorological data. Calculate the CO_2 emissions resulting from transit.

CALCULATION METHODOLOGY:
The vapor pressure and condensed vapor density of RVP 5 crude oil are taken from Table B-5. Using Equation B-13, the ship transit loss TOC emission factor is calculated as shown below:

$$L_T = (0.1)\times(3.4\text{ psi})\times(4.5\text{ lb/gal})$$

$$L_T = 1.53\text{ lb TOC/week-}10^3\text{ gal transported}$$

EXHIBIT B.10: Sample Calculation for Estimating Marine Transit Loss Emissions Associated with Crude Oil Transportation, continued

The transit loss emissions are obtained by multiplying the transit emission factor, L_T, by the duration of transport and the quantity of crude transported.

$$E_{TOC} = \frac{1.53 \text{ lb TOC}}{\text{week-}10^3\text{gal}} \times \frac{42 \text{ gal}}{\text{bbl}} \times 500{,}000 \text{ bbl} \times \frac{10 \text{ days}}{\text{trip}} \times \frac{25 \text{ trips}}{\text{year}} \times \frac{\text{week}}{7 \text{ days}} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$E_{TOC} = 520.5 \text{ tonnes TOC/yr}$$

The CO_2 emissions are then calculated by applying Equation B-11:

$$E_{CO_2} = \frac{520.5 \text{ tonnes TOC}}{\text{yr}} \times \frac{0.75 \text{ tonne C}}{\text{tonne TOC}} \times 0.99 \times \frac{44 \text{ lb } CO_2 \text{ / lbmole } CO_2}{12 \text{ lb C / lbmole C}}$$

$$\underline{E_{CO_2} = 1{,}417 \text{ tonnes } CO_2\text{/yr}}$$

Table 6-49 in Section 6.10.3 provides simple transit TOC emission factors for marine transit of crude oil (refer to Section 6.10.3 for a sample calculation as well). Gasoline transit TOC emission factors via rail or truck transit are provided in Table B-12 (EPA, AP-42 Section 5.2.2.1.3, 2008). Emission factors for marine transit of gasoline are provided in Table B-13 (EPA, AP-42 Section 5.2.2.1.3, 2008). Carbon dioxide emissions would result when the TOC evaporative emissions are routed to a combustion control device.

Table B–12. Simplified TOC Emission Factors for Rail/Truck Gasoline Transit Losses [a]

Transit Type	Units		Gasoline [b]
Loaded with Product			
Typical Operation	Original Units	lb TOC/10^3 gal transported	0 - 0.01
		mg TOC/L transported	0 - 1.0
	Converted Units [c]	tonne TOC/10^6 gal transported	0 - 0.0038
		tonne TOC/10^3 m^3 transported	0 - 0.0010
Extreme Operation	Original Units	lb TOC/10^3 gal transported	0 - 0.08
		mg TOC/L transported	0 - 9.0
	Converted Units [c]	tonne TOC/10^6 gal transported	0 - 0.034
		tonne TOC/10^3 m^3 transported	0 - 0.0090

Table B–12. Simplified TOC Emission Factors for Rail/Truck Gasoline Transit Losses [a], continued

Transit Type	Units		Gasoline [b]
Return with Vapor			
Typical Operation	Original Units	lb TOC/10^3 gal transported	0 - 0.11
		mg TOC/L transported	0 - 13.0
	Converted Units [c]	tonne TOC/10^6 gal transported	0 - 0.049
		tonne TOC/10^3 m^3 transported	0 - 0.0130
Extreme Operation	Original Units	lb TOC/10^3 gal transported	0 - 0.37
		mg TOC/L transported	0 - 44.0
	Converted Units [c]	tonne TOC/10^6 gal transported	0 - 0.167
		tonne TOC/10^3 m^3 transported	0 - 0.0440

Footnotes and Sources:

[a] EPA, AP-42, Section 5, Table 5.2-5, 2008. The emission factors for the other products listed above are for both TOC and VOC because AP-42 reports that the CH_4 and C_2H_6 content of the loading emissions is negligible for gasoline.

[b] The example gasoline has an RVP of 10 psia.

[c] 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/10^3 gallons.

Table B-13. Simplified TOC Emission Factors for Marine Transit Losses [a]

Operation	Units		Gasoline [b]
Marine Transit	Original Units	lb TOC/week-10^3 gal transported	2.7
		mg TOC/week-L transported	320
	Converted Units [c]	tonne TOC/week-10^6 gal transported	1.21
		tonne TOC/week-10^3 m^3 transported	0.320

Footnotes and Sources: .

[a] EPA, AP-42, Section 5, Table 5.2-6, 2008 The factors shown are for TOCs.

[b] The example gasoline has an RVP of 10 psia.

[c] 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/10^3 gallons.

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 PRV settings, the liquid vapor pressure, and the degree of vapor saturation in the vapor void space of the cargo tank. The rail and truck tanker emission factors are reported as a range for both “typical” and “extreme” conditions, where the “extreme” factors correspond to conditions that would result in maximum emissions. Note also that the rail and truck emission factors are reported in terms of mass of TOC per volume transported. Estimating emissions for these sources also requires the number of trips taken during the reporting year.

Exhibit B.11 illustrates the use of the simple gasoline transit emission factors.

EXHIBIT B.11: Sample Calculation for Estimating CH_4 Emissions Using Simplified Rail/Truck Transit Emission Factors

INPUT DATA:
8,000 gallons of gasoline (RVP 10) is transported via truck (8,000 gallons per trip). The company transports gasoline 100 times during the given reporting year. The gasoline vapors are 85 wt% carbon and are routed to a VCU with 99.5% combustion efficiency. Calculate the CO_2 emissions associated with the transit operations.

CALCULATION METHODOLOGY:
The transit loss emission factor given in Table B-12 for the truck when loaded with product for typical operation is 0-0.01 lb TOC/1000 gallons transported (0-0.0038 tonne TOC/10^6 gallon transported). For conservatism, the upper bound factor is used. Thus, the transit emissions when loaded with product are:

$$E_{TOC} = \frac{0.0038 \text{ tonne TOC}}{10^6 \text{ gal transported}} \times \frac{8000 \text{ gal}}{\text{trip}} \times \frac{100 \text{ trips}}{\text{yr}}$$

$$E_{TOC} = 0.00304 \text{ tonnes TOC/yr}$$

Similarly, the transit emissions of the truck when returning with vapor are estimated. The transit loss emission factor given in Table B-12 for the truck with vapor for typical operation is 0-0.11 lb TOC/1000 gallons transported (0-0.049 tonne TOC/10^6 gallon transported). For conservatism, the upper bound factor is used. Thus, the transit emissions when loaded with product are:

$$E_{TOC} = \frac{0.049 \text{ tonne TOC}}{10^6 \text{ gal transported}} \times \frac{8000 \text{ gal}}{\text{trip}} \times \frac{100 \text{ trips}}{\text{yr}}$$

$$E_{TOC} = 0.0392 \text{ tonnes TOC/yr}$$

The CO_2 emissions are then calculated by applying Equation B-11:

$$E_{CO_2} = \left(0.0392 + 0.00304\right) \frac{\text{tonnes TOC}}{\text{yr}} \times \frac{0.85 \text{ tonne C}}{\text{tonne TOC}} \times 0.995 \times \frac{44 \text{ lb } CO_2 / \text{lbmole } CO_2}{12 \text{ lb C} / \text{lbmole C}}$$

$$\underline{E_{CO_2} = 0.131 \text{ tonnes } CO_2/\text{yr}}$$

B.5 Production Sector High-/Low-Bleed Pneumatic Devices Emission Factor Development

Section 6.3.7 of the API *Compendium* presents simplified gas-driven pneumatic device emission factors by industry segment, including an emission factor for continuous bleed pneumatic devices in the production sector. This continuous bleed device emission factor was further split out according to whether the device is high-bleed or low-bleed. The EPA Gas STAR program defines a pneumatic device that bleeds more than 6 scfh as a “high-bleed” device, with “low-bleed” devices venting less than 6 scf/hr (EPA Gas STAR, Lessons Learned, July 2003). Therefore, the same data set that was used to develop the production sector continuous bleed device emission factor in Volume 12 of the 1996 GRI/EPA natural gas CH_4 emissions study (Shires and Harrison, 1996) was also used to develop the high- and low-bleed device emission factors by stratifying the data according to whether the leak rate is greater than or less than 6 scfh. The development of these emission factors is provided below in Table B-14.

Table B–14. Production Sector Pneumatic Device High/Low-Bleed Emission Factor Development [a]

			Stratification [b]	
Number	**Device Type**	**Bleed Rate (scf/day)**	**Low-Bleed, ≤ 6 scf/hr (scf/day)**	**High-Bleed, ≥ 6 scf/hr (scf/day)**
1	Norriseal 1001A	2334.1		2334.1
2	Fisher 2513	2170		2170
3	Fisher 4100	1065		1065
4	Norriseal 1001A	428		428
5	CE Invalco	1107		1107
6	Fisher 2500	596		596
7	Fisher 2502	962		962
8	Fisher 2900	954		954
9	Fisher 4150	634		634
10	Fisher 4160	560		560
11	Fisher 4160	380		380
12	Fisher 2900	1548		1548
13	CE Natco AE 155	1056		1056
14	Fisher 4160	609		609
15	Fisher 2900	508		508
16	Fisher 4150	145		145
17	Fisher 4160	108	108	
18	Fisher 4160	534		534
19	CPA Data	1.53	1.53	
20	CPA Data	59.92	59.92	
21	CPA Data	11.27	11.27	
22	CPA Data	34.50	34.50	
23	CPA Data	7.80	7.80	

Table B–14. Production Sector Pneumatic Device High/Low-Bleed Emission Factor Development [a], continued

Number	Device Type	Bleed Rate (scf/day)	Stratification [b] Low-Bleed, ≤ 6 scf/hr (scf/day)	High-Bleed, ≥ 6 scf/hr (scf/day)
24	CPA Data	529.04		529.04
25	CPA Data	10.68	10.68	
	Average (scf total gas/day): Uncertainty [c], ±:	654.1 40%	33.4 107%	895.5 33%
	Average (scf CH_4/day) [d]:	515.4	26.3	705.7
	Average (tonnes CH_4/device-yr) [e]:	3.609	0.184	4.941

Footnotes and Sources:

[a] Developed from data used for Volume 12 of the GRI/EPA natural gas industry CH_4 emissions study (Shires and Harrison, 1996).

[b] High-bleed devices refer to devices with leak rates greater than 6 scf/hr while low-bleed devices are 6 scf/hr or less based on definitions provided by EPA's Gas STAR program (EPA Gas STAR, Lessons Learned, July 2003).

[c] Uncertainty based on 95% confidence interval from the data used to develop the original emission factor.

[d] Converted from a total gas basis to a methane basis assuming 78.8 mole % CH_4 (Shires and Harrison, 1996).

[e] CH_4 emission factors converted from scf or m^3 are based on 60°F and 14.7 psia.

An example calculation illustrating the use of the high- and low-bleed classification for pneumatic device emissions follows.

EXHIBIT B.12: Sample Calculation for Gas-Driven Pneumatic Device Emissions

INPUT DATA:

A gas production site has 80 natural gas-driven pneumatic devices; 60 of the devices are low-bleed and the remaining 20 are high-bleed devices. The average CH_4 content of the gas is 70 mole %. There is also 9 mole % CO_2 in the gas. Calculate the CH_4 and CO_2 emissions.

CALCULATION METHODOLOGY:

The counts of high-bleed and low-bleed devices are multiplied by their respective emission factors from Table B-14.

$$E_{CH_4} = \left[(60 \text{ pneumatic devices}) \times \frac{0.184 \text{ tonne } CH_4}{\text{device - yr}} + (20 \text{ pneumatic devices}) \times \frac{4.941 \text{ tonne } CH_4}{\text{device - yr}} \right] \times \frac{70 \text{ mole \% } CH_4}{78.8 \text{ mole \% } CH_4}$$

$$\underline{E_{CH_4} = 97.59 \text{ tonnes } CH_4/\text{yr}}$$

EXHIBIT B.12: Sample Calculation for Gas-Driven Pneumatic Device Emissions, continued

$$E_{CO_2} = \left[(60 \text{ pneumatic devices}) \times \frac{0.184 \text{ tonne } CH_4}{\text{device - yr}} + (20 \text{ pneumatic devices}) \times \frac{4.941 \text{ tonne } CH_4}{\text{device - yr}} \right]$$

$$\times \left[\frac{70 \text{ mole \% } CH_4}{78.8 \text{ mole \% } CH_4} \times \frac{\text{tonne mole } CH_4}{16 \text{ tonne } CH_4} \times \frac{\text{tonne mole gas}}{0.70 \text{ tonne mole } CH_4} \times \frac{0.09 \text{ tonne mole } CO_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne } CO_2}{\text{tonne mole } CO_2} \right]$$

$$\underline{E_{CO_2} = 34.51 \text{ tonnes } CO_2/\text{yr}}$$

B.6 Additional Vented Volume Calculation Methodologies

This subsection presents additional calculation methodologies for estimating the volume of gas released in non-routine activities. After calculating the volume of gas released, CH_4 and CO_2 emissions from such releases would be calculated using an engineering approach, such as described in Table 6-1.

B.6.1 Calculating Pressure Vessel Volume

The volume of gas released from an equipment blowdown is typically based on equipment design specifications for the vessel/pipeline/equipment of interest. In the absence of design data, the CAPP document, *Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities*, provides guidance on estimating the volumes for several vessel types (CAPP, 2002, Section 3.2.4). These vessel types include horizontal and vertical cylinders, and hemispherical and ellipsoidal end caps.

The CAPP document also provides volumes per meter of pipeline length for several pipe sizes and schedules, which are presented in Table B-15.

Use of the gas law is most appropriate for situations where the entire volume of the vessel is blown down and the gas blowdown volume is finite. More rigorous engineering approaches are needed for a blowdown situation where only a portion of the vessel contents are released.

These approaches are based on modeling the releases as isentropic flow of an ideal gas through a nozzle. This approach requires release parameters such as the open cross-sectional area of the release, wellhead pressure, and the gas specific heat ratio (Cp/Cv). These approaches are most appropriate for releases that do not blow down the entire volume of interest. Refer to the CAPP document for more information on this approach, including an example calculation.

The CAPP document also provides a summary of cross-sectional areas for several pipe sizes and schedules (CAPP, 2002, Table 3-6). These areas are useful for applying the isentropic flow equation to estimate the blowdown rates.

Table B–15. Volume Per Meter of Pipeline Length

NPS Size	Volume Released (m^3/m) [a]							Volume Released (scf/ft) [a,b]						
	Sch 40	**Sch 60**	**Sch 80**	**Sch 100**	**Sch 120**	**Sch 140**	**Sch 160**	**Sch 40**	**Sch 60**	**Sch 80**	**Sch 100**	**Sch 120**	**Sch 140**	**Sch 160**
1	5.57E-04		4.64E-04				3.37E-04	6.00E-03		4.99E-03				3.62E-03
2	2.17E-03		1.91E-03				1.45E-03	2.33E-02		2.05E-02				1.56E-02
3	4.77E-03		4.26E-03				3.49E-03	5.13E-02		4.59E-02				3.76E-02
4	8.21E-03		7.42E-03		6.65E-03		5.99E-03	8.84E-02		7.99E-02		7.16E-02		6.44E-02
6	1.86E-02		1.68E-02		1.53E-02		1.37E-02	2.01E-01		1.81E-01		1.65E-01		1.47E-01
8	3.23E-02	3.09E-02	2.95E-02	2.80E-02	2.62E-02	2.48E-02	2.35E-02	3.47E-01	3.33E-01	3.17E-01	3.02E-01	2.82E-01	2.67E-01	2.53E-01
10	5.09E-02	4.82E-02	4.64E-02	4.40E-02	4.16E-02	3.88E-02	3.66E-02	5.48E-01	5.18E-01	4.99E-01	4.73E-01	4.48E-01	4.18E-01	3.94E-01
12	7.22E-02	6.85E-02	6.56E-02	6.20E-02	5.86E-02	5.59E-02	5.20E-02	7.77E-01	7.37E-01	7.06E-01	6.68E-01	6.30E-01	6.01E-01	5.59E-01
14	8.73E-02	8.32E-02	7.92E-02	7.45E-02	7.07E-02	6.70E-02	6.34E-02	9.39E-01	8.96E-01	8.52E-01	8.02E-01	7.61E-01	7.21E-01	6.83E-01
16	1.14E-01	1.09E-01	1.04E-01	9.84E-02	9.32E-02	8.73E-02	8.32E-02	1.23E+00	1.18E+00	1.12E+00	1.06E+00	1.00E+00	9.39E-01	8.96E-01
18	1.44E-01	1.38E-01	1.32E-01	1.25E-01	1.18E-01	1.12E-01	1.06E-01	1.55E+00	1.49E+00	1.42E+00	1.34E+00	1.27E+00	1.21E+00	1.14E+00
20	1.79E-01	1.71E-01	1.63E-01	1.54E-01	1.46E-01	1.38E-01	1.31E-01	1.93E+00	1.84E+00	1.75E+00	1.66E+00	1.58E+00	1.48E+00	1.41E+00

Footnotes and Sources:

[a] Canadian Association of Petroleum Producers (CAPP), Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities, Guide, Canadian Association of Petroleum Producers, Publication Number 2002-0009, May 2002, Table 3-8.

[b] Volumes were converted from m^3/m to scf/ft.

B.6.2 Calculating Well Unloading Emissions

CAPP (CAPP, 2002, Section 3.2.1) provides information on calculating the volume of gas released during well unloading. The total volume released is dependent on many properties, including the duration of the event, size of the vent line, quantity of water released, and properties of the gas. CAPP models the vent process as an isentropic flow of an ideal gas through a nozzle[4], as shown in Equation B-14.

$$\dot{m}_T = A^* \times \frac{P_0}{\sqrt{T_0}} \times \sqrt{\frac{k}{R}} \times \frac{1}{\left(\frac{k+1}{2}\right)^{(k+1) \div (2 \times k-2)}} \times 1000 \qquad \text{(Equation B-14)}$$

where

$\dot{m}_T$ = the total mass flow rate of gas and water vapor from the unloading (kg/s);
A^* = the cross sectional area of the unloading valve or vent pipe (m^2);
P_0 = wellhead pressure (kPa);
T_0 = wellhead temperature (K);
k = specific heat ratio, Cp/Cv (1.32 for natural gas); and
R = gas constant (kJ/kg K), (8314.5 / gas molecular weight).

The quantity of water produced during the unloading must be subtracted from the quantity of gas vented. Equation B-15 can be used to calculate the quantity of water vented:

$$\dot{m}_W = \frac{V \times \rho_w}{t} \qquad \text{(Equation B-15)}$$

where

$\dot{m}_W$ = mass flow rate of water produced by the unloading event (kg/s);
V = volume of liquid water produced by the unloading event (m^3);
ρ_w = density of liquid water (1000 kg/m^3); and
t = duration of the blow down event (s).

The mass flow rate of gas released is calculated using Equation B-16.

$$\dot{m}_V = \dot{m}_T - \dot{m}_W \qquad \text{(Equation B-16)}$$

where

$\dot{m}_v$ = mass flow rate of gas released.

The total volume of gas released is then calculated using Equation B-17.

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[4] CAPP notes that "modeling the system as an ideal gas yields good results up to wellhead pressures of about 50 atmospheres," but at higher pressures a more rigorous equation of state must be used (CAPP, 2002, Section 3.2.1).

$$V = \frac{\dot{m}_V \times t}{W_V} \times 23.6449 \qquad \text{(Equation B-17)}$$

where

V = volume of gas released (m^3);
W_V = molecular weight of the vapor released (kg/kmole); and
23.6449 = the volume (m3) occupied by one kmole of and ideal gas at 15ºC and 101.325 kPa.

B.6.3 Calculating Pressure Relief Valve Release Volumes

Emission factors for PRV releases are provided in Section 6.4.6.2. Alternatively, CAPP (CAPP, 2002, Section 3.2.3) provides information on calculating the volume of gas released during a PRV event. The total volume released is dependent on many properties, including the duration of the event, size of the relief valve, and properties of the gas. As for well unloading, CAPP models the vent process as an isentropic flow of an ideal gas through a nozzle,[5] as shown in Equation B-18.

$$\dot{m}_V = A^* \times \frac{P_0}{\sqrt{T_0}} \times \sqrt{\frac{k}{R}} \times \frac{1}{\left(\frac{k+1}{2}\right)^{(k+1) \div (2 \times k-2)}} \times 1000 \qquad \text{(Equation B-18)}$$

where

$\dot{m}_V$ = the total mass flow rate of gas through the PRV (kg/s);
A^* = the cross sectional area of the throat (or orifice) of the valve (m^2);
P_0 = PRV set point (kPa);
T_0 = vessel temperature (K);
k = specific heat ratio, Cp/Cv (1.32 for natural gas); and
R = gas constant (kJ/kg K), (8314.5 / gas molecular weight).

The total volume of gas released can then be calculated using Equation B-17.

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[5] CAPP notes that "modeling the system as an ideal gas yields good results up to wellhead pressures of about 50 atmospheres," but at higher pressures a more rigorous equation of state must be used (CAPP, 2002, Section 3.2.1).

B.7 Derivation of Vented Emission Factors

B.7.1 Derivation of Transmission Pipeline and Compressor Station Blowdown Emission Factor

The emission factors for pipeline and compressor station blowdowns are based on combined data from the GRI/EPA methane emissions study (Shires and Harrison, Volume 7, 1996) and the 1995 Canadian emissions study (Radian, 1997). Site data used in the development of these two studies were combined to establish the pipeline and compressor station blowdown emission factors.

Table B-16 presents the development of the transmission compressor station blowdown emission factor based on the combined U.S. and Canadian data.

Table B–16. Transmission Compressor Station Blowdown Emission Factor Development

Company Number	**Annual Station Blowdown Emissions (Mscf/yr)**	**Number of Stations**	**Annual Station Blowdown Emissions (MMscm CH_4/station)**	**Blowdown/Station [a] (Mscf CH_4/station-yr)**
U.S.Data [b]				
1	120,757	11		10,253.37
2	272,589	15		16,973.21
3	33,731	27		1,166.84
4	Not Available	19		-
5	325,418	47		6,466.82
6	Unknown	48		-
7	60,956	69		825.11
8	194,541	47		3,865.98
Canadian Data [c]				
1			0.00485	171.28
2			0.2995654	10,579.06
3			0.03056	1,079.22
4			No Data	-
5			0.248	8,758.05
6			0.0021015	74.21
7			0.096	3,390.21
Average Emission Factor, Mscf CH_4/station-yr [d]				**5,300.28±64.3%**

Footnotes and Sources:

[a] U.S. blowdown/station estimated by dividing the annual blowdown emissions by the number of stations and then multiplying by the default CH_4 content for the transmission sector, provided in Table D-4 (93.4 mole %).

[b] GRI/EPA methane emissions study (Shires and Harrison, 1996), Volume 7, page B-15.

[c] Company information developed as part of 1995 Canadian natural gas industry emissions study (Radian, 1997).

[d] Uncertainty based on 95% confidence interval.

Table B-17 presents the development of the transmission pipeline blowdown emission factor.

Table B–17. Transmission Pipeline Blowdown Vented Emission Factor Development

Company Number	Annual Pipeline Blowdown Emissions (Mscf/yr)	Pipeline Length (Miles)	Annual Pipeline Blowdown Emissions (MMscm CH_4/km)	Blowdown/ Mile [a] (Mscf CH_4/mile-yr)
U.S. Data [b]				
1	189,044	3,857		45.78
2	11,358	4,000		2.65
3	138,988	5,886		22.05
4	Not Available	5,450		-
5	Unknown	4,725		-
6	161,628	7,896		19.12
7	750,000	14,666		47.76
8	315,058	9,915		29.68
Canadian Data [c]				
1			0.001026	58.31
2			0.003199	181.83
3			0.000211	11.97
4			0.0000272	1.54
5			0.000355	20.15
6			0.00000828	0.47
7			0.001602	91.03
Average Emission Factor, Mscf CH_4/mile-yr [d]				**40.95 ± 73.3%**

Footnotes and Sources:

[a] U.S. blowdown/mile estimated by dividing the annual blowdown emissions by the number of miles and then multiplying by the default CH_4 content for the transmission sector, provided in Table D-4 (93.4 mole %).

[b] GRI/EPA methane emissions study (Shires and Harrison, 1996), Volume 7, page B-15.

[c] Company information developed as part of 1995 Canadian natural gas industry emissions study (Radian, 1997).

[d] Uncertainty based on 95% confidence interval.

B.7.2 Derivation of Pipeline Blowdowns Emission Factor

The emission factors for distribution pipeline blowdowns are based on combined data from the GRI/EPA (Shires and Harrison, 1996) and 1995 Canadian emissions studies (Radian, 1997; URS, 2001). Site data used in the development of these two studies were combined to establish the distribution pipeline vented blowdown emission factor as shown in Table B-18.

Table B–18. Distribution Pipeline Blowdown Vented Emission Factor Development

Company Number	Annual Pipeline Blowdown Emissions (Mscf/yr)	Pipeline Length (Miles)	Annual Pipeline Blowdown Emissions (MMscm CH_4/km)	Blowdown/Mile [a] (Mscf CH_4/mile-yr)
***U.S. Data* [b]**				
1	8,972	58,024		0.1546
2	5,688	82,337		0.0691
3	2,360	24,916		0.0947
4	1,695	18,713		0.0906
***Canadian Data* [c]**				
1			0.000136	7.73
2			0.00000271	0.15
3			0.0000907	5.15
4			0.00000130	0.07
5			0.000055	3.13
6			0.00000248	0.14
Average Emission Factor, Mscf CH_4/mile-yr [d]				**1.68 ± 117%**

Footnotes and Sources:

[a] U.S. blowdown/mile estimated by dividing the annual blowdown emissions by the number of miles, and then multiplying by the default CH_4 content for the distribution sector, provided in Table D-4 (93.4 mole %).

[b] GRI/EPA methane emissions study (Shires and Harrison, 1996), Volume 7, page B-20.

[c] Company information developed as part of 1995 Canadian natural gas industry emissions study (Radian, 1997).

[d] Uncertainty based on 95% confidence interval.

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Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Natural Gas and Oil Industry

Appendix C – Additional Fugitive Calculation Information

November 2021

Table of Contents

List of Tables

ADDITIONAL FUGITIVE CALCULATION INFORMATION

This section presents supplemental information for the fugitive emission calculation methodologies presented in Section 7.

C.1 Additional Equipment Leak Emission Calculation Data

C.1.1 Methane-Specific Data for Emission Rate Calculations

Most fugitive emission factors are for THC, TOC, or VOC. Methane emissions are included as part of the emissions from THC and TOC emission factors, but are excluded from VOC emission factors. It will be necessary to make some additional calculations to estimate CH_4 emissions from these types of emission factors. Calculating CH_4 fugitive emissions from THC or TOC emission factors is done using Equations 7-9 and C-1, and requires composition data. The best source of composition data is test data specific to the facility. If plant-specific test data are unavailable, Table C-1 provides "generic" speciation factors that can be applied to THC fugitive emissions to obtain compound specific emissions data. The table includes data on average CH_4 fractions of the THC fugitive emissions for various oil and gas industry operations. The composition data in Table C-1 are taken from API Publication 4615 (API, 1995).

Note that the CH_4 speciation factors in Table C-1 are not specified by the type of service (gas, light liquid or heavy liquid), but are instead provided as speciation factors (expressed as weight fractions) of the average CH_4 fraction that can be applied to the THC fugitive emissions from operations such as light crude production, heavy crude production, gas production, natural gas processing plants, and offshore oil and gas production. These fractions are not to be confused with actual weight fractions of the different species in the produced fluids. They are provided as a convenient average factor that can be used to speciate fugitive emissions when using the component specific emission factors provided in API 4615 given in Tables 7-4, 7-13, and 7-37.

Table C-1. "Generic" Speciation Factors for Component Specific THC Emissions Factors for Oil and Gas Operations

Best Applied To API 4615 Emission Factors

Compound	Onshore Operations				Offshore Oil and Gas
	Light Crude	Heavy Crude	Gas Production	Gas Plant	
Methane	0.613	0.942	0.920	0.564	0.791
NMHC [a]	0.387	0.058	0.080	0.436	0.210
VOC [b]	0.292	0.030	0.035	0.253	0.110
C6+	0.02430	0.00752	0.00338	0.00923	0.00673
Benzene	0.00027	0.00935	0.00023	0.00123	0.00133
Toluene	0.00075	0.00344	0.00039	0.00032	0.00089
Ethylbenzene	0.00017	0.00051	0.00002	0.00001	0.00016
Xylenes	0.00036	0.00372	0.00010	0.00004	0.00027

Footnotes and Sources:
American Petroleum Institute (API). *Emission Factors for Oil and Gas Production Operations,* API Publication No. 4615, Health and Environmental Sciences Department, January 1995, Table ES-4.
[a] NMHC = Non-methane hydrocarbon.
[b] VOC = Propane and heavier hydrocarbon.

Additionally, Table C-2 provides generic fugitive stream composition data based on a Canadian study of upstream oil and gas operations in Alberta (Picard, Vol. II, 1992). Unlike the data in Table C-6, the composition data in Table C-2 are specified by gas or liquid service. As noted in the table title, these compositions are best applied to service specific emission factors, such as from EPA Protocol factors shown in Table 7-14. Note that EMEP/CORINAIR guidance (Group 5, Tables 8.31 and 8.32) recommends using the Canadian composition data (EEA, 2001).

The usage of the compositions provided in Table C-2 are described below.

- Dry gas profile is applied to low-pressure gas gathering systems and to gas batteries;
- Sweet gas profiles are used for dehydrated gas gathering systems and sweet gas processing plants;
- Sour gas profiles are dedicated to heated gas gathering systems and to sour gas processing plants; however, all fuel gas is assumed to be sweet;
- The natural gas profile is used for natural gas transmission systems; and
- Conventional oil, heavy oil, and crude bitumen profiles are applied to corresponding production and battery facilities. Heavy liquid service composition data also applies to vapors from storage tanks.

Table C-2. "Generic" Production (Canadian) Composition by Service [a]

Best Applied To Service-Specific Emission Factors

	Dry Gas - Gas Service		Sweet Gas - Gas Service		Sweet Gas – Light Liquid Service		Sour Gas - Gas Service		Sour Gas – Light Liquid Service		Natural Gas	
Compound	**Mole %[b]**	**Weight %[c]**	**Mole %[b]**	**Weight %[c]**	**Mole %[b]**	**Weight %[c]**	**Mole %[b]**	**Weight %[c]**	**Mole %[b]**	**Weight %[c]**	**Mole %[b]**	**Weight %[c]**
N_2	1.0914	1.8618	0.6793	1.0866	0.0000	0.0000	0.6552	1.0140	0.0000	0.0000	0.6793	1.0866
CO_2	0.2674	0.7167	0.5814	1.4612	0.0000	0.0000	0.5608	1.3637	0.0000	0.0000	0.5814	1.4612
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	3.5460	6.6772	0.0000	0.0000	0.0000	0.0000
C1	97.4524	95.1997	91.8796	84.1609	0.0000	0.0000	88.6210	78.5410	0.0000	0.0000	91.8796	84.1609
C2	1.1439	2.0949	5.4263	9.3180	6.2600	3.8133	5.2339	8.6959	6.2600	3.8133	5.4263	9.3180
C3	0.0389	0.1045	1.0490	2.6418	60.4300	53.9867	1.0118	2.4654	60.4300	53.9867	1.0490	2.6418
i-C4	0.0018	0.0064	0.1291	0.4285	10.9300	12.8689	0.1245	0.3998	10.9300	12.8689	0.1291	0.4285
n-C4	0.0034	0.0120	0.1949	0.6469	16.4000	19.3092	0.1880	0.6037	16.4000	19.3092	0.1949	0.6469
i-C5	0.0004	0.0018	0.0254	0.1047	1.6600	2.4263	0.0245	0.0977	1.6600	2.4263	0.0254	0.1047
n-C5	0.0005	0.0022	0.0296	0.1220	1.4300	2.0901	0.0286	0.1140	1.4300	2.0901	0.0296	0.1220
C6	0.0000	0.0000	0.0060	0.0295	1.2000	2.0950	0.0058	0.0276	1.2000	2.0950	0.0060	0.0295
C7+	0.0000	0.0000	0.0000	0.0000	1.6800	3.4105	0.0000	0.0000	1.6800	3.4105	0.0000	0.0000
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table C–2. "Generic" Production (Canadian) Composition by Service [a], continued

Best Applied To Service-Specific Emission Factors

Compound	Conventional Oil - Gas Service		Conventional Oil - Light Liquid Service		Heavy Oil (Primary) - Gas Service		Heavy Oil (Primary) – Vapor/Heavy Liquid Service		Heavy Oil (Thermal) - Gas Service		Heavy Oil (Thermal) – Vapor/Heavy Liquid Service		Crude Bitumen - Gas/Vapor/Heavy Liquid Service	
	Mole % [b]	Weight % [c]	Mole % [b]	Weight % [c]	Mole % [b]	Weight % [c]	Mole % [b]	Weight % [c]	Mole % [b]	Weight % [c]	Mole % [b]	Weight % [c]	Mole % [b]	Weight % [c]
N_2	0.6190	0.7723	13.9989	8.8634	0.1817	0.3030	6.3477	8.9367	0.1932	0.1767	3.3516	3.0550	0.0000	0.0000
CO_2	5.2430	10.2775	0.3303	0.3286	0.0859	0.2251	0.6892	1.5246	2.6094	3.7488	16.1140	23.0785	22.0000	41.5263
H_2S	0.0000	0.0000	0.0000	0.0000	0.0001	0.0002	0.0000	0.0000	0.0150	0.0167	0.1439	0.1596	0.0000	0.0000
C1	73.2524	52.3339	10.0100	3.6294	98.0137	93.6014	87.2337	70.3291	72.9361	38.1894	66.6600	34.7954	70.0000	48.1562
C2	11.9708	16.0329	15.7274	10.6902	0.9062	1.6224	2.2616	3.4182	1.9370	1.9013	0.9490	0.9286	8.0000	10.3175
C3	5.3198	10.4494	24.1601	24.0842	0.0408	0.1071	0.1905	0.4223	3.0956	4.4564	0.5394	0.7741	0.0000	0.0000
i-C4	0.8778	2.2724	6.6404	8.7240	0.0564	0.1952	0.1324	0.3868	1.0807	2.0503	0.1922	0.3635	0.0000	0.0000
n-C4	1.7027	4.4078	16.6022	21.8115	0.0351	0.1215	0.1137	0.3321	2.3889	4.5323	0.3678	0.6956	0.0000	0.0000
i-C5	0.3570	1.1473	4.2113	6.8683	0.0501	0.2152	0.1400	0.5077	1.9994	4.7090	0.4541	1.0662	0.0000	0.0000
n-C5	0.3802	1.2218	4.5447	7.4120	0.0433	0.1860	0.1230	0.4461	2.2733	5.3541	0.5829	1.3686	0.0000	0.0000
C6	0.2446	0.9389	2.9655	5.7770	0.0927	0.4756	0.3494	1.5135	5.8086	16.3408	2.1914	6.1458	0.0000	0.0000
C7+	0.0327	0.1460	0.7997	1.8115	0.4940	2.9473	2.4188	12.1831	5.6628	18.5242	8.4539	27.5689	0.0000	0.0000
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Footnotes and Sources:

[a] Picard, D. J., B. D. Ross, and D. W. H. Koon. *A Detailed Inventory of CH_4 and VOC Emissions from Upstream Oil and Gas Operations in Alberta*, Volume II Development of the Inventory, Canadian Petroleum Association, March 1992, Tables 12 through 15.

[b] Original composition provided in mole percent on a moisture-free (dry) basis.

[c] Compositions were converted from mole percents to weight percents using the approach described in Section 3.6.4 of this API *Compendium*.

C.1.2 Generic Component Counts

When using the component-level average emission factors, site-specific data should be used for the component counts. If site-specific counts are not available, then component counts may be estimated based on counts for similar facilities within the organization. In the absence of component counts from other similar facilities within the organization, Table C-3 provides generic component counts for U.S. onshore natural gas production and gathering and boosting facilities, and Table C-4 provides generic counts for U.S. onshore crude oil production for the Eastern and Western U.S. (EPA, 2019). These generic counts provide the number of components per piece of process equipment or process type. The counts are not split according to liquid or vapor service, so equipment with components in both liquid and vapor service (e.g. separators, dehydrator) could be assumed to have components that are 50% in liquid service and 50% in vapor service.

Table C-3. "Generic" Fugitive Component Counts for Major U.S. Onshore Natural Gas Production Equipment and Onshore Petroleum and Natural Gas Gathering and Boosting Equipment [a]

Major equipment	Valves	Connectors	Open-ended lines	Pressure relief valves
Eastern U.S.				
Wellheads	8	38	0.5	0
Separators	1	6	0	0
Meters/piping	12	45	0	0
Compressors	12	57	0	0
In-line heaters	14	65	2	1
Dehydrators	24	90	2	2
Western U.S.				
Wellheads	11	36	1	0
Separators	34	106	6	2
Meters/piping	14	51	1	1
Compressors	73	179	3	4
In-line heaters	14	65	2	1
Dehydrators	24	90	2	2

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (EPA). U.S. Environmental Protection Agency (EPA). Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Data reported as of August 2, 2019. https://ecfr.io/Title-40/sp40.23.98.w. Table W-1B to Subpart W of Part 98 GHGRP.

Table C-4. "Generic" Fugitive Component Counts for Major U.S. Onshore Crude Oil Production Equipment[a]

Major equipment	Valves	Flanges	Connectors	Open-ended lines	Other Components
Eastern U.S.					
Wellhead	5	10	4	0	1
Separator	6	12	10	0	0
Heater-treater	8	12	20	0	0
Header	5	10	4	0	0
Western U.S.					
Wellhead	5	10	4	0	1
Separator	6	12	10	0	0
Heater-treater	8	12	20	0	0
Header	5	10	4	0	0

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (EPA). U.S. Environmental Protection Agency (EPA). Greenhouse Gas Reporting Program – Subpart W – Petroleum and Natural Gas Systems. Data reported as of August 2, 2019. https://ecfr.io/Title-40/sp40.23.98.w. Table W-1C to Subpart W of Part 98 GHGRP.

Table C-5 provides alternate generic component counts for onshore oil production facilities. Table C-6 provides alternate generic component counts for onshore production, onshore gas processing, and offshore oil and gas production platform facilities. These alternate generic fugitive component counts are taken from a CAPP report (CAPP, 2003), which is based on API Publication 4589 (API, 1993). The generic counts were based on a study of 20 different sites. CAPP also provides more detailed component counts by equipment type for the upstream oil and gas industry (CAPP, 2004).

Note that the UKOOA provides adjustment factors that can be applied to the fugitive component emission calculation based on the age of the facility. These factors are 1.0 if built after 1988, 1.3 if built between 1980 and 1988, and 1.5 if built before 1980 (UKOOA, 2002). Thus, these factors would be applied to the component count times the component emission factor to adjust the emission estimate [i.e. $E_{CH4} = FA \times WF_{CH4} \times N \times$ (age correction)]. However, using these adjustment factors is optional, and the facility should evaluate whether they are representative for their operations. These factors should only be used for onshore exploration and production facilities where an LDAR program is not used. Thus, downstream facilities such as a refinery should not use these factors.

A summary of the number of vessels, compressors, and pumps associated with various natural gas processes is presented in Table C-7.

Table C-5. Alternate "Generic" Fugitive Counts for Onshore Oil Production Facilities (per Equipment/Process Type)

Equipment/ Process	Light Onshore Oil Production [a,b,c]					Heavy Onshore Oil Production [a,b,c]				
	Connectors	Valves	Open-Ended Lines	Compressor Seals	PRVs	Connectors	Valves	Open-Ended Lines	Compressor Seals	PRVs
Well	53	13	2		1	44	8	3		
Header	389	109	4			108	17	4		3
Heater	146	28	3							
Separator	111	24	3		1	41	10	2		
Chiller	94	25	1							
Meter	91	21	4							
Dehydrator	119	26								
Sulfur	109	34	7							
Compressor	163	34	2	1						
Scrubber	105	22	3							
Flare	114	35	5							

Footnotes and Sources:

[a] Canadian Association of Petroleum Producers (CAPP). *Calculating Greenhouse Gas Emissions*, Guide, Canadian Association of Petroleum Producers, Publication Number 2003-0003, April 2003, Tables 1-15 through 1-19.

[b] American Petroleum Institute (API). *Fugitive Hydrocarbon Emissions from Oil and Gas Production Operations*, API Publication No. 4589, Health and Environmental Sciences Department, December 1993.

[c] Light oil refers to crude with an API gravity of 20° or more, while heavy oil refers to crude with an API gravity less than 20°.

Table C-6. Alternate "Generic" Fugitive Counts for Gas Production, Gas Processing, and Offshore Facilities

(per Equipment/Process Type)

Equipment/ Process	Gas Production [a,b]					Gas Processing Plants [a,b]					Offshore Oil and Gas Production Platforms [a,b]				
	Connectors	**Valves**	**Open-Ended Lines**	**Compressor Seals**	**PRVs**	**Connectors**	**Valves**	**Open-Ended Lines**	**Compressor Seals**	**PRVs**	**Connectors**	**Valves**	**Open-Ended Lines**	**Compressor Seals**	**PRVs**
Well	60	16	3								195	61	20		
Header	105	26	4			145	38	4			310	82	14		2
Heater	147	22	4		2						197	45	4		2
Separator	160	30	5		3	48	17	3			299	81	11		1
Filter	122	19	3								269	42	8		2
Meter	55	13	2		2	160	41	13		2	383	84	10		4
Dehydrator	155	31	5			105	25	3		2	210	46	5		1
Fractionation						81	23	2		1					
Sulfur						144	42	3							
Compressor	195	31	5	2	3	129	26	2	3	4	417	88	12	2	3
Vapor Recovery	78	10	3								162	41	8		1
Scrubber	120	24	2		2	81	23	2			177	39	5		1
Flare						221	71	1			376	74	11		1

Footnotes and Sources:

[a] Canadian Association of Petroleum Producers (CAPP). *Calculating Greenhouse Gas Emissions*, Guide, Canadian Association of Petroleum Producers, Publication Number 2003-0003, April 2003, Tables 1-15 through 1-19, which are based on:

[b] American Petroleum Institute (API). *Fugitive Hydrocarbon Emissions from Oil and Gas Production Operations*, API Publication No. 4589, Health and Environmental Sciences Department, December 1993.

Table C-7. Summary of the Number of Vessels, Compressors, and Pumps Associated with Various Natural Gas Processes

Process	Vessels	Compressors	Pumps
Absorption	13	0	1
Adsorption	5	1	0
Chemsweet	5	1	0
Cold Bed Absorption	6	0	0
Compression	4	1	0
Cycling	12	1	2
DEA-Diethanolamine	13	0	1
DGA-Diglycolamine	13	0	1
Deepcut	14	1	2
Deethanizing	10	1	2
Dehydration	5	1	0
Demethanizing	10	1	2
Desiccant	5	1	0
Dewpoint	6	2	2
Fractionation	12	1	2
Iron Sponge	6	0	0
LoCat	5	1	0
MCRC - Sub-dewpoint sulphur recovery	6	0	0
MDEA - Monodiethanolamine	13	0	1
MEA - Monoethanolamine	13	0	1
Molecular Sieve	5	1	0
NGL - Natural gas liquid	14	1	2
Physical Solvent	12	1	1
Proprietary Sweetening	13	0	1
Refrigeration	6	2	2
Selexol	12	1	1
Separation	3	0	1
Sluri-sweet	13	0	1
Stabilization	8	0	1
Sulfacheck	12	1	1
Sulfinol	12	1	1
Sulfreen	6	0	0
Sweetening	13	0	1
Turbo Expander	1	1	0

Sources:
Clearstone Engineering Ltd. A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H_2S) Emissions by the Upstream Oil and Gas Industry, Volume 5, September 2004.

C.2 Refinery Fugitive Emissions

As noted in Section 6 and Appendix F, refinery fugitive emissions will generally have an insignificant contribution to the total GHG inventory because most refinery streams do not contain CH_4 (as demonstrated in Appendix E). Note that leaks from equipment used in association with "weathered" crude or other refined petroleum products will not emit CH_4 or CO_2, as "weathered" crude and refined petroleum products do not contain CH_4 or CO_2.[1]

The estimation method for refinery fugitive emissions provided in Section 6 is consistent with the materiality of fugitive emissions relative to total GHG emissions from refinery operations. Alternatively, this subsection presents more detailed emission estimation methodologies for refineries.

Refinery component-level average emission factors are presented in Table C-8. The component-level average factors should be used in accordance with the methodology discussed in Section 7.4.1. The refinery component-level average emission factors are expressed as VOC, where VOC = TOC – CH_4. To correct these factors to a CH_4 basis, the emission factor, F_A, must be adjusted to account for all organic compounds in the stream because the refinery factors are expressed in non-CH_4 (VOC) organic compounds. The equation below illustrates the emission factor adjustment that corrects the VOC emission factor to a CH_4 basis:

$$E_{CH_4} = F_{A\ VOC} \times \frac{WF_{CH_4}}{WF_{TOC} - WF_{CH_4}} \times N \qquad \text{(Equation C-1)}$$

where

E_{CH_4} = emission rate of CH_4 from all components of a given type in the stream;

$F_{A\ VOC}$ = average emission factor (as VOC);

WF_{TOC} = average weight fraction TOC in the stream;

WF_{CH_4} = weight fraction of CH_4 in the TOC; and

N = number of components of the given type in the stream.

When applied to refineries, the correction should only be applied to components containing a mixture of CH_4 and organic compounds. The maximum CH_4 concentration correction should not

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[1] For more information, see Appendix E.

exceed 10 weight percent, even if a stream contains more than 10 weight percent CH_4. This limitation generally is not an issue for refinery streams because they contain very little CH_4. The exceptions are for the refinery natural gas system and potentially the fuel gas system, in which case the gas service emission factors from Table 7-46 may be more representative and applicable to the higher CH_4 concentrations.

EPA average emission factors for refineries are provided in Table C-8 (EPA, 1995). As noted in Section 7, although these emission factors are reported in terms of individual components, the average emission factor approach is intended for application to a population of components. Note also that the emission factors in Table C-8 are service specific.

Table C-8. EPA Average Refinery Emission Factors [a]

	Emission Factor	
Component – Service [b]	**kg VOC/hr/comp.**	**tonne VOC/hr/comp.**
Valves – Gas	2.68E-02	2.68E-05
Valves – Light Liquid	1.09E-02	1.09E-05
Valves – Heavy Liquid	2.3E-04	2.3E-07
Pump Seals – Light Liquid	1.14E-01	1.14E-04
Pump Seals – Heavy Liquid	2.1E-02	2.1E-05
Compressor Seals – Gas	6.36E-01	6.36E-04
Pressure Relief Valves – Gas	1.6E-01	1.6E-04
Connectors – All	2.5E-04	2.5E-07
Open-ended Lines – All	2.3E-03	2.3E-06
Sampling Connections – All	1.50E-02	1.50E-05

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (EPA). *Protocol for Equipment Leak Emission Estimates*, EPA-453/R-95-017, EPA Office of Air Quality Planning and Standards, November 1995, Table 2-2. These emission factors were developed from testing performed in the 1970s and represent average emissions from uncontrolled components (i.e., components that are not subject to leak detection and repair programs). These emission factors can be converted to a CH_4 basis using Equation 6-8.

[b] EPA defines light liquids as liquids for which the sum of the concentration of individual constituents with a vapor pressure over 0.3 kPa at 20 °C is greather than or equal to 20 weight percent. EPA defines heavy liquids as liquids not in gas/vapor or light liquid service.

Screening range factors for refineries are presented in Table C-9. These emission factors should be used in accordance with the methodology described in Section 7.2.1.5. The refinery screening range factors are given in VOC rather than TOC. Equation C-1 presents the correction for refinery emission factors from a VOC to a CH_4 basis.

Table C-9. Refinery Screening Factors

	Emission Factor [a] (kg VOC/hr/comp.)		Emission Factor (tonne VOC/hr/comp.)	
Component – Service [b]	**<10,000 ppmv**	**≥10,000 ppmv**	**<10,000 ppmv**	**≥10,000 ppmv**
Valves – Gas	6.00E-04	2.63E-01	6.00E-07	2.63E-04
Valves – Light Liquid	1.70E-03	8.52E-02	1.70E-06	8.52E-05
Valves – Heavy Liquid	2.30E-04	2.30E-04	2.30E-07	2.30E-07
Pump Seals – Light Liquid	1.20E-02	4.37E-01	1.20E-05	4.37E-04
Pump Seals – Heavy Liquid	1.35E-02	3.89E-01	1.35E-05	3.89E-04
Compressor Seals – Gas	8.94E-02	1.61E+00	8.94E-05	1.61E-03
Pressure Relief Valve – Gas	4.47E-02	1.69E+00	4.47E-05	1.69E-03
Connectors – All	6.00E-05	3.75E-02	6.00E-08	3.75E-05
Open-Ended Lines – All	1.50E-03	1.20E-02	1.50E-06	1.20E-05

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (EPA). *Protocol for Equipment Leak Emission Estimates*, EPA-453/R-95-017, EPA Office of Air Quality Planning and Standards, November 1995, Table 2-6.

[b] EPA defines light liquids as liquids for which the sum of the concentration of individual constituents with a vapor pressure over 0.3 kPa at 20 °C is greather than or equal to 20 weight percent. EPA defines heavy liquids as liquids not in gas/vapor or light liquid service.

Note: These emission factors do not apply to streams containing >10% CH_4.

If a specific downstream operation has potentially significant CH_4 fugitive emissions, then the CH_4 weight fraction should be characterized using plant-specific data. In the absence of plant-specific composition data, Table D-3 provides "generic" vapor phase speciation data for "weathered" crude oil and refined petroleum products based on data taken from the EPA's SPECIATE computer database program, Version 4.0 (EPA, 2006). Although the EPA compositions are not specific to the type of service, these compositions can be applied to the refinery emission factors provided in Table C-9.

C.3 Derivation of Fugitive Emission Factors

This section provides the derivation of fugitive emission factors provided in Section 6. Factor derivations are presented in this section by industry segment.

C.3.1 Onshore Oil Production Fugitive Emission Factor

The onshore oil production fugitive emission factor presented in Table 7-8 was developed using data presented in the EPA petroleum industry CH_4 emissions study (Harrison, et al., 1998). All identified onshore fugitive emission sources are combined into this single emission factor. The precision data was calculated using data presented in Volume 8 of the GRI/EPA study (Hummel, et al., 1996). Emissions were calculated by dividing the total CH_4 emissions for onshore oil production by the total volume of oil produced (DOE, 1993). The factor derivation is presented in Table C-10.

Table C-10. Derivation of Facility-Level Average Fugitive Emission Factor for Onshore Oil Production

Source	U.S. Methane Emissions [a,b], Bscf CH_4/yr	Uncertainty [c], (± %)
Oil Wellheads (heavy crude)	0.012	128
Oil Wellheads (light crude)	3.879	128
Separators (heavy crude)	0.003	110
Separators (light crude)	2.118	102
Heater/Treaters (light crude)	1.687	166
Headers (heavy crude)	0.003	139
Headers (light crude)	3.500	141
Tanks (light crude)	0.681	141
Small Compressor (light crude)	0.011	192
Large Compressor (light crude)	11.585	192
Sales Areas	0.066	66.4
Pipelines [d]	1.441	154
Total Emissions	24.986	95.0
Activity Data		
National Onshore Crude Oil Production [e]	2,042,625,000 bbl/yr	10
CH_4 Emission Factor		
Emission Factor Development	EF = (24.986 x 10^9 scf CH_4/yr) ÷ (2,042,625,000 bbl oil/yr) =12.232 scf CH_4/bbl	**95.5**
Onshore Oil Production Fugitive Emission Factor, Converted to lb CH_4/bbl oil	**0.5173 lb CH_4/bbl oil**	

Footnotes and Sources:

[a] Harrison, M.R., T.M. Shires, R.A. Baker, and C.J. Loughran. *Methane Emissions from the U.S. Petroleum Industry, Final Report*, EPA-600/R-99-010. U.S. Environmental Protection Agency, February 1999.

[b] Hummel, K.E., L.M. Campbell, and M.R. Harrison. *Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Final Report*, GRI-94/0257.25 and EPA-600/R-96-080h. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[c] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[d] Because the data used to calculate the reference emission factor were unavailable, the precision at a 95% confidence interval was calculated based on the precision at a 90% confidence interval presented in the source assuming a data set size of ten.

[e] DOE, Petroleum Supply Annual, 1993. An uncertainty factor of 10% was assigned based on engineering judgment.

C.3.2 Onshore Gas Production Fugitive Emission Factors

The onshore gas production facility-level average fugitive emission factor presented in Table 7-8 was developed using data presented in Appendix A of Volume 2 of the GRI/EPA study (Harrison, et al., 1996). All identified onshore fugitive emission sources are combined into this single emission factor. The precision data were calculated using data presented in Volume 8 of the GRI/EPA study (Hummel, et al., 1996). Emissions were calculated by dividing the total CH_4 emissions for onshore gas production by the total volume of gas produced (DOE, 1993). The factor derivation is presented in Table C-11.

Table C-11. Derivation of Facility-Level Average Fugitive Emission Factor for Onshore Gas Production

Source	U.S. Methane Emissions [a,b], Bscf CH_4/yr	Uncertainty [c], (± %)
Gas Wells (Eastern onshore)	0.3352	32.8
Gas Wells (Rest of U.S. onshore)	1.8991	29.3
Heaters (Eastern onshore)	0.0013	260
Heaters (Rest of U.S. onshore)	1.0689	131
Separators (Eastern onshore)	0.0301	43.0
Separators (Rest of U.S. onshore)	3.3257	81.8
Small Reciprocating Compressors (Eastern onshore)	0.0006	87.7
Small Reciprocating Compressors (Rest of U.S. onshore)	1.6531	111
Large Reciprocating Compressors	0.5328	162
Large Reciprocating Compressor Stations	0.0361	210
Meters/Piping (Eastern onshore)	0.2508	130
Meters/Piping (Rest of U.S. onshore)	5.8158	130
Dehydrators (Eastern onshore)	0.0083	49.0
Dehydrators (Rest of U.S. onshore)	1.2233	38.8
Pipeline Leaks	6.6060	129
Total Emissions	22.7871	52.7
Activity Data		
Gross Onshore National Gas Production [d]	16,808 Bscf/yr	5
CH_4 Emission Factor		
Emission Factor Development	EF = (22.7871 × 10^9 scf CH_4/yr) ÷ (16,808 × 10^9 scf gas/yr) × (10^6/MM) = 1,356 scf CH_4/MMscf	**52.9%**
Onshore Gas Production Fugitive Emission Factor, Converted to lb CH_4/MMscf gas	**57.33 lb CH_4/MMscf**	

Footnotes and Sources:

[a] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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.

[b] Hummel, K.E., L.M. Campbell, and M.R. Harrison. *Methane Emissions from the Natural Gas Industry*, *Volume 8: Equipment Leaks*, *Final Report*, GRI-94/0257.25 and EPA-600/R-96-080h. Gas Research Institute and U.S. Environmental Protection Agency, June 1996. Component emission factors for onshore production in the Eastern U.S. were based on a measurement program of 192 well sites at 12 eastern gas production facilities. Site visits and phone surveys of 7 additional sites provided data used for determining the number of heaters and dehydrators. Component emissions factors for onshore production in the Western U.S. were based on a comprehensive fugitive emissions measurement program at 12 sites. An additional 13 sites were visited as part of the GRI/EPA study to develop average component counts for each piece of major process equipment

[c] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[d] DOE, *Natural Gas Annual*, 1993. An uncertainty factor of 5% was assigned based on engineering judgment.

The onshore gas production equipment level CH_4 fugitive emission factors presented in Table 7-10 were developed using emissions data presented in Appendix A of Volume 2 of the GRI/EPA study

(Harrison, et al., 1996). All identified onshore fugitive emissions are combined into this single emission factor except pipeline related fugitives. The precision data were calculated using data presented in Volume 9 of the GRI/EPA study (Campbell, et al., 1996). Source type emissions were calculated by dividing the sum of the CH_4 emissions for "Eastern Onshore" and "Rest of U.S." by the total national equipment counts.

Component emission factors for onshore production in the "Eastern U.S." were based on a measurement program of 192 well sites at 12 eastern gas production facilities. Site visits and phone surveys of 7 additional sites provided data used for determining the number of heaters and dehydrators. Component emission factors for onshore production in the "Rest of U.S." were based on a comprehensive fugitive emissions measurement program at 12 sites. An additional 13 sites were visited as part of the GRI/EPA study to develop average component counts for each piece of major process equipment (Campbell, et al., 1996). Table C-12 presents the factor derivations by equipment type.

Table C-12. Derivation of Equipment-Level Fugitive Emission Factors for Gas Production [a]

	Emissions [b,c], Bscf CH_4/yr			**National Equipment Counts [b,c]**			**Emission Factor, scf CH_4/ equip.**
Source	**Eastern Onshore [d]**	**Rest of U.S. [e]**	**Total**	**Eastern Onshore**	**Rest of U.S.**	**Total**	
Gas Wellheads	0.3352 ±32.8%	1.8991 ± 29.3%	2.2343 ± 25.4%	129,157 ± 5.97%	142,771 ± 5.97%	271,928± 4.22%	8,217 ± 25.7%
Gas Separators	0.0301 ± 43.0%	3.3257 ± 81.8%	3.3557 ± 81.0%	91,670 ± 27.5%	74,674 ± 68.0%	166,344 ± 34.1%	20,174 ± 87.9%
Gas Heaters	0.0013 ± 260%	1.0689 ±131%	1.0702 ±131%	260 ± 234%	50,740 ± 114%	51,000 ± 113%	20,985 ± 173%
Gas Small Gathering Compressor	0.0006 ± 87.7%	1.6531 ± 111%	1.6537 ± 111%	129 ± 66.4%	16,915 ± 62.3%	17,044 ± 61.8%	97,023 ± 127%
Gas Large Gathering Compressor	0	0.5328 ± 162%	0.5328 ± 162%	0	96.0 ± 120%	96.0 ± 120%	5,550,000 ± 202%
Gas Meters/Piping	0.2508 ± 130%	5.8158 ± 130%	6.0666 ± 125%	76,262 ± 120%	301,180 ± 120%	377,442 ± 98.5%	16,073 ± 159%
Gas Dehydrators	0.0083 ± 49.0%	1.2233 ± 38.8%	1.2316 ± 38.6%	1,047 ± 24.0%	36,777 ± 24.0%	37,824 ± 23.3%	32,561 ± 45.1%

Footnotes and Sources:

[a] Uncertainty values are based on 95% confidence intervals, converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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.

[c] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, *Final Report*, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[d] Component emission factors for onshore production in the Eastern U.S. were based on a measurement program of 192 well sites at 12 eastern gas production facilities. Site visits and phone surveys of 7 additional sites provided data used for determining the number of heaters and dehydrators (Campbell, et al., 1996).

[e] Component emissions factors for onshore production in the Western U.S. were based on a comprehensive fugitive emissions measurement program at 12 sites. An additional 13 sites were visited as part of the GRI/EPA study to develop average component counts for each piece of major process equipment (Campbell, et al., 1996).

The gathering pipeline fugitive emission factors presented in Table 7-10 were developed using emissions data presented in Volume 9 of the GRI/EPA study (Campbell, et al., 1996). The original emissions data in the GRI/EPA report were given in terms of CH_4 emissions on an equivalent leak basis; the emission factors were converted to a pipeline mile basis using pipeline miles presented in Volume 9 of the GRI/EPA study (Campbell, et al., 1996).

Methane emission factors were first calculated by pipe material, as shown in Table C-13. A gathering pipeline average CH_4 emission factor was then derived as shown in Table C-14. Emission factors for CO_2 from pipeline oxidation and pipeline leaks were calculated using Equations 7-13 and 7-14, respectively. Similar to the derivation of the pipeline CH_4 emission factors, CO_2 emission factors were first derived by pipe material, as shown in Table C-15. Average CO_2 emission factors for oxidation and pipeline leaks were then derived from the factors by pipe material, as shown in Table C-16.

Table C-13. Derivation of Fugitive CH_4 Emission Factors for Natural Gas Gathering Pipelines, by Pipe Material [a]

Pipe Material	CH_4 Emission Factor [b,c] (scf/leak-yr)	Activity Factor [b,c] (e.q. leaks)	Annual CH_4 Emissions [d] (Bscf CH_4/yr)	Pipeline Miles [b,c,e]	Emission Factor [f] (scf CH_4/mi-yr)	Emission Factor [f] (lb CH_4/mi-yr)
Cast Iron [g]			0.172 ± 77.7%	856 ± 10%	201,418 ± 77.0%	8,518 ± 77.0%
Plastic	84,237 ± 212 %	6,467 ± 97.0%	0.545 ± 233%	29,862 ± 10%	18,243 ± 233%	771.5 ± 233%
Protected Steel	17,102 ± 103%	53,657 ± 92.3%	0.918 ± 138%	268,082 ± 10%	3,423 ± 139%	144.8 ± 139%
Unprotected Steel	43,705 ± 113%	114,655 ± 92.1%	5.01 ± 146%	41,400 ± 10%	121,039 ± 146%	5,119 ± 146%

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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.

[c] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, *Final Report*, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996. The cast iron leak rate was derived from 21 sample measurements, the plastic leak was derived from 6 measurements, the protected steel leak rate was derived from 17 measurements, and the unprotected steal leak rate was derived from 20 measurements. Note that the CH_4 emission factor shown has already been adjusted for soil oxidation.

[d] Annual CH_4 emissions are estimated by multiplying the leak based emission factor by the number of equivalent leaks.

[e] A confidence interval of ± 10% was assumed based on engineering judgment (Campbell, et al., 1996).

[f] The pipeline based CH_4 emission factor is calculated by dividing the annual CH_4 emissions by the miles of pipeline.

[g] For cast iron pipe, the original emission factor and activity factor are presented on a mile basis.

Table C-14. Derivation of Combined Fugitive CH_4 Emission Factor for Natural Gas Gathering Pipelines [a]

Pipe Material	Annual CH_4 Emissions [b] (Bscf CH_4/yr)	Pipeline Miles [c,d,e] (miles)
Cast Iron	0.172 ± 77.7%	856 ± 10%
Plastic	0.545 ± 233%	29,862 ± 10%
Protected Steel	0.918 ± 138%	268,082 ± 10%
Unprotected Steel	5.01 ± 146%	41,400 ± 10%
Total	6.646 ± 113 %	340,200 ± 8.02%
CH_4 Emission Factor		
Emission Factor Development	EF = (6.646 Bscf CH_4/yr) ÷ 340,200 miles = 19,535 scf CH_4/mile	
Gas Gathering Pipeline Fugitive Emission Factor, Converted to lb CH_4/mile	**826 ± 113% lb CH_4/mile**	

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Derived in Table C-16.

[c] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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.

[d] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, *Final Report*, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[e] A confidence interval of ± 10% was assumed based on engineering judgment (Campbell, et al., 1996).

Table C-15. Derivation of Fugitive CO_2 Emission Factors for Natural Gas Gathering Pipelines, by Pipe Material [a]

Pipe Material	CH_4 Emission Factor [b] (lb CH_4/leak-yr)	% Soil Oxidation [c,d,e]	Pre-oxidized CH_4 Emission Factor (lb CH_4/leak-yr)	CO_2 Oxidation Emission Factor (lb CO_2/mi-yr)	CO_2 Leak Emission Factor [f] (lb CO_2/mi-yr)
Cast Iron	8,518 ± 77.0%	40.3% ± 25%	14,267 ± 81.0%	15,808 ± 81.0%	1,878 ± 81.3%
Plastic	771.5 ± 233%	2.0% ± 25%	787.2 ± 234%	43.29 ± 234%	103.6 ± 235%
Protected Steel	144.8 ± 139%	3.0% ± 25%	149.2 ± 141%	12.31 ± 141%	19.64 ± 141%
Unprotected Steel	5,119 ± 146%	1.8% ± 25%	5,212 ± 148%	258.0 ± 148%	686.0 ± 148%

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Converted from scf CH_4/leak-yr to lb CH_4/leak-yr from Table C-16 based on 60°F and 14.7 psia.

[c] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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.

[d] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, *Final Report*, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[e] Uncertainty of the soil oxidation values is assumed to be ± 25% based on engineering judgment (Campbell, et al., 1996).

[f] The default contents for CH_4 and CO_2 in the production segment are 78.8 mole % and 3.78 mole %, respectively, as shown in Table E-4.

Table C-16. Derivation of Combined Fugitive CO_2 Emission Factors for Gas Gathering Pipelines [a]

Pipe Material	CO_2 Oxidation Emission Factor [b] (lb CO_2/mi-yr)	CO_2 Leak Emission Factor [b] (lb CO_2/mi-yr)	Pipeline Miles [c,d,e]	CO_2 Oxidation Emissions (lb CO_2/yr)	CO_2 Leak Emissions (lb CO_2/yr)
Cast Iron	15,808 ± 81.0%	1,878 ± 81.3%	856 ± 10%	13,531,891 ± 81.6%	1,607,429 ± 81.9%
Plastic	43.29 ± 234%	103.6 ± 235%	29,862 ± 10%	1,292,604 ± 233%	3,093,954 ± 235%
Protected Steel	12.31 ± 141%	19.64 ± 141%	268,082 ± 10%	3,299,731 ± 141%	5,265,452 ± 142%
Unprotected Steel	258.0 ± 148%	686.0 ± 148%	41,400 ± 10%	10,679,253 ± 148%	28,401,857 ± 148%
TOTAL			340,200 ± 8.02%	28,803,480 ± 69.8%	38,368,692 ± 113%
CO_2 Emission Factors					
CO_2 Oxidation Fugitive Emission Factor Development	**EF = 28,803,480 lb CO_2/yr ÷ 340,200 miles = 84.7 ± 70.2% lb CO_2/mile-yr**				
CO_2 Leak Fugitive Emission Factor Development	**EF = 38,368,692 lb CO_2/yr ÷ 340,200 miles = 112.8 ± 114% lb CO_2/mile-yr**				

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Dervied in Table C-18.

[c] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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.

[d] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, *Final Report,* GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[e] A confidence interval of ± 10% was assumed based on engineering judgment (Campbell, et al., 1996).

C.3.3 Gas Processing Fugitive Emission Factors

The gas processing fugitive emission factor in Table 7-34 was developed using data from in Appendix A of Volume 2 of the GRI/EPA study (Harrison, et al., 1996). The gas processing factor is based on the total volume of gas processed, and includes emissions from compressors and other fugitives associated with the processing plant. The precision data were calculated using data presented in Volume 8 of the GRI/EPA study (Hummel, et al., 1996). The emission factor was calculated by dividing the sum of the gas processing CH_4 emissions by the total volume of gas processed (DOE, 1993). The factor derivation is presented in Table C-17.

Table C-17. Derivation of Facility and Equipment-Level Fugitive Emission Factors for Gas Processing

Source	U.S. Methane Emissions [a,b], Bscf CH$_4$/yr	Uncertainty [c], (± %)
Gas Processing Plants	2.095	57.3
Reciprocating Compressors	16.73	113
Centrifugal Compressors	5.626	109
Total	24.45	81.6
Activity Data		
Total Gas Processed [d]	24,794.38 Bscf/yr	10
CH$_4$ Emission Factors		
Facility-Level Gas Processing Fugitive Emission Factor Development	EF = (24.45 × 10^9 scf CH$_4$/yr) ÷ (24,704.38 × 10^9 scf gas/yr) × (10^6/MM) = 2,345.6 scf CH$_4$/MMscf	**82.2**
Facility-Level Gas Processing Fugitive Emission Factor, Converted to lb CH$_4$/MMscf gas	**99.2 lb CH$_4$/MMscf** cited in Table 7-34	
Equipment-Level Gas Processing Fugitive Emission Factor Development	EF = (2.095 × 10^9 scf CH$_4$/yr) ÷ (24,704.38× 10^9 scf gas/yr) × (10^6/MM) = 201.02 scf CH$_4$/MMscf cited in Table 7-35	**58.1**
Equipment-Level Gas Processing Fugitive Emission Factor, Converted to lb CH$_4$/MMscf gas	**8.50 lb CH$_4$/MMscf**	

Footnotes and Sources:

[a] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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.

[b] Hummel, K.E., L.M. Campbell, and M.R. Harrison. *Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks*, *Final Report*, GRI-94/0257.25 and EPA-600/R-96-080h. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[c] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[d] EIA, Natural Gas Plant Processing, September 30, 2021. https://www.eia.gov/dnav/ng/NG_PROD_PP_DCU_NUS_A.htm, Data for calendar year 2020.. An uncertainty factor of 10% was assigned based on engineering judgment.

The gas processing plant fugitive emission factor in Table 7-35, which includes fugitive emissions from sources other than compressors, was developed using data from Appendix A of Volume 2 of the GRI/EPA study (Harrison, et al., 1996). The precision data were calculated using data presented in Volume 8 of the GRI/EPA study (Hummel, et al., 1996). The factor derivation is presented below and shown in Table C-17.

Known: Estimated processing plant fugitive methane emissions = 2.095 ± 57.3% Bscf/year (Harrison, et al., Volume 2, 1996), precision at a 95% confidence interval was calculated using data from Hummel, et al., Volume 8, 1996.

Estimated annual gas processed = 16,045.855 Bscf/yr (DOE, 1993). A 10.0% uncertainty value is assumed for the gas processing rate, based on engineering judgment.

The conversion of the gas processing plant emission factor to tonnes CH_4 per volume of gas processed follows:

$$EF = \frac{2.095 \text{ Bscf } CH_4}{16{,}045.855 \text{ Bscf gas processed}} \times \frac{\text{lbmole } CH_4}{379.3 \text{ scf } CH_4} \times \frac{16 \text{ lb } CH_4}{\text{lbmole } CH_4} \times \frac{10^6 \text{ scf}}{\text{MMscf}} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{EF = 2.50E\text{-}03 \pm 58.1\% \text{ tonne } CH_4/\text{MMscf gas processed}}$$

C.3.4 Natural Gas Storage Station Fugitive Emission Factor

The natural gas storage station fugitive emission factor presented in Table 7-45 was developed using data presented in Appendix A of Volume 2 of the GRI/EPA study (Harrison, et al., 1996). The storage emission factor is presented on a station basis, and includes fugitive emissions associated with the station itself, as well as storage wells and compressors. The emission factor was calculated by dividing the sum of the gas storage station CH_4 emissions by the total number of storage stations. The precision data were calculated using data presented in Volume 8 of the GRI/EPA study (Hummel, et al., 1996). The factor derivation is presented in Table C-18.

Table C-18. Derivation of Facility-Level Average Natural Gas Storage Station Fugitive Emission Factor

Source	U.S. Methane Emissions [a,b], Bscf CH_4/yr	Uncertainty [c], ± (%)
Storage Stations	3.7288	132
Storage Reciprocating Compressors	10.7594	104
Storage Centrifugal Compressors	1.5176	164
Storage Wells	0.7522	76.3
Total	16.7580	74.5
Activity Data		
Total Storage Stations (Count) [d]	475	5
CH_4 Emission Factor		
Emission Factor Development	EF = (16.7580 × 10^9 scf CH_4/yr) ÷ (475 stations) = 35.28 × 10^6 scf CH_4/station-yr	**74.7%**
Gas Storage Station Fugitive Emission Factor, Converted to lb CH_4/station-yr	**1,491,936 lb CH_4/station-yr**	

Footnotes and Sources:

[a] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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.

[b] Hummel, K.E., L.M. Campbell, and M.R. Harrison. *Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks*, *Final Report*, GRI-94/0257.25 and EPA-600/R-96-080h. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[c] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[d] An uncertainty factor of 5% was assigned based on engineering judgment.

C.3.5 Gas Transmission Fugitive Emission Factors

The facility-level average gas transmission pipeline CH_4 fugitive emission factor presented in Table 7-45 was developed using emissions data presented in Appendix A of Volume 2 of the GRI/EPA study (Harrison, et al., 1996). The transmission facility-level average emission factor is based on CH_4 emissions from all identified fugitive sources present in the segment. The CH_4 emission factor was calculated by dividing the total transmission segment CH_4 emissions by the number of transmission pipeline miles. Pipeline miles were taken from Volume 9 of the GRI/EPA report (Campbell, et al, 1996). The precision data were calculated using data presented in Volume 8 of the GRI/EPA study (Hummel, et al., 1996) and Volume 10 of the GRI/EPA study (Campbell, et al., 1996). The factor derivation is presented in Table C-19.

Table C-19. Derivation of Facility-Level Average Fugitive CH_4 Emission Factor for Gas Transmission Pipelines

Source	**U.S. Methane Emissions [a,b,c,d], Bscf CH_4/yr**	**Uncertainty [e], (± %)**
Pipeline Leaks [f]	0.1614	94.2
Transmission Compressor Stations [g]	5.4467	127
Trans. Reciprocating Compressors	37.6787	88.7
Trans. Centrifugal Compressors	7.5302	58.0
Farm Taps and Direct Sales	0.8271	1,390
Transmission Interconnects	3.6834	1,380
Total	55.3274	113
Activity Data		
Total Transmission Pipeline Miles [f]	295,105	9.73
Methane Emission Factor		
Emission Factor Development	EF = (55.3274 × 10^9 scf CH_4/yr) ÷ (295,105 miles) = 187,484 scf CH_4/station-yr	**113**
Transmission Fugitive Emission Factor, Converted to lb CH_4/station-yr	**7,928 lb CH_4/mile-yr**	

Footnotes and Sources:

[a] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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.

[b] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, *Final Report*, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[c] Hummel, K.E., L.M. Campbell, and M.R. Harrison. *Methane Emissions from the Natural Gas Industry*, *Volume 8: Equipment Leaks*, *Final Report*, GRI-94/0257.25 and EPA-600/R-96-080h. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[d] U.S. Department of Transportation (DOT). *Research and Special Programs Administration*, 1991.

[e] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[f] Total shown in Table C-24.

[g] Because the data used to calculate the reference emission was unavailable, the precision at a 95% confidence interval was calculated based on the precision at a 90% confidence interval presented in the source assuming a data set size of ten.

The facility-level average natural gas transmission pipeline CO_2 emission factors were derived in conjunction with the equipment-level gas transmission pipeline CO_2 emission factor; the gas transmission pipeline CO_2 facility-level factor derivation is discussed later in this subsection.

The equipment-level average gas transmission pipeline CH_4 fugitive emission factor presented in Table 7-46 was developed using emissions data presented in Appendix A of Volume 2 of the GRI/EPA study (Harrison, et al., 1996). Emission factors were calculated in the same manner as for gas gathering pipelines. Methane emissions (and corresponding emission factors) were first calculated by pipe material, as shown in Table C-20. A transmission pipeline average CH_4 emission factor was then derived, as shown in Table C-21. Similar to the derivation of the pipeline CH_4 emission factors, CO_2 emission factors were first derived by pipe material, as shown in Table C-22. Average CO_2 emission factors for oxidation and pipeline leaks were then derived from the factors by pipe material, as shown in Table C-23. Methane and CO_2 emission factors by transmission pipe type are also shown in Table 7-64. The precision data was calculated using data presented in Volume 9 of the GRI/EPA study (Campbell, et al., 1996).

Table C-20. Derivation of Detailed Equipment-Level Fugitive CH_4 Emission Factors for Gas Transmission Pipelines, by Pipe Material [a]

Pipe Material	**CH_4 Emission Factor [b,c] (scf/leak-yr)**	**Activity Factor [b,c] (e.q. leaks)**	**Annual CH_4 Emissions [d] (Bscf CH_4/yr)**	**Pipeline Miles [c,e,f] (miles)**	**CH_4 Emission Factor [g] (scf CH_4/mi-yr)**	**CH_4 Emission Factor (lb CH_4/mi-yr)**
Cast Iron [h]			0.0229 ± 77.7%	96 ± 10%	238,736 ± 77.0%	10,096 ± 77.0%
Plastic	99,845 ± 212%	14 ± 97.0%	0.00140 ± 233%	2,621 ± 10%	533.3 ± 233%	22.55 ± 233%
Protected Steel	20,270 ± 103%	5,077 ± 92.3%	0.103 ± 138%	287,155 ± 10%	358.4 ± 139%	15.16 ± 139%
Unprotected Steel	51,802 ± 113%	659 ± 92.1%	0.0341 ± 146%	5,233 ± 10%	6524 ± 146%	275.9 ± 146%

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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.

[c] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, *Final Report*, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996. The cast iron leak rate was derived from 21 sample measurements, the plastic leak was derived from 6 measurements, the protected steel leak rate was derived from 17 measurements, and the unprotected steal leak rate was derived from 19 measurements. Note that the CH_4 emission factor shown has already been adjusted for soil oxidation.

[d] Annual CH_4 emissions are estimated by multiplying the leak based emission factor by the number of equivalent leaks.

[e] U.S. Department of Transportation (DOT). Research and Special Programs Administration, 1991.

[f] A confidence interval of ±10% was assumed based on engineering judgment in the 1991 DOT RSPA database (Campbell, et al., 1996).

[g] The pipeline based methane emission factor is calculated by dividing the annual methane emissions by the miles of pipeline.

[h] For cast iron pipe, the original emission factor and activity factor are presented on a mile basis.

Table C-21. Derivation of Equipment-Level Gas Transmission Pipeline Fugitive CH_4 Emission Factor [a]

Pipe Material	Annual CH_4 Emissions [b] (Bscf CH_4/yr)	Pipeline Miles [c,d] (miles)
Cast Iron [e]	0.0229 ± 77.7%	96 ± 10%
Plastic	0.0014 ± 233%	2,621 ± 10%
Protected Steel	0.103 ± 138%	287,155 ± 10%
Unprotected Steel	0.0341 ± 146%	5,233 ± 10%
Total	0.1614 ± 94.2%	295,105 ± 9.73%
Emission Factor Development	EF = (0.1614 Bscf CH_4/yr) / 295,105 miles = 546.8 scf CH_4/mile	
Gas Transmission Pipeline Fugitive Emission Factor, Converted to lb CH_4/mile	**23.12 ± 94.7% lb CH_4/mile**	

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Derived in Table C-23.

[c] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines, Final Report*, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[d] U.S. Department of Transportation (DOT). Research and Special Programs Administration, 1991. A confidence interval of ±10% was assumed based on engineering judgment in the 1991 DOT RSPA database (Campbell, et al., 1996).

[e] For cast iron pipe, the original emission factor and activity factor are presented on a mile basis.

Equipment-level average emission factors for CO_2 from pipeline oxidation and pipeline leaks were calculated using Equations 7-13 and 7-14, respectively.

Table C-22. Derivation of Fugitive CO_2 Emission Factors for Gas Transmission Pipelines, by Pipe Material [a]

Pipe Material	CH_4 Emission Factor [b] (lb CH_4/leak-yr)	% Soil Oxidation [c,d,e]	Pre-oxidized CH4 Emission Factor (lb CH4/leak-yr)	CO_2 Oxidation Emission Factor (lb CO_2/mi-yr)	CO_2 Leak Emission Factor [f] (lb CO_2/mi-yr)
Cast Iron	10,096 ± 77.0%	40.3% ± 25%	16,911 ± 81.0%	18,699 ± 81.0%	993.6 ± 81.1%
Plastic	22.55 ± 233%	2.0% ± 25%	23.01 ± 234%	1.263 ± 234%	1.352 ± 234%
Protected Steel	15.16 ± 139%	3.0% ± 25%	15.62 ± 141%	1.286 ± 141%	0.9180 ± 141%
Unprotected Steel	275.9 ± 146%	1.8% ± 25%	280.9 ± 148%	13.87 ± 148%	16.51 ± 148%

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Derived in Table C-23.

[c] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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.

[d] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, *Final Report*, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[e] The precision of the soil oxidation values is assumed to be ± 25% based on engineering judgment (Campbell, et al., 1996).

[f] The default contents for CH_4 and CO_2 in the transmission segment are 93.4 mole % and 2.0 mole %, respectively, as shown in Table E-4.

Table C-23. Derivation of Equipment-Level Average Fugitive CO_2 Emission Factors for Gas Transmission Pipelines [a]

Pipe Material	Annual CO_2 Oxidation Emission [b] (lb CO_2/mi-yr)	Annual CO_2 Leak Emissions [b] (lb CO2/mi-yr)	Pipeline Miles [c,d] (miles)	Annual CO_2 Oxidation Emissions (lb CO_2/yr)	Annual CO_2 Leak Emission (lb CO_2/yr)
Cast Iron	18,699 ± 81.0%	993.6 ± 81.1%	96 ± 10%	1,795,099 ± 81.6%	95,382 ± 81.7%
Plastic	1.263 ± 234%	1.352 ± 234%	2,621 ± 10%	3,310 ± 235%	3,543 ± 235%
Protected Steel	1.286 ± 141%	0.9180 ± 141%	287,155 ± 10%	369,300 ± 141%	263,597 ± 141%
Unprotected Steel	13.87 ± 148%	16.51 ± 148%	5,233 ± 10%	72,604 ± 148%	86,372 ± 148%
Total			295,105 ± 9.73%	2,240,313 ± 69.6%	448,895 ± 89.6%
CO_2 Oxidation Fugitive Emission Factor Development	**2,240,313 lb CO_2/yr ÷ 295,105 miles = 7.59 ± 70.3% lb CO_2/mile-yr**				
CO_2 Leak Fugitive Emission Factor Development	**448,895 lb CO_2/yr ÷ 295,105 miles = 1.52 ± 90.1% lb CO_2/mile-yr**				

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Derived in Table C-25.

[c] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, *Final Report*, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[d] U.S. Department of Transportation (DOT). Research and Special Programs Administration, 1991. A confidence interval of ±10% was assumed based on engineering judgment in the 1991 DOT RSPA database (Campbell, et al., 1996).

The derivation of the facility-level average gas transmission pipeline CO_2 emission factor for CO_2 from pipeline leaks (as shown in Table 7-45) is shown in Table C-24. The factor was developed using emissions data presented in Appendix A of Volume 2 of the GRI/EPA study (Harrison, et al., 1996). The factor is calculated in three steps: first, by first subtracting the pipeline leak emissions from the total transmission emissions (calculated in Table C-19); second, by dividing the result by the transmission pipeline miles (calculated in Table C-23); and third, by adding the equipment-level average CO_2 leak emission factor derived in Table C-23. Note that the reason that the pipeline leak emissions have to be considered separately is that the pipeline leak emissions shown in Table C-19 take into account soil oxidation effects associated with buried pipelines. Therefore, the pipeline leak emissions cannot be converted directly from the CH_4 leak emission factor as shown for the rest of the transmission segment emissions.

Table C-24. Derivation of Facility-Level Average Gas Transmission Pipeline Fugitive CO_2 Leak Emission Factor

Source	U.S. Methane Emissions, Bscf CH_4/yr	Uncertainty [a], ± (%)
Total Transmission Emissions [b]	55.3274	113
Pipeline Leaks [c]	0.1614	94.2
Adjusted Transmission Emissions	55.166	113
Activity Data		
Total Transmission Pipeline Miles [d]	295,105	9.73
CO_2 Emission Factor		
CH_4 Emission Factor Development	EF = (55.2×10^9 scf CH_4/yr) / (295,105 miles) = 186,937 scf CH_4/station-yr	113
Transmission Fugitive Emission Factor, converted to lb CH_4/mile-yr	7,905 lb CH_4/mile-yr	
Equipment-Level CO_2 Leak Fugitive Emission Factor Development	1.52 lb CO_2/mile-yr (Derived in Table C-26)	93.2
CO_2 Leak Emission Factor Development	EF = (7,905 lb CH_4/mile-yr) × (lbmole CH_4/16 lb CH_4) × (lbmol gas/0.934 lbmole CH_4) × (0.02 lbmol CO_2/lbmol gas) × (44 lb CO_2/lbmol CO_2) = 464.46 lb CO_2/mile-yr + 1.52 lb CO_2/mile-yr	
Transmission Fugitive CO_2 Leak Emission Factor, lb CO_2/mile-yr	**466.0 lb CO_2/mile-yr**	**113**

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Derived in Table C-22.

[c] Derived in Table C-24.

[d] Total shown in Table C-26.

The gas transmission meter/regulator (M&R) station fugitive CH_4 emission factor presented in Table 7-46 was developed using emissions data presented in Appendix A of Volume 2 of the GRI/EPA study (Harrison, et al., 1996). This emission factor combines the transmission interconnect and farm tap/direct sales M&R emission and activity data. The precision data were calculated using data presented in Volume 10 of the GRI/EPA study (Campbell, et al., 1996). The factor development is presented in Table C-25.

Table C-25. Derivation of M&R Stations Fugitive CH_4 Emission Factor

Source	U.S. Methane Emissions [a,b], Bscf CH_4/yr	Uncertainty [c], (± %)
Farm Taps and Direct Sales	0.8271	1390 [d]
Transmission Interconnects	3.6834	1380 [e]
Total	4.5105	1150 [f]
Activity Data		
Farm Tap and Direct Sale Stations (Count)	72,629	991
Transmission Interconnect Stations (Count)	2533	990
Total M&R Stations Count	75,162	958
CH_4 Emission Factor		
Emission Factor Development	EF = (4.5105 × 10^9 scf CH_4/yr) ÷ (75,162 stations)	**1,500 [g]**
M&R Station Fugitive Emission Factor, scf CH_4/station-yr	**60,011 scf CH_4/station-yr**	

Footnotes and Sources:

[a] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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.

[b] Campbell, L.M. and B.E. Stapper. *Methane Emissions from the Natural Gas Industry*, *Volume 10: Metering and Pressure Regulating, Stations in Natural Gas, and Transmission and Distribution, Final Report*, GRI-94/0257.27 and EPA-600/R-96-080j. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[c] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[d] Uncertainty range (0 – 11.5 Bscf CH_4/yr)

[e] Uncertainty range (0 – 50.8 Bscf CH_4/yr)

[f] Uncertainty range (0 – 52.3 Bscf CH_4/yr)

[g] Uncertainty range (0 – 900,158 scf CH_4/station-yr)

C.3.6 Gas Distribution Fugitive Emission Factors

The facility-level average gas distribution pipeline CH_4 fugitive emission factor presented in Table 6-2 was developed using emissions data presented in Appendix A of Volume 2 of the GRI/EPA study (Harrison, et al., 1996). The CH_4 emission factor is based on CH_4 emissions from all identified fugitive emission sources in the segment. The factor was calculated by dividing the total distribution segment CH_4 emissions by the number of transmission pipeline miles. Pipeline miles were taken from Volume 9 of the GRI/EPA report (Campbell, et al, 1996). The uncertainty data were calculated using data presented in Volume 8 of the GRI/EPA study (Hummel, et al.,

1996) and Volume 9 of the GRI/EPA study (Campbell, et al., 1996). The factor derivation is presented in Table C-26.

Table C-26. Derivation of Facility-Level Average Fugitive CH_4 Emission Factor for Gas Distribution Pipelines

Source	U.S. Methane Emissions [a,b,c], Bscf CH_4/yr	Uncertainty [d], ± (%)
Pipeline Mains - Cast Iron	13.1992	77.5
Pipeline Mains - Unprotected Steel	9.0476	159
Pipeline Mains - Protected Steel	1.3846	154
Pipeline Mains - Plastic	4.9150	411
Services - Unprotected Steel	9.2630	259
Services - Protected Steel	3.5922	225
Services - Plastic	0.1644	332
Services - Copper	0.0593	215
M&R Station [e]	27.3202	105
Residential Meters	5.5468	23.7
Commercial/Industrial Meters	0.2207	47.5
Total	74.7131	62.6
Activity Data		
Total Main Pipeline Miles [f]	888,284	3.10
CH_4 Emission Factor		
Emission Factor Development	EF = (74.7130 × 10^9 scf CH_4/yr) ÷ (888,284 miles) = 84,110 scf CH_4/mile-yr	**62.7**
Gas Distribution Pipeline Fugitive Emission Factor, Converted to lb CH_4/ mile-yr	**3,557 lb CH_4/mile-yr**	

Footnotes and Sources:

[a] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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.

[b] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, *Final Report*, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[c] Hummel, K.E., L.M. Campbell, and M.R. Harrison. *Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks*, *Final Report*, GRI-94/0257.25 and EPA-600/R-96-080h. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[d] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[e] M&R station total emissions are based on the sum of emissions from the 10 M&R station categories presented in Table C-41.

[f] Total distribution main miles are taken from Table C-31.

The facility-level average gas transmission pipeline CO_2 emission factor derivations were derived in conjunction with the equipment-level gas distribution pipeline and gas distribution service CO_2 emission factors. The CO_2 facility-level factor derivation is discussed later in this subsection.

The equipment-level average gas distribution pipeline CH_4 fugitive emission factor presented in Table 7-63 was developed using emissions data presented in Appendix A of Volume 2 of the GRI/EPA study (Harrison, et al., 1996). Emission factors were calculated in the same manner as for gas transmission pipelines. Methane emissions (and corresponding emission factors) were first calculated by pipe material, as shown in Table C-27. A distribution pipeline average CH$_4$ emission factor was then derived, as shown in Table C-28. Equipment-level average emission factors for CO$_2$ from pipeline oxidation and pipeline leaks were calculated using Equations 7-13 and 7-14, respectively.

Table C-27. Derivation of Equipment-Level Fugitive CH$_4$ Emission Factors for Gas Distribution Mains, by Pipe Material [a]

Pipe Material	CH$_4$ Emission Factor [b,c] (scf/leak-yr)	Activity Factor [b,c] (e.q. leaks)	Annual CH$_4$ Emissions [d] (Bscf CH$_4$/yr)	Pipeline Miles [b,c,e] (miles)	CH$_4$ Emission Factor [f] (scf CH$_4$/mi-yr)	CH$_4$ Emission Factor (lb CH$_4$/mi-yr)
Cast Iron [g]			13.199 ± 77.2%	55,288 ± 5%	238,736 ± 77.0%	10,096 ± 77.0%
Plastic	99,845 ± 212%	49,226 ± 151%	4.915 ± 260%	299,421 ± 5%	16,415 ± 260%	694.2 ± 260%
Protected Steel	20,270 ± 103%	68,308 ± 75.3%	1.385 ± 128%	451,466 ± 5%	3,067 ± 128%	129.7 ± 128%
Unprotected Steel	51,802 ± 113%	174,657 ± 70.3%	9.048 ± 133%	82,109 ± 5%	110,190 ± 133%	4,660 ± 133%

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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.

[c] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, *Final Report*, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996. The cast iron leak rate was derived from 21 sample measurements, the plastic leak was derived from 6 measurements, the protected steel leak rate was derived from 17 measurements, and the unprotected steal leak rate was derived from 20 measurements. Note that the CH$_4$ emission factor shown has already been adjusted for soil oxidation.

[d] Annual CH$_4$ emissions are estimated by multiplying the leak based emission factor by the number of equivalent leaks.

[e] A confidence interval of ± 5% was assumed based on engineering judgment (Campbell,et al., 1996).

[f] The pipeline based methane emission factor is calculated by dividing the annual methane emissions by the miles of pipeline.

[g] For cast iron pipe, the original emission factor and activity factor are presented on a mile basis.

Table C-28. Derivation of Equipment-Level Average Fugitive CH$_4$ Emission Factor for Gas Distribution Mains [a]

Pipe Material	Annual CH$_4$ Emissions (Bscf CH$_4$/yr) [b,c]	Pipeline Miles (miles) [d,e,f]
Cast Iron	13.199 ± 77.2%	55,288[e] ± 5%
Plastic	4.915 ± 260%	299,421 ± 5%
Protected Steel	1.385 ± 128%	451,466 ± 5%
Unprotected Steel	9.048 ± 133%	82,109 ± 5%
Total	28.546 ± 71.3 %	888,284 ± 3.10%
Emission Factor Development	EF = (28.546×10^9 scf CH$_4$/yr) ÷ 888,284 miles = 32,137 scf CH$_4$/mile	
Gas Pipeline Emission Factor, Converted to lb CH$_4$/mile	**1,359 ± 71.4% lb CH$_4$/mile**	

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Derived in Table C-30.

[c] Annual CH$_4$ emissions are estimated by multiplying the leak based emission factor by the number of equivalent leaks.

[d] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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.

[e] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines, Final Report*, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[f] A confidence interval of ± 5% was assumed based on engineering judgment (Campbell, et al., 1996).

Similar to the derivation of the pipeline CH$_4$ emission factors, CO$_2$ emission factors were first derived by pipe material, as shown in Table C-29. Average CO$_2$ emission factors for oxidation and pipeline leaks were then derived from the factors by pipe material, as shown in Table C-30. Methane and CO$_2$ emission factors by distribution pipe type are also shown in Table 7-63. The precision data were calculated using data presented in Volume 9 of the GRI/EPA study (Campbell, et al., 1996).

Table C-29. Derivation of Fugitive CO$_2$ Emission Factors for Gas Distribution Mains, by Pipe Material [a]

Pipe Material	CH$_4$ Emission Factor [b] (lb CH$_4$/leak-yr)	% Soil Oxidation [c,d,e]	Pre-oxidized CH$_4$ Emission Factor (lb CH$_4$/leak-yr)	CO$_2$ Oxidation Emission Factor (lb CO$_2$/mi-yr)	CO$_2$ Leak Emission Factor [f] (lb CO$_2$/mi-yr)
Cast Iron	10,096 ± 77.0%	40.3% ± 25%	16,911 ± 81.0%	18,699 ± 81.0%	993.6 ± 81.1%
Plastic	694.2 ± 260%	2.0% ± 25%	708.3 ± 261%	38.87 ± 261%	41.62 ± 261%
Protected Steel	129.7 ± 128%	3.0% ± 25%	133.7 ± 130%	11.01 ± 130%	7.856 ± 130%
Unprotected Steel	4,660 ± 133%	1.8% ± 25%	4,745 ± 135%	234.4 ± 135%	278.8 ± 135%

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Derived in Table C-30.

[c] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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.

[d] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, *Final Report*, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[e] The uncertainty of the soil oxidation values is assumed to be ± 25% based on engineering judgment (Campbell, et al., 1996).

[f] The default contents for CH$_4$ and CO$_2$ in the distribution segment are 93.4 mole % and 2.0 mole %, respectively, as shown in Table E-4.

Table C-30. Derivation of Equipment-Level Average Fugitive CO_2 Emission Factor for Gas Distribution Mains [a]

Pipe Material	Annual CO_2 Oxidation Emission Factor [b] (lb CO_2/mi-yr)	Annual CO_2 Leak Emission Factor [b] (lb CO_2/mi-yr)	Pipeline Miles [c,d,e] (miles)	Annual CO_2 Oxidation Emissions (lb CO_2/yr)	Annual CO_2 Leak Emissions (lb CO_2/yr)
Cast Iron	18,699 ± 81.0%	994 ± 81.1%	55,288 ± 5%	1,033,827,389 ± 81.1%	54,932,088 ± 81.3%
Plastic	38.9 ± 261%	41.6 ± 261%	299,421 ± 5%	11,638,401 ± 261%	12,460,815 ± 261%
Protected Steel	11.0 ± 130%	7.86 ± 130%	451,466 ± 5%	4,968,707 ± 130%	3,546,543 ± 130%
Unprotected Steel	234.4 ± 135%	278.8 ± 135%	82,109 ± 5%	19,242,525 ± 135%	22,891,417 ± 135%
Total			888,284 ± 3.10%	1,069,677,022 ± 78.5%	93,830,863 ± 67.7%
CO_2 Oxidation Fugitive Emission Factor Development	**1,069,677,022 lb CO_2/yr ÷ 888,284 miles =1,204 ± 78.6% lb CO_2/mile-yr**				
CO_2 Leak Fugitive Emission Factor Development	**93,830,863 lb CO_2/yr ÷ 888,284 miles =105.6 ± 67.7% lb CO_2/mile-yr**				

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Derived in Table C-32.

[c] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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.

[d] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, *Final Report*, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[e] A confidence interval of ± 5% was assumed based on engineering judgment (Campbell, et al., 1996).

The equipment-level average gas distribution service CH_4 fugitive emission factor presented in Table 7-63 was developed using emissions data presented in Appendix A of Volume 2 of the GRI/EPA study (Harrison, et al., 1996). Emission factors were calculated in the same manner as for gas distribution pipelines, except emission factors are estimated by dividing the emissions by pipeline services instead of pipeline miles.

Methane emissions (and corresponding emission factors) were first calculated by pipe material, as shown in Table C-31. A distribution service average CH_4 emission factor was then derived, as shown in Table C-32. The average factor was converted from a service basis to a mileage basis by scaling the EPA/GRI study service count to miles using 1992 pipeline statistics from the U.S. Department of Transportation, Research and Special Programs Administration website (Volume 9, Campbell, et al., 1996).

Table C-31. Derivation of Detailed Fugitive CH_4 Emission Factors for Gas Distribution Services, by Pipe Material [a]

Pipe Material	CH_4 Emission Factor [b,c] (scf/leak-yr)	Activity Factor [b,c] (e.q. leaks)	Annual CH_4 Emissions [d] (Bscf CH_4/yr)	Services [b,c,e] (Count)	CH_4 Emission Factor [f] (scf CH_4/ service-yr)	CH_4 Emission Factor (lb CH_4/ service-yr)
Copper	7,684 ± 94.2%	7,720 ± 144%	0.0593 ± 172%	233,246 ± 5%	254.3 ± 172%	10.76 ± 172%
Plastic	2,386 ± 193%	68,903 ± 131%	0.1644 ± 234%	17,681,238 ± 5%	9.298 ± 234%	0.3932 ± 234%
Protected Steel	9,196 ± 73.3%	390,628 ± 163%	3.592 ± 178%	20,352,983 ± 5%	176.5 ± 178%	7.464 ± 178%
Unprotected Steel	20,204 ± 128%	458,476 ± 133%	9.263 ± 185%	5,446,393 ± 5%	1,701 ± 185%	71.92 ± 185%

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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.

[c] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, *Final Report*, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996. The copper leak rate was derived from 5 sample measurements, the plastic leak was derived from 4 measurements, the protected steel leak rate was derived from 24 measurements, and the unprotected steal leak rate was derived from 13 measurements. Note that the CH_4 emission factor shown has already been adjusted for soil oxidation.

[d] Annual CH_4 emissions are estimated by multiplying the leak based emission factor by the number of equivalent leaks.

[e] A confidence interval of ± 5% was assumed based on engineering judgment (Campbell, et al., 1996).

[f] The pipeline service based methane emission factor is calculated by dividing the annual CH_4 emissions by the number of services.

Table C-32. Derivation of Equipment-Level Average Fugitive CH_4 Emission Factor for Gas Distribution Services [a]

Pipe Material	Annual CH_4 Emissions [b] (Bscf CH_4/yr)	Pipeline Services [c,d,e]
Copper	0.0593 ± 172%	233,246 ± 5%
Plastic	0.1644 ± 234%	17,681,238 ± 5%
Protected Steel	3.592 ± 178%	20,352,983 ± 5%
Unprotected Steel	9.263 ± 185%	5,446,393 ± 5%
TOTAL	**13.08 ± 140%**	**43,713,860 ± 3.15%**
Gas Distribution Service Fugitive CH_4 Emission Factor Development (service basis)	EF = (13.08 Bscf CH4/yr) ÷ 43,713,860 services = 299.2 scf CH_4/service-yr	
Gas Distribution Service Fugitive CH_4 Emission Factor (service basis), Converted to lb CH_4/service-yr	**12.65 ± 140% lb CH_4/service-yr**	
Gas Distribution Service Fugitive CH_4 Emission Factor Development (mileage basis)	Activity Factor	
	518,335 ± 5.00%	miles [f]
	EF = (13.08 Bscf CH_4/yr) ÷ 518,335 miles = 25,233 scf CH_4/mile-yr	
Gas Distribution Service Fugitive CH_4 Emission Factor (mileage basis), Converted to lb CH_4/services-yr	**1,067 ± 140% lb CH_4/mile-yr**	

Footnotes and Sources for Table C-35:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Derived in Table C-34.

[c] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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.

[d] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines, Final Report*, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[e] A confidence interval of ± 5% was assumed based on engineering judgment (Campbell, et al., 1996).

[f] 1992 pipeline statistics from U.S. Department of Transportation (DOT) Research and Special Programs Administration (RSPA).

Equipment-level average emission factors for CO_2 from pipeline oxidation and pipeline leaks were calculated using Equations 7-13 and 7-14, respectively. Similar to the derivation of the pipeline CH_4 emission factors, CO_2 emission factors were first derived by pipe material, as shown in Table C-33. Average CO_2 emission factors for oxidation and pipeline leaks were then derived from the factors by pipe material, as shown in Table C-34. Methane and CO_2 emission factors by distribution pipe type are also shown in Table 7-47. The precision data were calculated using data presented in Volume 9 of the GRI/EPA study (Campbell, et al., 1996).

Table C-33. Derivation of Fugitive CO_2 Emission Factors for Gas Distribution Services, by Pipe Material [a]

Pipe Material	CH_4 Emission Factor [b] (lb CH_4/leak-yr)	% Soil Oxidation [c,d,e]	Pre-oxidized CH_4 Emission Factor (lb CH4/leak-yr)	CO_2 Oxidation Emission Factor (lb CO_2/service-yr)	CO_2 Leak Emission Factor [f] (lb CO_2/service-yr)
Copper	10.76 ± 172%	0%	10.76 ± 174%	0	0.6319 ± 174%
Plastic	0.3932 ± 234%	21.2% ± 25%	0.4990 ± 235%	0.2903 ± 235%	0.02932 ± 235%
Protected Steel	7.464 ± 178%	2.6% ± 25%	7.663 ± 180%	0.5467 ± 180%	0.4502 ± 180%
Unprotected Steel	71.92 ± 185%	1.1% ± 25%	72.72 ± 186%	2.195 ± 186%	4.273 ± 186%

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Derived in Table C-34.

[c] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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.

[d] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines, Final Report,* GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[e] The precision of soil oxidation is assumed to be ±25% based on engineering judgment (Campbell, et al., 1996).

[f] The default contents for CH_4 and CO_2 in the distribution segment are 93.4 mole% and 2.0 mole%, respectively, as shown in Table E-4.

Table C-34. Derivation of Equipment-Level Average Fugitive CO_2 Emission Factor for Gas Distribution Services [a]

Pipe Material	**CO_2 Oxidation Emission Factor [b] (lb CO_2/service-yr)**	**CO_2 Leak Emission Factor [b] (lb CO_2/service-yr)**	**Pipeline Services [c,d,e] (Count)**	**CO_2 Oxidation Emissions (lb CO_2/yr)**	**CO_2 Leak Emissions (lb CO_2/yr)**
Copper	0	0.6319 ± 174%	233,246 ± 5%	0	147,386 ± 174%
Plastic	0.2903 ± 235%	0.02932 ± 235%	17,681,238 ± 5%	5,132,001 ± 235%	518,363 ± 235%
Protected Steel	0.5467 ± 180%	0.4502 ± 180%	20,352,983 ± 5%	11,126,159 ± 180%	9,163,366 ± 180%
Unprotected Steel	2.195 ± 186%	4.273 ± 186%	5,446,393 ± 5%	11,954,155 ± 187%	23,270,693 ± 187%
Total			43,713,860 ± 3.15%	28,212,315 ± 115%	33,099,808 ± 140%
CO_2 Emission Factors (Service Basis)					
CO_2 Oxidation Fugitive Emission Factor Development	**28,212,315 lb CO_2/yr ÷ 43,713,860 services = 0.65 ± 115% lb CO_2/mile-yr**				
CO_2 Leak Fugitive Emission Factor Development	**33,099,808 lb CO_2/yr ÷ 43,713,860 services = 0.76 ± 140% lb CO_2/mile-yr**				
CO_2 Emission Factors (Mileage Basis)					
Activity Data					
Service Miles [d]	518,335 ±5% miles				
CO_2 Oxidation Fugitive Emission Factor Development	**28,212,315 lb CO_2/yr ÷ 518,335 miles of services = 54.4 ± 115% lb CO_2/mile-yr**				
CO_2 Leak Fugitive Emission Factor Development	**33,099,808 lb CO_2/yr ÷ 518,335 miles of services = 63.9 ± 140% lb CO_2/mile-yr**				

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Derived in Table C-36.

[c] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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.

[d] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines, Final Report*, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[e] A confidence interval of ± 5% was assumed based on engineering judgment (Campbell, 1996).

The facility-level average CO_2 emission factors for gas distribution pipelines are derived in Table C-35. The facility-level average CO_2 emission factor for distribution pipeline leak oxidation is calculated by combining the emission contributions from distribution main pipelines and services and dividing by the total distribution pipeline miles. Carbon dioxide emissions from distribution pipeline leaks originate from pipeline leaks and other process equipment leaks. The CO_2 emission factor for pipeline leaks is calculated in three steps: first, by subtracting the emissions from pipeline mains and services from the total distribution emissions (calculated in Table C-26); second, by dividing by the total main pipeline miles and converting to a mass basis; and third, by adding the pre-oxidized distribution pipeline leak emissions, which are calculated by dividing the sum of the total main pipeline leak emissions (derived in Table C-30) and total distribution service leak emissions (derived in Table C-34) by the total miles of distribution pipeline. Emissions data were taken from Appendix A of Volume 2 of the GRI/EPA study (Harrison, et al., 1996). Pipeline miles were taken from Volume 9 of the GRI/EPA report (Campbell, et al, 1996). The precision data was calculated using data presented in Volume 9 of the GRI/EPA study (Campbell, et al., 1996). The factor derivations are shown in Table C-35.

Table C-35. Derivation of Facility-Level Average Fugitive CO_2 Emission Factors for Gas Distribution Pipelines

CO_2 From Oxidation		
Source	**U.S. CO_2 Emissions, lb CO_2/yr**	**Uncertainty [a], (± %)**
Total Distribution Mains Emissions [b]	1,069,677,022	78.5
Total Distribution Services Emissions [c]	28,212,315	115
Total	1,097,889,337	76.6
Activity Data		
Total Distribution Pipeline Miles[b]	888,284	3.10
CO_2 From Oxidation Emission Factor		
Emission Factor Development	EF = (1,097,889,337 lb CO_2/yr) ÷ (888,284 miles) =	**76.6**
CO_2 Oxidation Fugitive Emission Factor	**1,236 lb CO_2/mile-yr**	
CO_2 from Leaks		
Source	**U.S. CH_4 Emissions, Bscf CH_4/yr**	**Uncertainty [a], (± %)**
Total Distribution Emissions [d]	74.71	62.7
Total Distribution Mains Emissions [d]	28.55	78.6
Total Distribution Services Emissions [d]	13.08	115
Total	33.0878	163
Activity Data		
Total Distribution Pipeline Miles [b]	888,284	3.10
CO_2 From Leaks Emission Factor		
Emission Factor Development	EF = (33.0878×10^9 scf CH_4/yr) ÷ (888,284 miles) = 37,249 scf CH_4/mile-yr = 1,575 lb CH_4/mile-yr	163

Table C–35. Derivation of Facility-Level Average Fugitive CO_2 Emission Factors for Gas Distribution Pipelines, continued

Source	U.S. CH_4 Emissions, Bscf CH_4/yr	Uncertainty [a], (± %)
CO_2 From Leaks Emission Factor, continued		
Emission Factor Development, continued	EF = (1,575 lb CH_4/mile-yr) × (lbmole CH_4/16 lb CH_4) × (lbmol gas/0.934 lbmole CH_4) × (0.02 lbmol CO_2/lbmol gas) × (44 lb CO_2/lbmol CO_2) = 92.55 lb CO_2/mile-yr	163
	EF = (93,830,863 lb CO_2/yr[b] + 33,099,808 lb CO_2/yr[c]) ÷ (888,284 miles) = 142.9 lb CO_2/mile-yr	62.1
	EF = (92.55 lb CO_2/mile-yr) + (142.9 lb CO_2/mile-yr)	
CO_2 Leak Fugitive Emission Factor	**235.4 lb CO_2/mile-yr**	**74.4**

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Total shown in Table C-33.

[c] Derived in Table C-37.

[d] Total shown in Table C-29.

The customer meter CH_4 fugitive emission factor presented in Table 7-63 was developed using emissions data presented in Appendix A of Volume 2 of the GRI/EPA study (Harrison, et al., 1996). This emission factor represents a combination of the commercial/industrial and residential meter emission factors. The precision data were calculated using data presented in Volume 8 of the GRI/EPA study (Hummel, et al., 1996). The factor derivation is presented in Table C-36.

Table C-36. Derivation of Equipment-Level Fugitive CH_4 Emission Factor for Customer Meters

Source	U.S. Methane Emissions [a,b], Bscf CH_4/yr	Uncertainty [c], ± (%)
Residential Meters	5.5468	23.7
Commercial/Industrial Meters	0.2207	47.5
Total	5.7676	22.9
Activity Data		
Residential Meters (Count) [d]	40,049,306	10
Commercial/Industrial Meters (Count) [e]	4,608,000	5
Total Customer Meters Count	44,657,306	8.98
Methane Emission Factor		
Emission Factor Development	EF = (5.7676 × 10^9 scf CH_4/yr) ÷ (44,657,306 meters) =	**24.6%**
Customer Meter Fugitive CH4 Emission Factor	**129.15 scf CH_4/meters-yr**	

Footnotes and Sources for Table C-39:

[a] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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.

[b] Hummel, K.E., L.M. Campbell, and M.R. Harrison. *Methane Emissions from the Natural Gas Industry*, *Volume 8: Equipment Leaks*, *Final Report*, GRI-94/0257.25 and EPA-600/R-96-080h. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[c] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[d] An uncertainty factor of 10% was assigned based on engineering judgment.

[e] An uncertainty factor of 5% was assigned based on engineering judgment.

The distribution meter/regulating stations fugitive CH_4 emission factor presented in Table 7-63 was developed using emissions data presented in Appendix A of Volume 2 of the GRI/EPA study (Harrison, et al., 1996). The precision data were calculated using data presented in Volume 10 of the GRI/EPA study (Campbell, et al., 1996). The factor derivation is presented in Table C-37.

Table C-37. Derivation of Equipment-Level Fugitive CH_4 Emission Factor for Distribution/Meter Reg. Stations

Source	**U.S. Methane Emissions [a,b], Bscf CH_4/yr**	**Uncertainty [c] (± %)**
M & R > 300 psig	5.451	105
M & R 100-300 psig	11.1731	239
M & R < 100 psig	0.2693	455
Regulating > 300 psig	5.6655	119
R-Vault > 300 psig	0.0266	282
Regulating 100-300 psig	4.352	121
R-Vault 100-300 psig	0.0087	155
Regulating 40-100 psig	0.3317	134
R-Vault 40-100 psig	0.0244	121
Regulating <40 psig	0.0179	213
Total	27.3202	105
Activity Data		
M & R > 300 psig, stations	3,460	87.0
M & R 100-300 psig, stations	13,335	130
M & R < 100 psig, stations	7,127	145
Regulating > 300 psig, stations	3,995	83.3
R-Vault > 300 psig, stations	2,346	83.3
Regulating 100-300 psig, stations	12,273	74.8
R-Vault 100-300 psig, stations	5,514	74.8
Regulating 40-100 psig, stations	36,328	78.4
R-Vault 40-100 psig, stations	32,215	78.4
Regulating <40 psig, stations	15,377	79.7
Total Stations	131,970	35.0
Methane Emission Factor		
Emission Factor Development	EF = (27.3202 × 10^9 scf CH_4/yr) ÷ (131,970 stations) =	**111**
Distribution M&R Station Fugitive Emission Factor	**207,018 scf CH_4/station-yr**	

Footnotes and Sources for Table C-40:
[a] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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.
[b] Campbell, L.M. and B.E. Stapper. *Methane Emissions from the Natural Gas Industry*, *Volume 10: Metering and Pressure Regulating, Stations in Natural Gas, and Transmission and Distribution*, *Final Report*, GRI-94/0257.27 and EPA-600/R-96-080j. Gas Research Institute and U.S. Environmental Protection Agency, June 1996. Emissions are based on data collected from 95 measurements at 12 locations using downwind tracer gas measurements. The number of stations in each inlet pressure/station category were provided by 12 distribution companies.
[c] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

C.3.7 Plastic Pipeline Fugitive Emission Leak Factors

The leak basis plastic pipeline emission factors presented in Table 6-11 were developed using data (six data points) presented in Table A-2 of Volume 9 of the GRI/EPA study (Campbell, et al., 1996) and from seven data points from a SoCal gas "unaccounted for" study (SoCal, 1993), as shown below in Table C-38.

Table C-38. Derivation of Fugitive Emission Leak Factor from Plastic Pipelines by Construction Year

Data Source	Test ID Number	Pre-1982 Gas Leak Rate (scf/leak-hr)	Post-1982 (ASTM D2837) Gas Leak Rate (scf/leak-hr)
1996 GRI/EPA, Volume 9, Table A-2 [a]	2014	0.008	0.008
	3020	0.700	0.700
	3019	1.130	1.130
	3039	1.620	1.620
	11002	10.266	
	2002	61.000	
SoCal Unaccounted Study [b, c]	NA	1.2	1.2
	NA	1.2	1.2
	NA	1.2	1.2
	NA	1.2	1.2
	NA	1.2	1.2
	NA	1.2	1.2
	NA	1.2	1.2
Average Total Gas Leak Rate (scf/leak-hr):		**6.394**	**1.078**

Footnotes and Sources:
[a] Campbell, L. M., M. V. Campbell, and D. L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, *Final Report*, GRI-94/0257.26 and EPA 600/R-96-080i. Gas Research Institute and U. S. Environmental Protection Agency, June 1996.
[b] Southern California Gas Company (SoCal). *A Study of the 1991 Unacconted-for Gas Volume at the Southern Gas Company*, April 1993.
[c] The SoCal data were taken from: California Energy Commission (CEC). Evaluation of Oil and Gas Sector Greenhouse Gas Emissions Estimation and Reporting, California Energy Commission, Consultant Report, Final Draft, April 14, 2006.

All six leak data points from Table A-2 of Volume 9 of the GRI/EPA study and all seven data points from the SoCal data were averaged to develop the pre-1982 plastic pipeline emission factor (i.e., average of the 13 total data points). As shown in Table C-38, data points "11002" and "2002" appear high, and were assumed to reflect the amount of inferior pre-1982 plastic pipelines that may be used. Therefore, these two data points were not included in the dataset used to develop the post-1982 (ASTM 2837) pipeline emission factors (but the other 11 out of 13 data points from the GRI/EPA and SoCal studies were included and assumed to reflect post-1982 plastic pipeline materials of construction).

The leak based emission factors provided in Table C-38 were further converted to a plastic pipeline mileage basis based on the U.S. national equivalent leak/miles ratio taken from data presented in Volume 9 of the 1996 GRI/EPA study. Equivalent leaks and plastic pipeline miles were not provided by year of construction, so this conversion was based on the total U.S. equivalent leaks and miles of plastic pipeline. The converted factors are presented in Table 7-69.

C.3.8 CO_2 Pipeline Fugitive Emissions

Section 7.3.3 cites an IPCC equation to estimate fugitive emissions from the pipeline transport of CO_2, such as for EOR operations, similar to fugitive emissions from the pipeline transport of natural gas. IPCC starts the derivation by characterizing the pressure drop in the pipe using the following formula for any geometry:

$$\Delta P = \frac{f}{2} \rho \, v^2 \frac{l}{D} \qquad \text{(Equation C-2)}$$

where

v = linear velocity of the gas through the leak;
ρ = gas density;
f = the dimensionless friction number;
l = length of the system; and
D = diameter of the system.

IPCC assumes that that the friction number, f, is one due its independence from the nature of the gas. IPCC assumes that the internal pressure and physical dimensions of the pipeline are the same for CH_4 and CO_2. These assumptions result in the velocity being proportional to the square root of the density, and therefore proportional to the square root of the molecular weights when assuming an ideal gas, as shown in the equation below.

$$v \sim \frac{1}{\sqrt{\rho}} \quad \text{or} \quad v \sim \frac{1}{\sqrt{\text{Molecular Weight}}} \qquad \text{(Equation C-3)}$$

The mass emission rate is equal to the product of the velocity, area, and gas density:

$$\text{Mass emission rate} = v \times (\text{area}) \times \rho \qquad \text{(Equation C-4)}$$

Substituting Equation C-4 into the proportionality represented by Equation C-3 and expressing the densities as being proportional to the molecular weights (16 for CH_4 and 44 for CO_2) yields Equation 7-15, repeated here.

$$EF_{CO_2} = EF_{CH_4} \times \sqrt{\frac{44}{16}} \qquad \text{(Equation 7-15)}$$

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Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Natural Gas and Oil Industry

Appendix D – Additional Information

November 2021

Table of Contents

List of Tables

D. ADDITIONAL INFORMATION

This section provides additional information to supplement general methodologies and calculation approaches presented throughout the API *Compendium*.

D.1 “Weathered” Crude and Other Petroleum Product Vented CH_4 and CO_2 Emissions

Total hydrocarbon emissions and/or VOC emissions are commonly estimated from liquid loading, ballasting, and transit operations associated with refined petroleum liquids. As described in this section, CH_4 and CO_2 emissions are not expected from these operations. Unless site specific data indicate otherwise, CH_4 and CO_2 emissions should only be calculated for vented emissions from “live” crude.

Live crude is the term used for crude oil that has not been exposed to the atmosphere. Live crude may contain CH_4 and/or CO_2. Once “live” crude reaches atmospheric pressure and the volatile CH_4/CO_2 has flashed off (as described in Section 6.3.9.1), the crude is considered “weathered” and the crude oil vapors contain very little, if any, CH_4 or CO_2.

Analyses for “weathered” crude oil are provided in Table D-1, for crude produced in three locations: Alaska North Slope, Utah Altamont, and San Joaquin Valley (API, 2000). As shown in Table D-1, there is no C1 (i.e. CH_4) in the “weathered” crude.

Table D–1. Liquid “Weathered” Crude Speciation Data

Constituent	Alaska North Slope (ANS) Crude	Utah Altamont (ALT) Crude	San Joaquin Valley (SJV) Crude
	Weight %		
C1	0.0000	0.0000	0.0000
C2	0.0020	0.0000	0.0000
C3	0.0550	0.0000	0.0000
C4	0.6370	0.0130	0.0000
C5	1.1910	0.1560	0.0040
C6	2.2560	0.8230	0.0170
C7	2.8820	1.9940	0.0520
C8	3.1590	2.6860	0.1160

Table D–1. Liquid “Weathered” Crude Speciation Data, continued

	Alaska North Slope (ANS) Crude	Utah Altamont (ALT) Crude	San Joaquin Valley (SJV) Crude
Constituent	**Weight %**		
C9	2.5680	2.6090	0.2420
C10	2.5270	2.5170	0.4190
C11	1.5800	2.0370	0.3420
C12	0.9930	1.8420	0.2560
C13	0.3720	0.0000	0.0850

Source:
API, *Comprehensive Report of API Crude Oil Characterization Measurements*, August 2000. Analyses shown are the for the whole crude, and are sums of individual weight percents identified for parafins, iso-parafins, aromatics, and naphthalenes. Additional speciation data is provided in Table 14; methane is not listed in Table 14 other than as presented here.

Because “weathered” crude contains no CH_4, refined petroleum products also contain no CH_4. (The refining process does not add CH_4 to the liquids being refined.) Thus, for petroleum liquids other than “live” crude, the liquid phase CH_4 content is assumed to be zero. Examples of “weathered” crude oil and refined petroleum product liquid phase compositions are presented in Table D-2. Note that CH_4 is not present in the liquid composition data, as expected.

Table D–2. Average Liquid Compositions by Fuel Type

	Gasoline [a]	No. 1 Diesel Fuel [b]	Ultra Low Sulfur Diesel [c]	No. 4 Fuel Oil [d]	No. 5 Fuel Oil [e]	No. 6 Fuel Oil [f]	Crude Oil [g]
Constituent	**Weight %**						
C_2 Compounds							
Ethanol	11						
C_4 Compounds							
Butane	4						
C_5 Compounds							
Isopentane	9						
Methyl-Tert-Butyl Ether	15						
Pentane	4						
C_6 Compounds							
2,3-Dimethylbutane	2						
2-Methylpentane	4						
3-Methylpentane	2						
Benzene	2		Trace				0-2
n-Hexane	2						
C_7 Compounds							
2-Methylhexane	1						
3-Methylhexane	2						
Methylcyclohexane	1						
Toluene	5						0-20
C_8 Compounds							
Ethyl Benzene	2	0 - 1					0-4

Table D–2. Average Liquid Compositions by Fuel Type, continued

Constituent	Gasoline [a]	No. 1 Diesel Fuel [b]	Ultra Low Sulfur Diesel [c]	No. 4 Fuel Oil [d]	No. 5 Fuel Oil [e]	No. 6 Fuel Oil [f]	Crude Oil [g]
	Weight %						
C_{9+} Compounds							
Ethylmethylbenzenes (Ethyltoluenes)		1 - 3					
1, 2, 4 Trimethylbenzene		0 - 1					
5-methylchrysene						0.01-2	
Benzo(a)phenanthrene						0.01-0.1	
Cumene		0 - 1					
Naphthalene		0 - 3	Trace	0.01-0.2	0.01-0.15	0.01-0.15	
Nonane, all isomers		20 - 30					
Trimethyl Benzene	8	0 - 2					0-2
Xylene	10	0 - 1					0-20
Other Compounds							
Catalytic Cracked Clarified Oil				0-60	0-100	0-90	
Diesel Oil				10-40		0-30	
Fuel Oil No. 6				30-60	0-70		
Hydrogen Sulfide				0-0.01	0-0.01	0-0.01	0-1
Middle Distillate Fuel					10-30		
Petroleum Residua				0-24	0-28	0-100	
Polycyclic aromatic hydrocarbons (PAHs)			Up to 10				1-10
Sulfur Compounds			<0.0015	1-3	1-3	0.5-4	

Footnotes and Sources:

[a] Taken from Kinder Morgan MSDS for Unleaded Gasoline, revised 18 Feb 2003. The MSDS notes that "because of volatility considerations, gasoline vapor may have concentrations of components very different from those of liquid gasoline. The major components of gasoline vapor are: butane, isobutane, pentane, and isopentane."

[b] Taken from Citgo MSDS for No. 1 Diesel Fuel, All Grades, revised 12/31/07.

[c] Taken from Irving MSDS for Ultra Low Sulphur Diesel, revised December 23, 2006.

[d] Taken from Marathon MSDS for Marathon No. 4 Fuel Oil, revised 07/25/2006.

[e] Taken from Marathon MSDS for Marathon No. 5 Fuel Oil, revised 07/25/2006.

[f] Taken from Marathon MSDS for Marathon No. 6 Fuel Oil, revised 07/25/2006.

[g] Taken from El Paso Corporation MSDS for Crude Oil, revised 06/26/2007.

For the most part, the vapor phase of a fuel will consist of the lighter hydrocarbons present in the liquid phase of the fuel. This is due to the fact that lighter hydrocarbons, having a higher vapor pressure, will more readily volatilize than heavier hydrocarbons. Since CH_4 is an extremely light hydrocarbon, it volatilizes readily, and would therefore be expected in the vapor phase of the fuel. Conversely, if there is no CH_4 in the liquid phase of the fuel, it can be assumed that there is no CH_4 in the vapor phase of the fuel.

As demonstrated in Tables D-1 and D-2, there is no CH_4 in the liquid phase of "weathered" crude or refined petroleum products. For this reason, it can be expected that there is no CH_4 in the vapor phase of the fuels. To validate this assumption, typical "weathered" crude oil and refined petroleum product vapor compositions are presented in Table D-3 (EPA, SPECIATE Version 4.0, 2006). As expected, it is observed from the vapor composition data that there is no CH_4 in any of the vapor streams.

Table D–3. Vapor Phase Speciation Data[a]

Constituent	Crude [b,c]	Gasoline [b,d]	Distillate [b,e]	Jet Fuel (Jet A) [f,g]
	Weight %			
C_2 Compounds				
Ethane	4.17	0.07	2.13	
C_3 Compounds				
Propane	16.9	1.06	12.7	
Propylene	0.39			
C_4 Compounds				
Cis-2-butene		0.83		
Isobutane	4.42	8.34	7.34	
N-butane	24.5	28.53	28.08	
Trans-2-butene		1.02		
C_5 Compounds				
1-pentene		0.86		
Cis-2-pentene		0.67		
Cyclopentane		0.61		
N-pentane	12.77	7.25	7.97	
Trans-2-pentene		1.37		
C_6 Compounds				
2,2-dimethylbutane		1.04		
3-methylpentane		1.99		
Benzene	1.04	1.41	2.57	
Cyclohexane	0.66	0.43	1.23	
Methylcyclopentane		1.41		
N-hexane	6.3	3.75	5.61	
C_7 Compounds				
2,4-dimethylpentane		0.43		
3-methylhexane		0.42		
Methylcyclohexane		0.12		
N-heptane	6.37	0.4	1.7	0.1
Toluene	0.79	1.25	2.06	

Table D–3. Vapor Phase Speciation Data [a], continued

Constituent	Crude [b,c]	Gasoline [b,d]	Distillate [b,e]	Jet Fuel (Jet A) [f,g]
	Weight %			
C_8 Compounds				
2,2,4-trimethylpentane		0.42		
2,3,4-trimethylpentane		0.07		
3-methylheptane		0.06		
Ethylbenzene	0.07	0.06	0.32	
N-octane	4.2	0.03	0.01	0.5
C_{9+} Compounds				
1,2,4-trimethylbenzene (1,3,4-trimethylbenzene)	0.01	0.05	0.37	
1,3,5-trimethylbenzene		0.02		
Isopropylbenzene (cumene)	0.04	0.01	0.05	
N-decane				19.6
N-dodecane				18.2
N-nonane			0.04	4.7
N-tridecane				17.7
N-undecane				20.3
O-xylene	0.03	0.04	0.13	
Pentadecane				7.2
Tetradecane				11.7
Other Compounds				
Unidentified [h]	17.34	35.98	27.69	
Data Quality Rating [i]	N/A	N/A	N/A	3
EPA SPECIATE Program Profile Number	2487	2490	2488	0100

Footnotes and Sources:

[a] EPA Speciate Version 5.1, June 2020.

[b] Profiles normalized to equal 100% for the sum of the 55 PAMS (Photochemical Assessment Monitoring Stations) pollutants + MTBE, UNIDENTIFIED and OTHER.

[c] Composite of 7 Emission Profiles from Crude Oil Storage Tanks – 1993.

[d] Composite of 14 Emission Profiles from Gasoline Storage Tanks – 1993.

[e] Composite of 9 Emission Profiles from Distillate Oil Storage Tanks. – 1993.

[f] Fixed Roof Tank - Commercial Jet Fuel (Jet A).

[g] Engineering evaluation of literature data.

[h] The “Unidentified” fraction is typically the high molecular weight tail of liquids that are very hard to separate, identify and quantify by most typical gas chromatography speciation methods.

[i] Quality rating pertains to the quality of the data; "5" has the highest quality while "1" has the lowest quality.

In accordance with the liquid and vapor phase compositions shown in Tables D-1 through D-3, the CH_4 content (and therefore, vented and fugitive CH_4 emissions) of all petroleum liquids other than “live” crude oil is assumed to be zero if measured data demonstrating otherwise are not available. However, where site data indicates that CH_4 is contained in the vapor stream, CH_4 emissions should be estimated from vented activities. For example, some cracking or coking operations might produce CH_4 as a part of the process of breaking up larger molecules into smaller molecular fragments.

The vapor phase CH_4 content of "live" crude oil is assumed to be 15 percent by weight (wt%), if site-specific data are not available. This assumption is derived from AP-42, which reports that the VOC comprises 55-100 wt% of the TOC, with a typical value of 85 wt% (EPA, AP-42 Section 5.2, 2008). Assuming that the CH_4 comprises 15 wt. % of the TOC is a simplifying assumption because the non-VOC portion of the TOC includes both CH_4 and ethane; the ethane content has been discounted in the assumed 15 weight % CH_4 in the vapor phase.

Note that although CO_2 was not analyzed in the speciation data presented in Tables D-1 through D-3, CO_2 is not expected to be present in "weathered" crude or other refined petroleum products, in either the liquid or vapor phases. Carbon dioxide that is entrained in the oil from the producing formation is usually separated into the produced gas at the oil/gas separators during the production phase. Carbon dioxide is therefore not expected in any appreciable amount in the liquid after separation of the gases in the field. However, where site data shows that CO_2 is contained in the vapor stream, CO_2 emissions should be estimated from vented activities.

These assumptions are consistent with AP-42, which notes that the non-VOC (i.e., CH_4 and C_2H_6) portion of TOC emissions from other petroleum liquids is generally considered negligible (EPA, AP-42 Section 5.2, 2008).

D.2 Default GRI/EPA Methane and Carbon Dioxide Compositions

The default CH_4 and CO_2 compositions used to develop emission factors presented in Sections 6 and 7 are presented in Table D-4.

Table D–4. Default GRI/EPA Methane and Carbon Dioxide Compositions

Industry Segment	Average Methane Composition [a]	Uncertainty [a,b] (±%)	Average Carbon Dioxide Composition	Uncertainty [d] (±%)
Production	78.8%	5.53%	3.78 [c]	4%
Gas Processing [e]	87.0%	6.54%	2.0 [f]	4%
Transmission	93.4%	1.80%	2.0 [f]	4%
Distribution	93.4%	1.80%	2.0 [f]	4%

Footnotes and Sources for Table D-4:

[a] Shires, T.M., M.R. Harrison. *Methane Emissions from the Natural Gas Industry, Volume 6: Vented and Combustion Source Summary,* GRI-94/0257.23 and EPA-600/R-96-080f. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[b] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original methane compositions.

[c] Dalrymple, D.A., F.D. Skinner, and N.P. Meserole. *Investigation of U.S. Natural Gas Reserve Demographics and Gas Treatment Processes*, Topical Report, GRI-91/0019. Gas Research Institute, January 23, 1991.

[d] Uncertainty is based on engineering judgment at a 95% confidence interval.

[e] Composition based on "after the processing plant", i.e., leaving the processing sector.

[f] The CO_2 compositions for gas processing, transmission, and distribution are assumed values based on pipeline quality gas.

D.3 Atmospheric Oxidation of Emissions

A conversion factor of 0.6 wt% CH_4 in TOC has been cited by some GHG regulations (CARB, draft WCI). As demonstrated in Section D.1, the 0.6 factor is not consistent with measured CH_4 concentrations for "weathered" crude or refined petroleum products and is significantly higher than the default 15 wt% suggested by EPA for "live" crude. This section provides the origin of the 0.6 factor as cited by CARB.

Most, if not all, organic carbon compounds are subject to a myriad of atmospheric chain reactions, including photo oxidation that would eventually form atmospheric CO_2. IPCC provided a methodology to account for estimating CO_2 emissions from emissions of CH_4, CO, and Non-Methane Volatile Organic Compounds (NMVOC), as shown in Equations D-1, D-2, and D-3 (IPCC, Draft Volume 1, Chapter 7, 2006).

$$\text{Emissions}_{CO_2} = \text{Emissions}_{CH_4} \times \frac{44}{16} \qquad \text{(Equation D-1)}$$

where

Emissions CO_2 = emissions of CO_2 formed through atmospheric oxidation;
Emissions CH_4 = emissions of CH_4 from inventory;
44 = molecular weight of CO_2; and
16 = molecular weight of CH_4.

$$\text{Emissions}_{CO_2} = \text{Emissions}_{CO} \times \frac{44}{28} \qquad \text{(Equation D-2)}$$

where

Emissions CO_2 = emissions of CO_2 formed through atmospheric oxidation;
Emissions CO = emissions of CO from inventory;
44 = molecular weight of CO_2; and
28 = molecular weight of CO.

$$\text{Emissions}_{CO_2} = \text{Emissions}_{NMVOC} \times C \times \frac{44}{12} \qquad \text{(Equation D-3)}$$

where

Emissions of CO_2 = emissions of CO_2 formed through atmospheric oxidation;
Emissions_{NMVOC} = emissions of NMVOC from inventory;
C = mass fraction of carbon in NMVOC;
44 = molecular weight of CO_2; and
12 = molecular weight of C.

The factor "C" in Equation D-3 is the mass fraction of carbon in the NMVOC, which should be calculated based on the speciation of the NMVOC compounds. Alternatively, IPCC provides a *default carbon fraction of 0.6*. The 0.6 default factor provided by IPCC should only be used as the weight fraction of carbon in non-methane VOC emissions for the purpose of determining atmospheric CO_2, after all atmospheric oxidation reactions have taken place. It is in no way related to the CH_4 content of non-methane hydrocarbon emissions or of the petroleum streams, and therefore is not appropriate for directly calculating emissions of CO_2 or CH_4.

D.4 Non-GHG Emission Sources

Many emission sources at oil and gas facilities are sources of VOCs but are not sources of GHG emissions. As such, a methodology is not provided in this API *Compendium* for calculating GHG emissions from these sources.

Non-GHG sources at production facilities include the following:

- Chemical Storage Tanks;
- Glycol Storage Tanks;
- Mud Cuttings Roll-Off Bins;
- Naphtha Storage Tanks;
- Slop Oil Tanks;
- Sumps; and
- Water Blowdown Tanks.

Additional non-GHG sources which may be present at refineries include the following:

- Cooling Towers;
- Equipment Leaks from liquid process streams[1];
- Product Tanks (e.g. gasoline tanks)[1];
- Oil/Water Separators; and
- Process Drains.

Marketing terminals may also be sources of VOC emissions (such as from equipment leaks and storage tanks), but are not sources of GHG emissions.

D.5 References

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[1] Note that if site specific data indicates CH_4 or CO_2 are present in the vapors, methodology is provided for emission calculations in Appendix B.

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Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Natural Gas and Oil Industry

Appendix E – Refinery Methane Fugitive Emissions Study

November 2021

Table of Contents

List of Tables

E. REFINERY METHANE FUGITIVE EMISSIONS STUDY

E.1 Overview

This appendix describes the results of a study to test the hypothesis that CH_4 fugitive emissions are negligible compared to overall refinery GHG emissions. The study has estimated CH_4 fugitive emissions for two refineries: a small relatively simple refinery and a larger more complex refinery. Information on the refineries is provided in Table F-1.

Table E-1. Refinery Background Data

	Refinery A	**Refinery B**
Refinery Type	Fuels refinery	Integrated fuels & chemicals
Capacity (BPD)	50,000 to 99,000	100,000 to 199,000
Process Type	Single train (multiple HDS)	Old multi-train refinery

E.2 Study Summary

The study approach is to gather data on the numbers of components in natural gas and refinery fuel gas service. Potential emissions are estimated using the average emission factor for gas service for the oil and gas industry rather than applying refinery emission factors since the refinery emission factors specifically exclude streams exceeding 10% CH_4. Control effectiveness estimates are taken from the Protocol for Equipment Leak Emission Estimates, Table 5-3, published by EPA in 1995. The control effectiveness factors are applied only for components subject to formal LDAR, which normally applies to refinery fuel gas service components, but not to natural gas service components.

Data are also gathered from the refinery on their overall GHG inventory. This allows a comparison of the estimated CH_4 fugitive emissions as a percent of the overall GHG inventory in CO_2-equivalents. One of the refineries provided CO_2 emissions both with and without imported electricity. Imported electricity emissions were not included in the base GHG emissions to which the contribution of fugitive CH_4 emissions was compared.

Tables F-2 and F-4 present GHG emission inventory data (not including fugitive CH_4) for Refineries A and B, respectively. Tables F-3 and F-5 present fugitive CH_4 emissions summary data for Refineries A and B, respectively. Unit level component counts and emission calculation tables are also available, but they have not been included because the unit names and configurations might allow identification of the refineries.

Table E-2. Refinery A Greenhouse Gas Emissions Inventory

Compound	Emissions	Units	Factor	CO_2e	Units
CH_4 [a]	19.48	ton/year	21	371	tonnes/year
N_2O	16.98	ton/year	310	4,775	tonnes/year
CO_2	732,675	ton/year	1	664,672	tonnes/year
Total Greenhouse Gas Emissions:				**669,819**	**tonnes/year CO_2e**

Footnote:
[a] Not including fugitive CH_4.

Table E-3. Refinery A Fugitive CH_4 Emissions Summary

Service	# Components	CH_4 Emissions (tonnes/year)	CO_2e (tonnes/year)	% of GHG CO_2e Emission Inventory
Natural Gas	2,780	26	544	0.08%
Fuel Gas	5,432	10	216	0.03%
Make Gas	159	0.2	5	0.001%
Totals	8,371	36	765	0.11%

Table E-4. Refinery B Greenhouse Gas Emissions Inventory

Compound	Emissions	Units	Factor	CO_2e	Units
CH_4 [a]	53	ton/yr	21	1,004	tonnes/yr
N_2O	19	ton/yr	310	5,364	tonnes/yr
CO_2 [b]	1,912,392	ton/yr	1	1,734,895	tonnes/yr
CO_2 [c]	1,618,748	ton/yr	1	1,468,505	tonnes/yr
Total Greenhouse Gas Emissions:				**1,741,263**	**tonnes/yr CO_2e[b]**
				1,474,873	**tonnes/yr CO_2e[c]**

Footnotes:
[a] Not including fugitive methane.
[b] Includes imported electricity.
[c] Excludes imported electricity.

Table E-5. Refinery B Fugitive CH_4 Emissions Summary

Service	# Components	CH_4 Emissions (tonnes/year)	CO_2e (tonnes/year)	% of GHG CO_2e Emission Inventory
Natural Gas	5,744	55	1,149	0.08%
Fuel Gas	21,002	77	1,609	0.11%
Make Gas [a]	--	--	--	--
Totals [b]	26,746	131	2,759	0.19%

Footnotes:
[a] No separate data for make gas were gathered at Refinery B.
[b] Excludes imported electricity.

E.3 Conclusions

The study has completed data gathering and analyses for two refineries: a small simple refinery and a larger, more complex refinery. The estimated CH_4 fugitive emissions represent about 0.11% of the total GHG inventory for the small/simple refinery and about 0.19% of the GHG inventory for the large/complex refinery. Since other large GHG emitting sources have uncertainties in the range of 1% to 5% of the overall GHG inventory, a CH_4 fugitive emission contribution in the range of 0.1% to 0.2% does appear to be negligible.

E.4 References

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Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Natural Gas and Oil Industry

Appendix F – API Report, *Proposed Alternative Method for Calculating Emissions from Hydraulic Fracturing Operations Using Gilbert-Type Correlation*, 2015

November 2021

Proposed Alternative Method for Calculating Emissions from Hydraulic Fracturing Operations Using Gilbert-Type Correlation

20 October 2015

Prepared for:
American Petroleum Institute
1220 L Street, NW
Washington, DC 20005-4070

Prepared by:

TRIMERIC CORPORATION

PO Box 826
Buda, TX 78610
Phone: 512 295 8118
Fax: 512 295 8448
www.trimeric.com

Table of Contents

List of Tables

List of Figures

F. *Hydraulic Fracturing Venting Methodology*

F.1 Executive Summary

The United States Environmental Protection Agency (EPA) developed the Mandatory Greenhouse Gas Reporting Rule, published in the Code of Federal Regulations at 40 CFR 98, as a tool to help policy makers assess potential actions to take regarding greenhouse gases (GHGs). Subpart W "Petroleum and Natural Gas Systems" of 40 CFR 98 prescribes GHG emission estimation methodologies and reporting requirements for the oil and natural gas industry. Within the category of estimating GHG emissions from the act of flowing back gas wells following hydraulic fracturing, the existing methodologies involve the use of expensive and time-consuming measurement methods, or the application of inaccurate equations.

As an alternative to measuring the flowback volume of GHG emissions from a fractured well, EPA specifies using equations for sonic and subsonic flow (EPA Equations W-11A, W-11B and W-11C), which appear to be derived from the ideal gas law. Anecdotal evidence from member companies of multiple trade organizations indicated that these equations may overestimate flow rates by as much as 600%, although in some cases it may underestimate flow rates as well.

In a prior evaluation, Noble Energy Inc. (Noble) and Trimeric Corporation (Trimeric) investigated and evaluated empirical methods to estimate GHG emissions from flowback operations that follow hydraulic fracturing of oil wells in the Denver-Julesburg (DJ) basin. A number of earlier developed correlations for multiphase flow were considered before choosing the Gilbert-type correlation as a potentially applicable equation for that evaluation. The goal of that evaluation was to compare the accuracy of the ideal gas type equation in a multiphase flow regime with a Gilbert-type predictive multiphase flow correlation using both site-specific and field-wide coefficients. The results of the prior study indicated that the Gilbert-type correlation estimates the overall volume of gas produced during a flowback operation more accurately than Subpart W Equation W-11B for two sets of data from thirteen total wells. The Gilbert-type correlation estimates the cumulative gas volume for these two sets of thirteen wells within 0% to 3% of the measured volume, while EPA Equation W-11B overestimates the gas volume by 98% to 464%. (Sexton et al. 2014)

Trimeric has since expanded on the original study with the support of the American Petroleum Institute (API) and its member companies to evaluate the Gilbert-type correlation for ten additional oil wells in the DJ basin and a second basin containing gas wells with additional data sets provided by multiple oil and natural gas producing companies. The objective of the expanded study is to evaluate whether there is an influence of basin location and/or the oil and natural gas producer on the efficacy of the Gilbert-type correlation.

The results of this study indicate that the Gilbert-type correlation using field-wide regressed coefficients also estimates the overall volume of gas produced during a flowback operation more accurately than the single-phase flow EPA equation W-11B in 40 CFR 98 for the ten additional wells in the DJ basin and a second undisclosed basin, which has its identity protected due to confidentiality agreements with the oil and natural gas producers who provided production data from that basin. When the Gilbert-type correlation was used for the subset of wells used to develop the a/b/c coefficients, the correlation estimates the cumulative gas volume within 1% to 3% of the measured volume for four sets of wells from different oil and natural gas producers; when the Gilbert-type correlation was used for wells external from the subset to predict the cumulative gas volume, the correlation predicts the cumulative gas volume within 10% to 21%. For these same four sets of wells, EPA Equation W-11B estimates the cumulative gas volume within 18% to 497%; for three of the four sets of wells, EPA Equation W-11B overestimates the cumulative gas volume by 75% of more.

The overall results and conclusions were consistent with prior results obtained from the DJ basin. Furthermore, despite the operational data collected by the three different producers in the second basin containing highly variable gas to liquid ratios, tubing pressures, choke sizes, and durations of flowback after hydraulic fracturing, the Gilbert-type correlation more accurately estimated the volume of gas produced than EPA estimation methods.

This multiphase flow correlation should be given further consideration as an alternative method for estimating gas emissions from flowback operations. Based upon analysis performed in this report, data from a representative set of seven to ten wells is a satisfactory sample size to develop Gilbert-type coefficients that can be used a predictive tool for the rest of the field for an individual oil and natural gas producer. Furthermore, data from other API member companies suggests that existing historical data could potentially be used to develop these coefficients; it may not be necessary for an individual oil and natural gas producer to collect new data to utilize this method.

Disclaimer: The calculations in this report are based on measured gas flow rate and liquid production data provided by the API member companies. The primary purpose of the material is to advance the proposition that Gilbert-type correlation can be effectively utilized for these data sets; some of the data included in these calculations may come from operations that do not fall within the definition of flow back operations as defined by 40 CFR 60 Subpart OOOO and 40 CFR 98 Subpart W. Further, cumulative gas volumes as reported in this evaluation do not specifically represent atmospheric emissions; cumulative gas volumes may be routed to a pipeline, flared, or vented to the atmosphere.

F.2 Introduction

The EPA developed the Mandatory Greenhouse Gas Reporting Rule, published in the Code of Federal Regulations in 40 CFR 98, as a tool to help policy makers assess potential actions to take regarding greenhouse gases. Subpart W "Petroleum and Natural Gas Systems" of 40 CFR 98 prescribes GHG emission estimation methodologies and reporting requirements for the oil and natural gas industry. EPA and industry representatives have been working together to identify inaccurate estimation techniques and to work toward acceptable corrected methods. Within the category of estimating GHG emissions from the act of flowing back gas wells following hydraulic fracturing, the existing methodologies involve the use of expensive and time-consuming measurement methods, or the application of inaccurate equations. The development of improved emission estimation procedures for this emission source is the subject of this paper.

Subpart W allows three methods for estimating GHG emissions from flowbacks from hydraulically fractured gas wells.

- One method involves instrumentation that measures and records the flowback volume of gas that contributes to GHG emissions for each fractured well.
- The second method involves cases where many wells are being fractured. In this scenario, the flowback volume of gas from a smaller population of wells is measured, and results from this subset of wells are scaled for other wells using a scalar based on the first 30 days of initial production. This method, along with the previous method, incurs significant expenses, with most operations lasting days to weeks.
- A more economically feasible method for estimation of flowback volume is presented by the EPA in Equations W-11A (used for sub-sonic flow conditions) and W-11B (used for sonic flow conditions), which are represented in Eq. F-1 and Eq. F-2:

$$FR_a = 1.27x10^5 * A * \sqrt{3430 * T_u * \left[\left(\frac{P_2}{P_1}\right)^{1.515} - \left(\frac{P_2}{P_1}\right)^{1.758}\right]} \text{ ....(F-1)}$$

$$FR_a = 1.27x10^5 * A * \sqrt{187.08 * T_u} \text{ ....(F-2)}$$

A = orifice cross-sectional area, m^2
FR_a = actual average gas flow rate, ft^3/hr
P_1 = upstream pressure, psia
P_2 = downstream pressure, psia
T_u = upstream temperature, degrees Kelvin

Anecdotal evidence from member companies of multiple trade organizations indicates that Equations W-11A and W-11B, which can be derived from the ideal gas law, frequently overestimates flow rates. The flowback fluid is a combination of the fluid injected during the fracture stimulation process (this may include liquids like water and gaseous fluids such as carbon dioxide or nitrogen), in-situ formation water, petroleum fluids such as oil and condensate, and natural gases. Since the composition is constantly changing and it is composed of multiple fluid phases, the use of single phase equations like Equations W-11A and W-11B can be problematic.

In a prior study (Sexton et al. 2014), Noble and Trimeric investigated and evaluated empirical methods to estimate GHG emissions from flowback operations that follow hydraulic fracturing of oil wells. A number of earlier developed correlations for multiphase flow were considered before choosing the Gilbert-type correlation as a potentially applicable equation for this case. The goal of that analysis was to compare the accuracy of the ideal gas type equation in a multiphase flow regime with a Gilbert-type predictive multiphase flow correlation using both site-specific and field-wide regressed coefficients from data collected in the Denver-Julesburg (DJ) basin. The results of the study indicated that the Gilbert-type correlation estimates the overall volume of gas produced during a flowback operation more accurately than Subpart W Equation W-11B. The Gilbert-type correlation estimates the cumulative gas volume for these ten wells within 3% of the measured volume, while EPA Equation W-11B overestimates the gas volume by 98%. (Sexton et al. 2014)

The objective of this paper is to expand on the original study to determine if data collected during a flowback operation can be used to estimate and/or predict the total gas volume produced during the flowback across a number of basins for a large group of data, independent of the production company. Trimeric compared the Gilbert-type correlation method to both Equation W-11B from 40 CFR 98 Subpart W and the total gas volume measured during the course of the entire flowback operation for ten additional oil wells in the DJ basin and for thirty data sets from three oil and natural gas producers in a different basin containing gas wells. Subsequent sections of this report will address the following evaluations:

- An explanation of the theory and applicability of the Gilbert-type correlation
- A description of an example flowback operation

- An evaluation of data and development of Gilbert-type coefficients from three companies in an unnamed basin
- A predictive analysis of GHG emissions using the Gilbert-type coefficients from three companies in an unnamed basin, and a comparison to EPA Equation W-11B
- A predictive analysis of GHG emissions using the Gilbert-type coefficients from Noble Energy in the DJ basin, and a comparison to EPA Equation W-11B
- Summary and conclusions associated with use of the Gilbert-type correlation to predict greenhouse gas emissions

F.3 Literature Review/Theory

40 CFR 98.233(g) within Subpart W defines the activity of gas well venting during completions and workovers and explains the methodology for estimating GHG emissions from this activity. Per 40 CFR 98, well completions are defined as *the process that allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and test the reservoir flow characteristics, steps which may vent produced gas to the atmosphere via an open pit or tank. Well completion also involves connecting the well bore to the reservoir, which may include treating the formation or installing tubing, packer(s), or lifting equipment, steps that do not significantly vent natural gas to the atmosphere. This process may also include high-rate flowback of injected gas, water, oil, and proppant used to fracture and prop open new fractures in existing lower permeability gas reservoirs, steps that may vent large quantities of produced gas to the atmosphere*.

Per 40 CFR 98, well workovers are defined as *processes of performing one or more of a variety of remedial operations on producing petroleum and natural gas wells to try to increase production. This process also includes high-rate flowback of injected gas, water, oil, and proppant used to re-fracture and prop-open new fractures in existing low permeability gas reservoirs, steps that may vent large quantities of produced gas to the atmosphere*.

Eqs. 1 through 3 can be used to estimate flowback emissions from each hydraulically fractured well completion/workover. 40 CFR 98.233(g) states that the well flowing pressure upstream of a well choke (and also downstream pressure in subsonic flow cases) should be recorded according to methods set forth in 40 CFR 98.234(b); the latter subsection states that an appropriate standard method published by a consensus-based standards organization or standard industry practice is an acceptable method of measuring pressure. Eq. F-3 (EPA Equation W-11C) is used first to determine if flow through the wellhead choke is sonic or subsonic flow:

$$R' = {}^{P_1}/_{P_2} \quad \text{..........(F-3)}$$

P_1 = upstream pressure, psia
P_2 = downstream pressure, psia
R' = Pressure Ratio, dimensionless

According to 40 CFR 98.233(g), if the value of R is greater than or equal to two, flow should be assumed sonic; if the value of R is less than two, the flow should be assumed subsonic. As another point of reference, Gilbert (1954) states that a pressure ratio above 1.7 should be assumed as sonic flow. These values stated above are generally accepted rules of thumb; the exact value of the pressure ratio for sonic flow is dependent upon the thermodynamic properties for a particular gas mixture, and therefore can be different for gas mixtures of different compositions.

For the purposes of this study, we will assume that Eq. F-2 for sonic flow applies. The data from flowback operations analyzed within this study were not collected with the specific objective of determining whether the wellhead choke is sonic or subsonic flow. Average pressures upstream of the wellhead choke for the thirty data sets ranged from approximately 600 psia to 3,100 psia, while average pressures downstream of the three-phase separator ranged from approximately 200 psia to 1,200 psia. If there were sufficient data for upstream and downstream pressures, we calculated the ratio of upstream to downstream pressure; for twelve of the thirteen wells with sufficient data, the pressure ratio was 2 or greater. The ratio for the other well was approximately 1.5.

Based upon this information, we believe it is reasonable to assume that the upstream/downstream pressure ratio is significantly greater than 1.7 for this evaluation and that multiphase flow through the wellhead choke is therefore sonic flow. Nevertheless, we acknowledge that the dynamic nature of these flowback operations could allow flow to transition from the sonic to subsonic flow regime.

Actual gas emissions flow rates (or volumes) can be converted from actual to standard flow rates (or volumes) using Eq. F-4 (taken from EPA Equation W-34):

$$E_{s,i} = \frac{E_{a,i} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s} \quad \text{..........(F-4)}$$

$E_{a,i}$ = volumetric gas emissions at actual temperature and pressure, ft^3/hr
$E_{s,i}$ = volumetric gas emissions at standard temperature and pressure, ft^3/hr
P_a = pressure at actual emission conditions, psia
P_s = standard pressure, psia (use value of 14.7 psia)
T_a = temperature at actual emission conditions, °F
T_s = standard temperature, °F (use value of 60°F)

Eqs. 1 and 2 can be derived by assuming that fluid through the wellhead choke is single-phase gas flow, which is presumed to be methane since the values of constants 3430 and 187.08 m^2/s^2-K in Eqs.1 and 2 (as provided by the EPA) are based on thermodynamic properties of methane. In reality, the gas-phase portion of the fluid is a mixture of methane, ethane and other higher-molecular weight (MW) volatile organic compounds; in addition, this gas can contain inert compounds such as carbon dioxide and/or nitrogen. Treating the gas-phase portion of the fluid as methane is a simplification that leads to an overestimation of the volumetric flow rate. However, this is only a secondary effect compared to the assumption that the flow is single phase gas flow as opposed to multiphase flow.

The flowback of fluids following a well fracture is not a single gaseous phase. Flow through the wellhead choke during flowback operations is multiphase. For some wells, the produced fluid is a combination of produced gas and water; for others, the produced fluid includes produced gas, water, and oil from the formation. The assumption of single-phase gas flow leads to a significant overestimation of greenhouse gas production during flowback operations because not all the fluid going through the orifice is gas.

As discussed above, the actual volume of flowback gas can be directly measured as an alternative to estimating the volume using Eqs. 1 and 2. However, the cost and effort associated with directly measuring this data is substantial.

Since the direct measurement of actual flowback data is costly, and the gas flow rates estimated using the Subpart W well choke equations can have a very high bias, alternative methods of estimating GHG flow rates from flowback operations are needed. A prior literature review (Sexton et al. 2014) revealed that the most directly applicable empirical correlation for the prediction of multiphase flow through wellhead chokes was developed by Gilbert (1954) for sonic multiphase flow through a wellhead choke, which takes the form in Eq. F-5 (refer to the Nomenclature section at the end of this report for a definition of terms):

$$P' = \frac{c * B * r^a}{S^b} \qquad \text{(F-5)}$$

a = empirically derived coefficient
b = empirically derived coefficient
B = gross liquid rate, barrels per day
c = empirically derived coefficient
P' = upstream pressure, psig
r = gas to liquid ratio, Mcf/bbl
S = bean (choke) size in 1/64th inch increments

Gilbert (1954) used data from California oil fields that produced multi-phase flow to regress values of *a* (0.546), *b* (1.89) and *c* (435) applicable to all wells in the field. Subsequent researchers modified the Gilbert-type correlation and regressed different sets of *a*/*b*/*c* coefficients for other oil and natural gas fields where multi-phase flow is present. The general form of the Gilbert-type equation for sonic flow through a wellhead choke used in this evaluation is summarized in Eq. F-6 (refer to the Nomenclature section at the end of this report for a definition of terms):

$$P = \frac{c * Q_L * R^a}{S^b} \text{..........(F-6)}$$

There is also a subsonic form of Eq. F-6 that is not covered in this study; for the data analysis involved in this study, we are assuming that all wells analyzed are at sonic/critical flow conditions. In order to regress values of the *a*/*b*/*c* coefficients, the Gilbert-type correlation must be rearranged into a linear form. The steps in Eqs. F-7 through F-10 detail the mathematical rearrangement and application of the Gilbert-type correlation into a linear equation that can be used for a multivariable linear regression.

$$\frac{P}{Q_L} = \frac{c * R^a}{S^b} \text{..........(F-7)}$$

$$ln\left(\frac{P}{Q_L}\right) = ln\left(\frac{c * R^a}{S^b}\right) \text{..........(F-8)}$$

$$ln\ (P) - \ ln\ (Q_L) = \ ln\ c + ln\ (R^a) - \ ln\ (S^b) \text{..........(F-9)}$$

$$ln\ (P) - \ ln\ (Q_L) = \ ln\ c + a * ln\ (R) - \ b * ln\ (S) \text{..........(F-10)}$$

Eq. F-10 takes the general form of a linear equation required for a regression analysis (Eq. F-11):

$$y_i = B_0 + B_1 * x_{i1} + B_2 * x_{i2} \text{..........(F-11)}$$

Once B_0, B_1 and B_2 have been calculated for a given data set, the *a*/*b*/*c* coefficients for a given production well can be determined. Assuming that $R = Q_G/Q_L$, the Gilbert-type correlation can be rearranged to the form in Eq. F-12 to predict the produced gas rate during flowback:

$$\mathrm{Q_G} = \mathrm{Q_L} * \left(\frac{\mathrm{P} * \mathrm{S^b}}{\mathrm{c} * \mathrm{Q_L}}\right)^{1/\mathrm{a}} \text{..........(F-12)}$$

a = empirically derived coefficient
b = empirically derived coefficient
c = empirically derived coefficient

P = upstream pressure, psia
Q_G = gross gas rate, Mcf per day
Q_L = gross liquid rate, barrels per day
S = bean (choke) size in 1/64th inch increments

F.4 Questionnaire to Assess Available Data

Trimeric prepared a questionnaire and submitted it to API member companies, on behalf of API, to assess the amount of information available regarding measured flowback operations on hydraulically fractured wells. Information requested within the questionnaire included general information, specific types of data collected, and a supplementary section. The questionnaire recipients were informed of API's intentions to evaluate an empirically derived correlation for multiphase flowback to estimate GHG emissions, and they were also asked to indicate their level of interest to provide field measurement data to assist with efforts to evaluate an alternative to the standard EPA equations.

Six API member companies replied to the questionnaire, each of which indicated interest in providing field measurement data to assist with the evaluation of an alternative to the standard EPA equations; responses from each of these member companies indicated that several hundred sets of sufficient flowback data were available from each member company spread across multiple basins. The responses were reviewed and summarized by Trimeric, and discussed with API and API subcommittee members in order to select an appropriate number of data sets for detailed evaluation with the Gilbert-type correlation. The responses indicated that sufficient data was available for detailed evaluation for up to three basins with input from three different producers for each of the basins. Trimeric and API selected one of the basins for detailed evaluation and requested flowback data for 10 gas wells from each of the three companies that collected data in that basin. Due to budgetary limitations, all three basins were not analyzed in detail within this evaluation; one of the three basins was selected because it primarily contains gas wells that have different characteristics than the DJ Basin.

F.5 Methodology for Application of the Gilbert-Type Correlation

For this evaluation, Trimeric used the raw hourly data collected by the oil and natural gas companies and performed the regression analysis on each hourly data point. Using the raw hourly data reduces the complexity of the overall analysis, and demonstrates the efficacy of the Gilbert-type correlation similar to the previous effort (Sexton et al. 2014) which developed daily averages of flowback data before performing regressions. Regressing the hourly data directly also eliminates any bias for use (or omission) of data from a partial day.

The following steps below provide a high-level methodology to analyze the raw hourly data sets from a series of wells to regress the *a/b/c* coefficients, and subsequently apply the coefficients for use in the Gilbert-type correlation to estimate the cumulative gas volume during flowback.

1. The first hour of flowback (as defined when both gas and liquid phases are present) was noted in the raw hourly data set. This denotes the beginning the flowback for purposes of the Gilbert-type regression analysis to derive the *a/b/c* coefficients – and for the entire analysis. The subsequent data were reviewed and any rows where data were missing were highlighted.
2. Developing the *a/b/c* coefficients for the Gilbert-type correlation requires that both gas and liquid flow exist; during periods of time where only one fluid phase or no flow exists, the Gilbert-type correlation is not applicable. The linearized form of the Gilbert-type correlation (Equation 10) includes a term for the natural log of the gas to liquid ratio, R. If no gas flow exists, then the gas to liquid ratio is zero; if no liquid flow (or no total flow exists), then the gas to liquid ratio is undefined. The natural log of zero or an undefined number is also undefined; if the value for the natural log of R does not have a defined value, then that particular hourly data set is not valid to include in the composite data set for the regression analysis of the *a/b/c* coefficients. Therefore, data points where only one fluid phase or no flow exists were excluded from the regression analysis to derive the *a/b/c* coefficients.
3. The hourly gas, water, and oil production rates were plotted as a function of flowback time and this graph is called an "Hourly Production Chart". These figures serve as a cross-check to note the times during flowback where only one phase (or no phases) of flowback are present – which per explanation above notes when the data must be excluded from the regression analysis to derive the *a/b/c* coefficients.
4. For each valid hourly data set, values for "R (Mscf gas/bbl liquid)", "Q_L (bbl liquid/day)", "$\ln(P) - \ln(Q_L)$", "$\ln(R)$" and "$\ln(S)$" were calculated as described in Equations F-5 and F-6. Note that the pressure is absolute pressure and not gauge pressure.
5. Steps #1 through #4 were repeated for every well involved in the regression analysis.
6. In a separate spreadsheet, one composite data set was constructed using all values of "$\ln(P) - \ln(Q_L)$", "$\ln(R)$" and "$\ln(S)$" from each of the wells.
7. The "Regression" tool from the "Data Analysis" ToolPak in Microsoft Excel® was used to perform a multivariable linear regression for these raw data sets to obtain values of *a*/*b*/*c* for each individual company's set of data for this basin. The Regression tool performs linear regression analysis by using the "least squares" method to fit a line through a set of data, and it can be used to analyze how a single dependent variable is affected by the values of one or more independent variables. The selected independent variable sets input into the x-range include the data sets for "$\ln(R)$" and "$\ln(S)$", while the

selected dependent variable sets input into the y-range includes the data set for "ln(P) – ln(Q_L)". The output from the Regression tool provides values for ln(c), a, and ($-b$). These $a/b/c$ values are the coefficients for the Gilbert-type correlation.

8. The flowback average tubing pressure and choke size for a given flowback operation were calculated by taking the average of all of the hourly values recorded during the course of the flowback operation. The average flow rates of produced gas, water, and oil were calculated over the entire flowback by dividing the total accumulated volume of gas, water, and oil recorded during the entire flowback operation by the total number of days for the flowback operation (this includes periods of atypical operation, which are when only one phase of flow exists or when no flow exists as previously discussed). Fractional days were included in the denominator. Expressing the average flow rates of gas, oil, and water over the entire course of the flowback on a daily basis was done so that this evaluation would be consistent with all other Gilbert-type correlation publications that Trimeric reviewed prior to selecting the Gilbert-type approach for this API study.
9. Using the $a/b/c$ coefficients and Eq. F-12, the estimated gas rate was calculated and compared to the corresponding measured gas rate. The efficacy of the Gilbert-type correlation was evaluated by applying Eq. F-12 with the company-specific field-wide $a/b/c$ coefficients and the flowback average tubing pressure, flowback average choke size, and flowback average liquid flow rate expressed on a daily rate basis.

F.6 Analysis of API Member Company-Specific Operational Data

Figure F-1 provides a process flow diagram for an example flowback operation. Once a well has been fractured, produced fluid from the well passes through a choke, which serves as a restriction in the line. After passing through the choke, the fluid flows through a tee and is initially directed to a frac tank (a generic term for a mobile liquid storage tank) that is open to atmosphere. Fluid is collected in the frac tank until gas breakthrough is observed; at this time the valve to the frac tank is closed and fluid is directed to a vertical sand separator vessel, which removes sand and solids injected during the fracturing of the well.

Initially, Valve 1 is open, Valve 2 is closed, and the wellbore is producing only the liquids remaining in the wellbore and near the wellbore region directly to the frac tank. These liquids contain no entrained hydrocarbon gas. The separators cannot operate until there is sufficient gas to pressurize the vessels. When this occurs, Valve 2 is opened and Valve 1 is closed.

Once Valve 2 is opened, the overhead fluid from the sand separator flows into a horizontal three-phase separator. Produced gas exits the top of the three-phase separator, is measured by a flowmeter, and is vented, flared, or routed to sales. This is where the flow was measured for this study. The produced oil and water liquid phases are separated and directed to separate tanks for collection. During this flowback period, the volume of liquid in each tank was recorded on an hourly basis by measuring the liquid level and converting to volume based on the level in the tank.

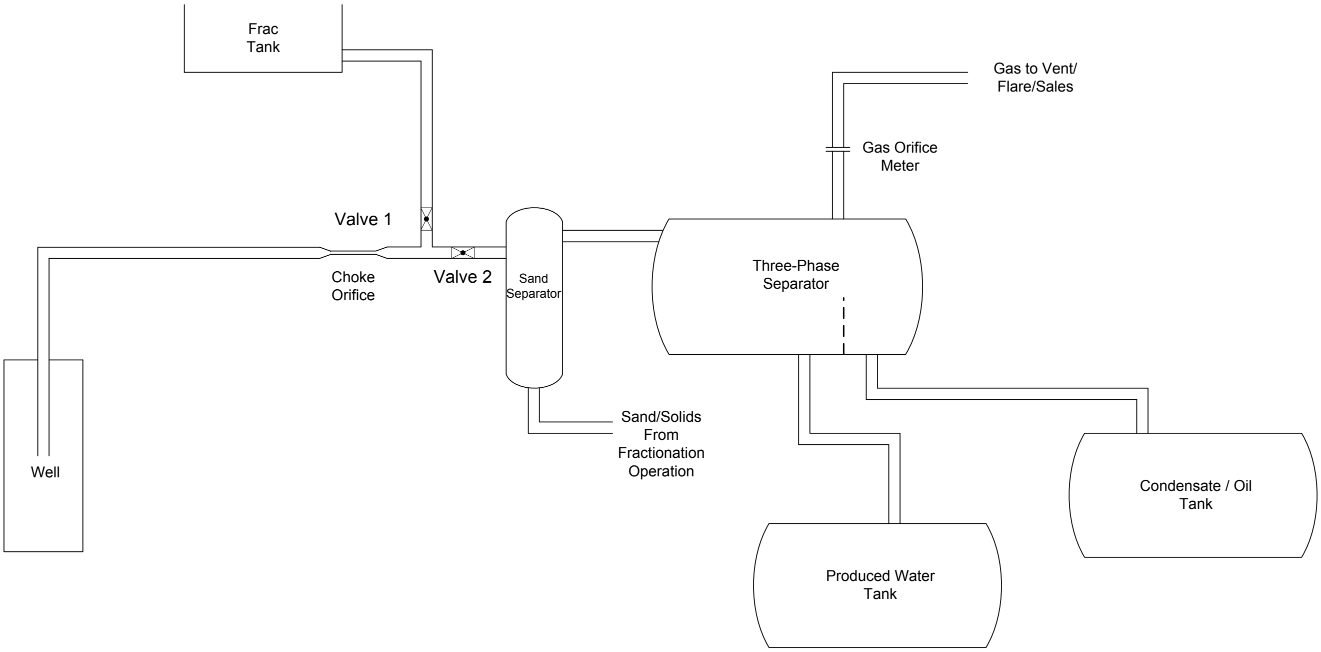

Figure F-1. Process flow diagram for an example flowback operation

Data were collected for 10 wells from each of the three API member companies within the basin chosen for the analysis (please note that the identity of the companies and the basin are kept confidential for this analysis). Seven wells from each company (21 wells total) were randomly chosen out of the 10 wells for the first part of the analysis in which each set of seven wells were used to determine a company specific set of field-wide *a/b/c* coefficients for the Gilbert-type correlation. The remaining three wells from each set were later used to evaluate the efficacy of using the Gilbert-type correlation as a predictive tool, as described later in this report.

The data necessary for the regression analysis, including upstream tubing pressure, choke size, cumulative produced gas volume, cumulative produced water volume, and cumulative produced oil volume, were recorded hourly by each member company. The raw hourly data was used for the regression analysis to obtain the *a/b/c* coefficients required for the Gilbert-type correlation.

In order to estimate the gas volume using the standard EPA equations, the average overall choke size and average upstream temperature were used with Eq. F-2 to estimate emissions. Companies A and C provided the actual upstream well temperature; in the absence of this data for Company B, we assumed that the upstream well temperature was equivalent to the temperature in the downstream three-phase separator. Eq. F-4 was then used to convert calculated actual gas volume to a standard gas volume at standard temperature and pressure conditions (60 ºF, 14.7 psia).

Seven well data sets were evaluated for each company to determine the Gilbert-type coefficients. Table F-1 summarizes the key parameters for each well that are required to apply the Gilbert-type correlation and EPA Equation W-11B; this table includes information for all thirty wells evaluated within the unnamed basin – the subset of wells used to develop the coefficients for each company, and the remaining wells used in the predictive analysis.

Table F-1. Key Parameters for Gilbert-Type Correlation and EPA Equation W-11B, Unnamed Basin

Company A

Well	Flowback Average Liquid Rate	Gas to Liquid Ratio	Flowback Average Pressure	Flowback Average Choke Size	Flowback Length	Flowback Average Upstream Well Temperature
	bbl/day	Mscf/bbl	psia	1/64" increments	days	°F
Well 1	882	3.49	2,900	20.1	2.88	102.2
Well 2	906	2.20	3,046	15.4	1.21	95.3
Well 3	1,185	1.41	1,722	12.0	0.46	90.7
Well 4	746	4.37	1,730	18.0	2.17	80.2
Well 5	756	1.30	2,404	12.0	0.50	84.7
Well 6	203	51.24	1,784	30.3	6.58	56.9
Well 7	98	117.1	3,074	28.3	6.33	74.7
Well 8	114	100.8	2,800	31.7	6.88	72.2
Well 9	384	18.13	938	59.3	5.71	69.3
Well 10	155	75.51	2,331	25.2	6.71	65.5

Company B

Well	Flowback Average Liquid Rate	Gas to Liquid Ratio	Flowback Average Pressure	Flowback Average Choke Size	Flowback Length	Flowback Average Separator Temperature
	bbl/day	Mscf/bbl	psia	1/64" increments	days	°F
Well 1	1,559	0.12	655	30.0	0.92	86.7
Well 2	1,625	0.87	1,372	27.3	0.42	96.2
Well 3	1,601	0.74	1,274	24.0	0.46	90.7
Well 4	1,775	0.37	1,127	24.6	1.50	94.8
Well 5	1,839	0.35	1,201	22.5	0.75	92.9
Well 6	1,675	0.27	593	30.9	1.38	91.1
Well 7	1,824	0.67	1,240	26.0	0.08	97.5
Well 8	1,783	0.55	1,299	20.7	0.46	87.7
Well 9	1,693	0.57	1,301	26.3	0.38	95.2
Well 10	1,736	1.23	1,319	28.3	0.25	81.8

Company C

Well	Flowback Average Liquid Rate	Gas to Liquid Ratio	Flowback Average Pressure	Flowback Average Choke Size	Flowback Length	Flowback Average Upstream Well Temperature
	bbl/day	Mscf/bbl	psia	1/64" increments	days	°F
Well 1	275	15.58	948	61.2	22.75	70.2
Well 2	525	13.89	1,309	43.9	21.54	74.2
Well 3	327	11.62	694	62.9	27.17	68.4
Well 4	556	9.03	975	62.1	17.75	75.0
Well 5	490	7.24	673	63.0	24.37	68.0
Well 6	397	19.42	1,194	53.4	21.63	73.4
Well 7	533	12.79	1,162	55.4	20.79	76.5
Well 8	272	17.90	904	62.7	18.67	70.1
Well 9	257	17.88	882	62.1	22.62	69.2
Well 10	562	9.42	1,005	62.8	17.83	72.9

The five shortest duration flowbacks (less than 2.88 days) in the Company A data set had a gas to liquid ratio in the range of 1.30 to 4.37 Mscf/bbl. For the two longer duration flowbacks, the gas to liquid ratio was between 51 and 117 Mscf/bbl. In addition, for the two longer duration flowbacks (each lasting between six and seven days), the cumulative measured gas flow rate (in Mscf/d) was significantly higher than for the five shorter duration flowbacks. As a result, the two longer duration flowbacks have a large influence on the data analysis (in terms of total volume of gas produced). The upstream pressure for the flowback data from Company A is between 1,730 and 3,074 psia; this pressure range is much greater than the pressure range for the other two companies. The Gilbert-type correlation estimated the cumulative gas volume for these seven wells within 2% of the measured volume.

However, the individual well variability of the estimates for the Gilbert-type correlation are higher for this data set compared to the others because of the large influence of the two longer duration flowbacks - which have vastly different gas to liquid ratios.

For the five shorter duration flowbacks in the Company A data set, EPA Equation W-11B overestimates the gas volume by 69%; for the two longer duration flowbacks with the much higher gas to liquid ratios, EPA Equation W-11B overestimates the gas volume by 11%. Overall, the EPA equation overestimates gas volume by 18% for the Company A data set.

For Company B, all flowbacks were short-duration (all less than 1.5 days total flowback time). The gas to liquid ratio was extremely low for all seven wells (between 0.12 and 0.87 Mscf/bbl). The upstream tubing pressure for these seven wells ranged from 593 to 1,372 psia. The Gilbert-type correlation estimates the cumulative gas volume for these seven wells within 3% of the measured volume, while EPA Equation W-11B overestimates the gas volume by 497%. This overestimation from the standard EPA equation is believed to be primarily due to the low gas to liquid ratio measured at these wells; the standard EPA equations are assuming that the flow through the choke is 100% gas-phase flow, when in reality there are significant liquids rates.

The Company C data contains data for longer-duration flowbacks (approximately 18 to 27 days). The wellhead chokes were much larger for the Company C wells relative to the other two sets of company data – ranging in average size from size 44 to 63 (in 1/64" increments). The gas to liquid ratio ranged from 7.4 to 19.4 Mscf/bbl for the seven wells included in the Company C linear regression, and the pressure ranged from 673 to 1,309 psia. The Gilbert-type correlation estimates the cumulative gas volume for these seven wells within 1% of the measured volume, while EPA Equation W-11B overestimates the gas volume by 242%.

Table F-2 presents a summary that compares the total measured volume of gas produced (in MMscf) during each flowback operation with the total estimated volume of gas produced using one flowback average upstream pressure, one flowback average choke size, one flowback average liquid production rate expressed on a daily rate basis (determined by dividing the cumulative liquid production for the entire flowback by the duration of the flowback), and the field-wide *a*/*b*/*c* constants (for each producer's data); this table also compares the measured gas volume to the gas volume estimated using the standard EPA equations for calculating the average actual gas flow rate and converting the actual flow rate to a standard gas flow rate. The seven wells listed for each company within Table F-2 are the subset of wells that were used to develop the *a/b/c* coefficients for each oil and natural gas producer; this table demonstrates the Gilbert-type correlation estimates gas volumes within 1% to 3% of the measured volumes for the wells used to develop the coefficients using the flowback average approach.

Table F-2. Estimation of gas emissions using company-specific field-wide coefficients

Company A

Site	Measured Gas Volume	Estimated Gas Volume - Gilbert Correlation	Estimated Gas Volume - EPA Equation W-11B	Gilbert Correlation Percent Error	EPA Equation W-11B Percent Error
	MMscf	MMscf	MMscf		
Well 1	8.8	11.5	19.4	30%	120%
Well 2	2.4	3.1	5.1	27%	110%
Well 3	0.8	0.3	0.7	-58%	-14%
Well 4	7.1	3.7	7.1	-47%	0%
Well 5	0.5	0.6	1.0	24%	105%
Well 6	68.6	46.8	64.6	-32%	-6%
Well 7	72.8	97.6	91.4	34%	26%
Field Total:	***161***	***164***	***189***	***2%***	***18%***

Company B

Site	Measured Gas Volume	Estimated Gas Volume - Gilbert Correlation	Estimated Gas Volume - EPA Equation W-11B	Gilbert Correlation Percent Error	EPA Equation W-11B Percent Error
	MMscf	MMscf	MMscf		
Well 1	0.17	0.32	3.14	93%	1801%
Well 2	0.59	0.83	2.46	40%	315%
Well 3	0.54	0.48	1.95	-13%	258%
Well 4	1.00	0.97	5.88	-3%	490%
Well 5	0.49	0.40	2.64	-18%	443%
Well 6	0.63	0.35	4.52	-45%	620%
Well 7	0.10	0.08	0.40	-19%	295%
Field Total:	***3.52***	***3.42***	***21.00***	***-3%***	***497%***

Company C

Site	Measured Gas Volume	Estimated Gas Volume - Gilbert Correlation	Estimated Gas Volume - EPA Equation W-11B	Gilbert Correlation Percent Error	EPA Equation W-11B Percent Error
	MMscf	MMscf	MMscf		
Well 1	97	146	476	50%	389%
Well 2	157	139	319	-12%	103%
Well 3	103	109	440	6%	327%
Well 4	89	93	392	4%	339%
Well 5	87	82	385	-5%	345%
Well 6	167	153	433	-8%	160%
Well 7	142	131	435	-8%	207%
Field Total:	***842***	***852***	***2,880***	***1%***	***242%***

This analysis shows that the Gilbert-type correlation using company-specific, field-wide coefficients provides an excellent estimate of the cumulative gas volume over a wide range of flowback durations, gas to liquid ratios, choke sizes, and upstream pressures (within 3% for all three sets of company data). EPA Equation W-11B provides an accurate estimate of gas volume for the Company A wells, which have extremely high G/L ratios and high upstream pressures. These flowbacks are approaching single-phase gas flow, which is a major assumption behind the basis for EPA Equation W-11B. However, when multiphase flow exists, the EPA equation typically overestimates the gas volume – with error as high as 497%.

These results show that the Gilbert-type correlation can be used to model these flowback operations and estimate the overall volume of produced gas with a high degree of accuracy when compared to the use of EPA Equation W-11B in the Mandatory Reporting Rule.

Figures F-2 through F-4 illustrate parity plots for the comparison of the estimated gas volume to the measured gas volume using both the Gilbert-type correlation and EPA Equation W-11B.

The objective of the parity plot is to illustrate the measured value of the gas volume during flowback (shown on the x-axis) relative to the estimated value of the gas volume (shown on the y-axis). The bold red line drawn diagonally across the plot is often referred to as the “x=y” line; this line is added as a reference to show how closely the estimated value compares to the measured value.

- If the estimated value is equal to the measured value, the point on the graph will lie on the “x=y” line
- If the estimated value is greater than the measured value, the point on the graph will lie above the “x=y” line
- If the estimated value is less than the measured value, the point on the graph will lie underneath the “x=y” line

For example, if we refer to Table F-2, the data for Company A Well 1 suggests that the measured gas volume is 8.8 MMscf, while the estimated volume using the Gilbert-type correlation is 11.5 MMscf; this data point is circled in Figure F-2 below. It shows that the data point falls above the “x=y” line. The parity plot is an effective approach to illustrating the data for an entire set of wells on one graph.

The parity plots illustrate that the Gilbert-type correlation estimates the gas volume with a high level of accuracy (as evidenced by the data points being located close to the “x=y” line). These plots also illustrates that when typical multiphase flow exists (as represented by Company B and

Company C), EPA Equation W-11B consistently overestimates the gas volume versus the measured value (as evidenced by the data points being located above the "x=y" line).

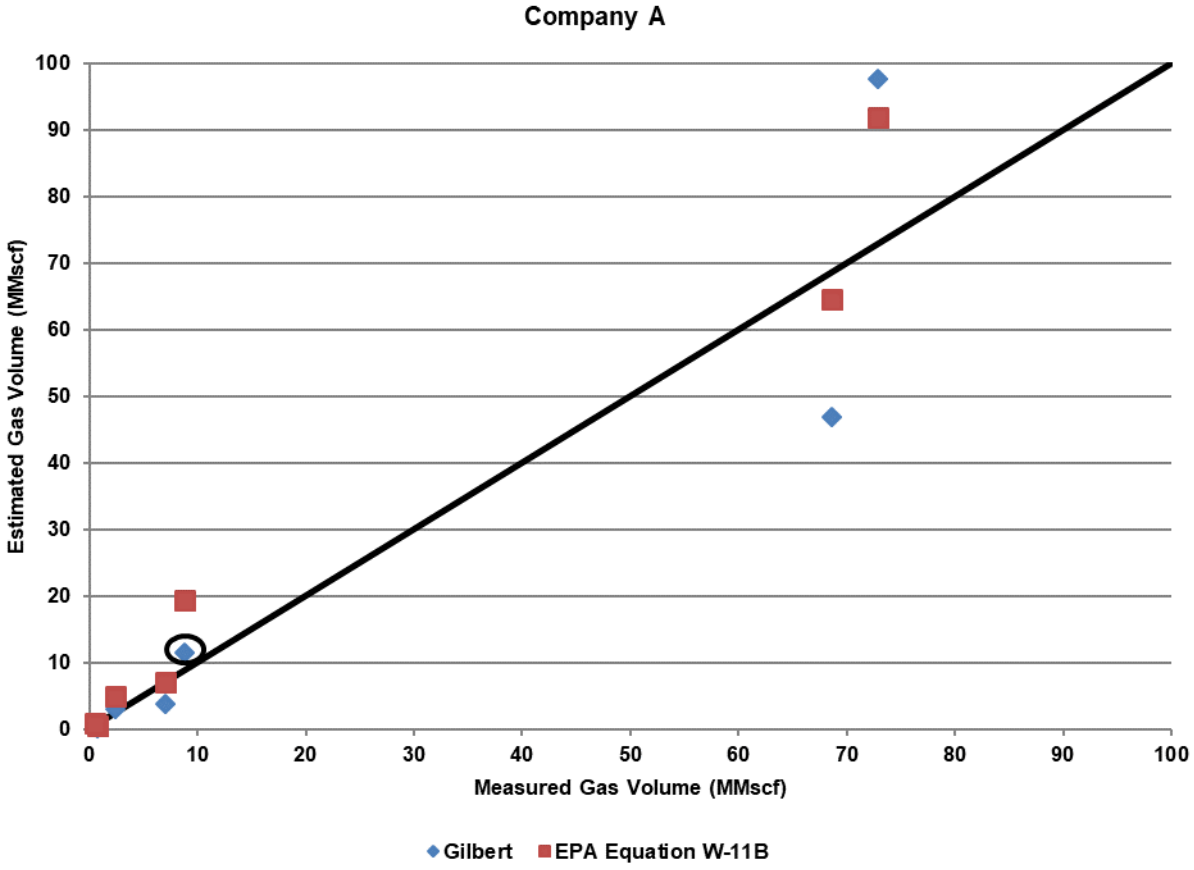

Figure F-2. Parity plot for estimation of gas emissions by Gilbert-Type correlation using field-wide coefficients and EPA Equation W-11B (Company A)

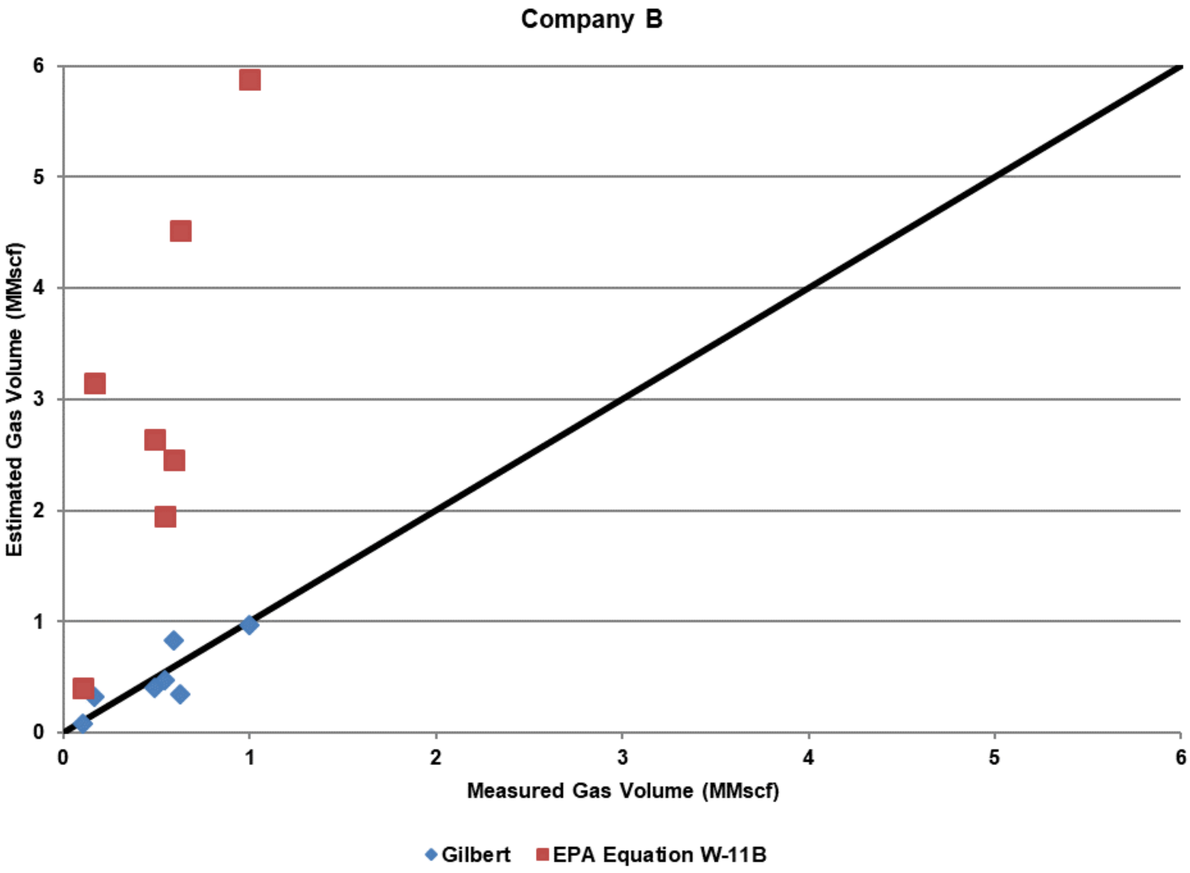

Figure F-3. Parity plot for estimation of gas emissions by Gilbert-Type correlation using field-wide coefficients and EPA Equation W-11B (Company B)

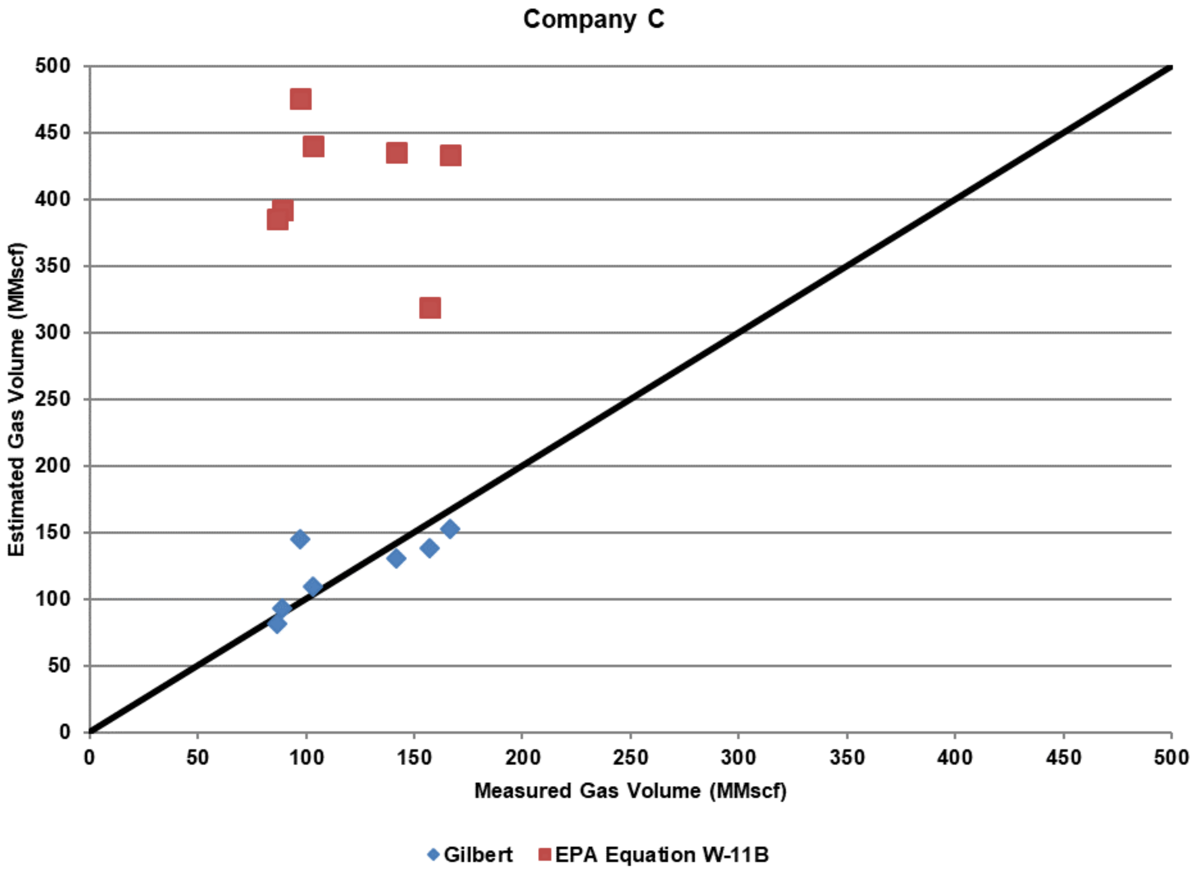

Figure F-4. Parity plot for estimation of gas emissions by Gilbert-Type correlation using field-wide coefficients and EPA Equation W-11B (Company C)

Figures F-5 and F-6 express data from Company A from a different perspective, but they confirm the observations outlined above in the parity plots. These figures display the hourly instantaneous gas flow rate (in units of Mscf per day, on the y-axis) as a function of flowback time (in hours, on the x-axis). There are three simultaneous plots on each figure:

1. The actual gas flow rate measured and recorded by Company A
2. The gas flow rate estimated using the Gilbert-type correlation (Equation F-12) and by applying the hourly values for liquid flow rate (in bbl/day equivalent), upstream pressure, and choke size along with the *a*/*b*/*c* coefficients regressed from the subset of wells.
3. The gas flow rate estimated using EPA Equation W-11B (Equation F-2) and by applying the hourly values for choke size and upstream temperature. The actual flow rate was then converted to a standard flowrate using EPA Equation W-34 (Equation F-4).

Both Figures F-5 and F-6, which represent hourly plots for Wells 1 and 9, respectively, show that application of the Gilbert-type correlation is more accurate than EPA Equation W-11B.

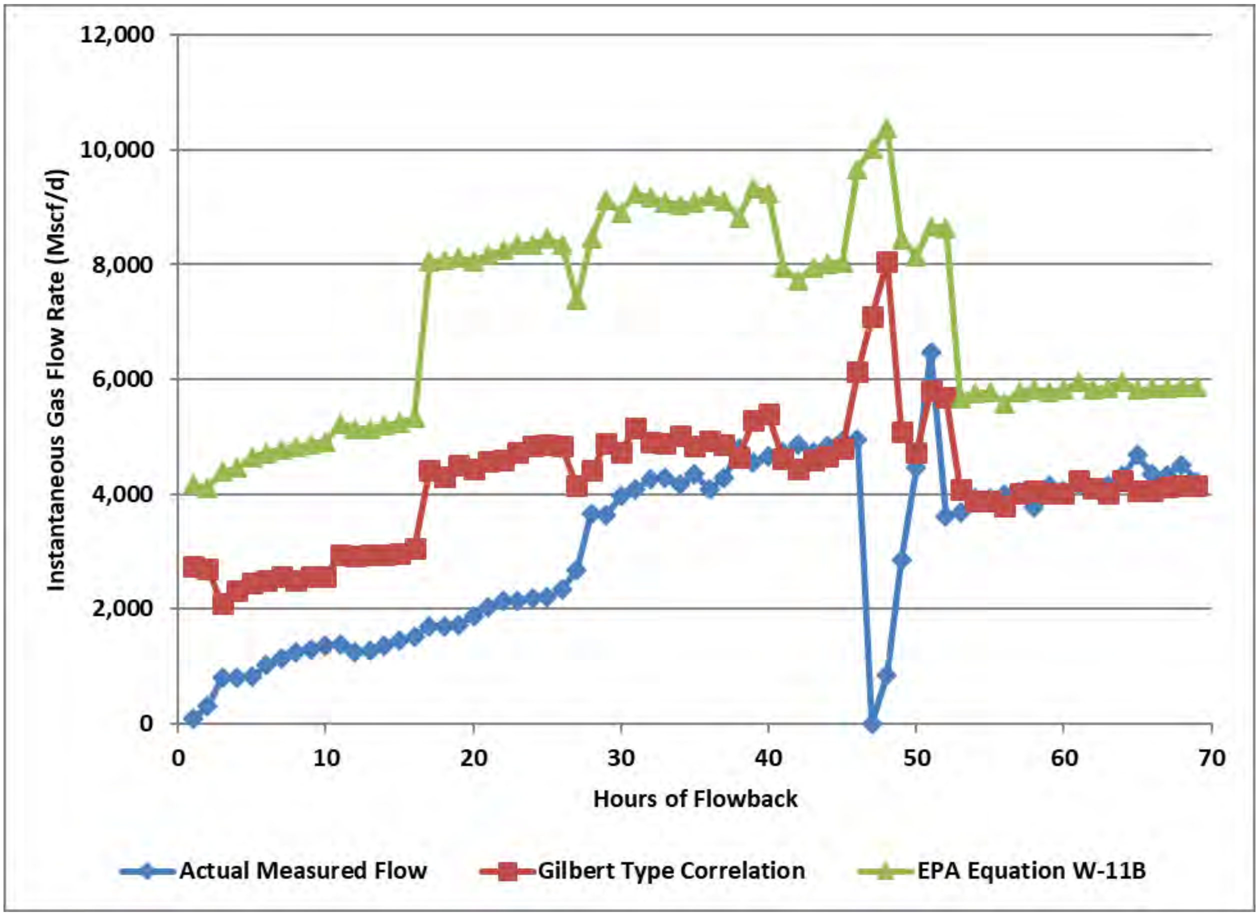

Figure F-5. Hourly estimation of produced gas emissions by Gilbert-Type correlation using field-wide coefficients and EPA Equation W-11B (Company A, Well 1).

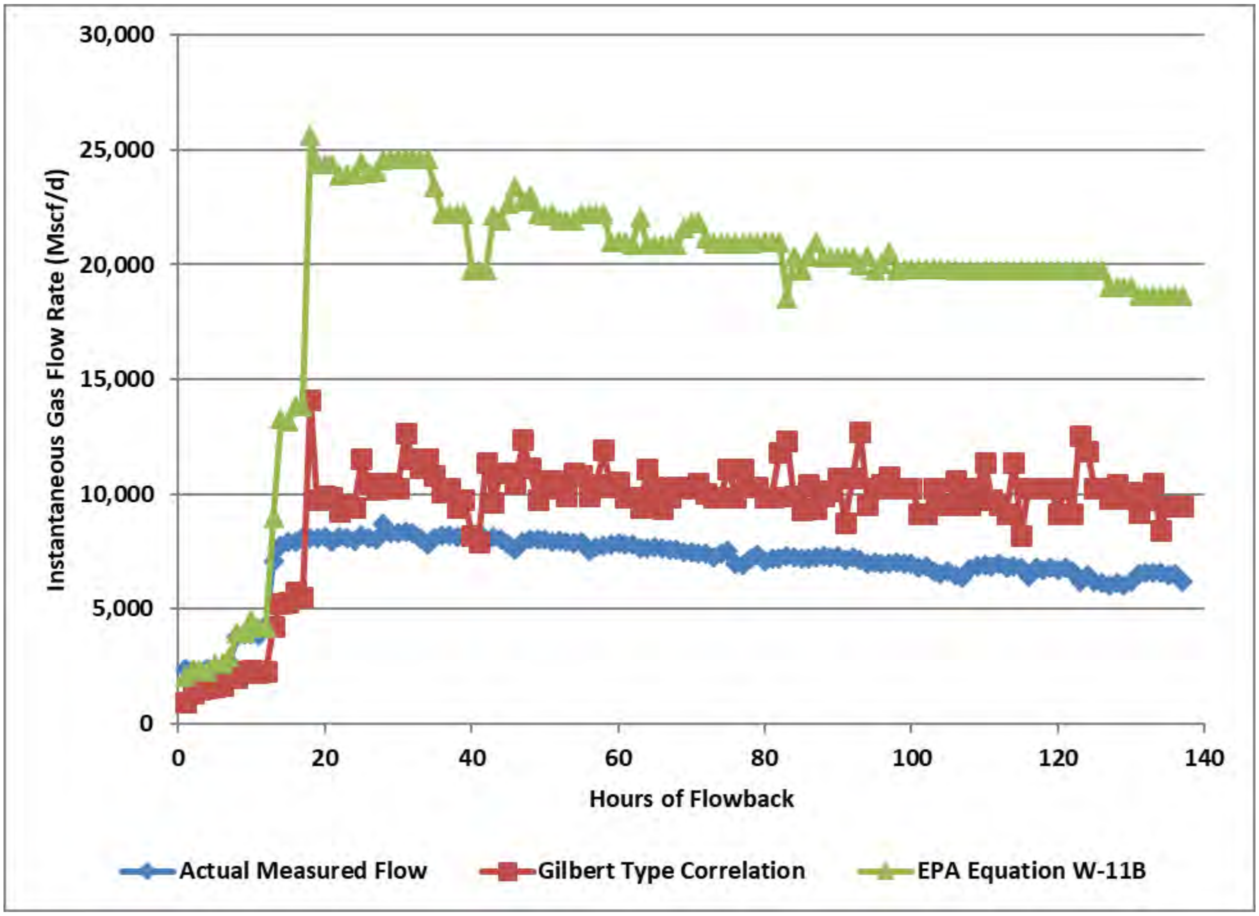

Figure F-6. Hourly estimation of produced gas emissions by Gilbert-Type correlation using field-wide coefficients and EPA Equation W-11B (Company A, Well 9)

F.7 Applicability as a Predictive Tool (Undisclosed Basin)

In order for an empirical equation to be considered as an acceptable tool for industry, it is necessary to demonstrate that the equation is effective as a predictive tool. The proposed approach involves regressing data from a small subset of wells to develop one representative set of *a*/*b*/*c* coefficients for all of the wells in the field. Once the representative field-wide coefficients are determined, the only additional data that are required to calculate the predicted gas volume from other wells in the field are flowback average values for the tubing pressure and choke size, the cumulative volume of produced liquid, and the flowback duration (the latter two values are used to calculate an overall daily average rate of liquids accumulation). No further regression analysis is required for wells beyond those in the subset used to derive the field-wide coefficients.

Independent gas wells were selected from Company A, B and C to test the efficacy of the Gilbert-type correlation as a predictive tool. Trimeric used data from the three remaining gas wells supplied by each company that were not included in the development of the company-specific, field-wide coefficients and evaluated the efficacy of the Gilbert-type correlation for these nine independent sets of flowback data using the company-specific, field-wide sets of *a/b/c* coefficients.

Using the data to estimate one flowback average upstream pressure, one flowback average choke size and one flowback average liquid production rate expressed on a daily rate basis (determined by dividing the cumulative liquid production for the entire flowback by the duration of the flowback) for each well, Trimeric predicted the daily average gas production rate and compared it to the daily average measured gas production rate for each well. The average daily gas production rates were then multiplied by the total days of flowback in order to predict a cumulative gas volume. Trimeric then compared the results of the Gilbert-type correlation to EPA Equation W-11B for these wells.

When using the Gilbert-type correlation as a predictive tool, the predicted gas volume is within 10%, 10%, and 21% of the measured gas volume for the Company A, Company B, and Company C data sets, respectively; for Company B, the Gilbert-type correlation under-predicted the gas volume, while for Companies A and C the Gilbert-type correlation over-predicted the gas volume. For these same sets of independent well data, EPA Equation W-11B overestimates the volume of produced gas by 50% to 350%.

Figures F-7 through F-9 provide parity plots that illustrate the comparison of the cumulative measured gas volume to the cumulative predicted gas volume using the Gilbert-type correlation for the subset of wells used in developing the a/b/c coefficients (labeled as the "dependent" set of wells), and the wells external from the subset used in the predictive analysis (labeled as the "independent" set of wells). These parity plots reaffirm that although the estimate of gas volume using the Gilbert-type correlation for the dependent set of wells is better than the prediction for the independent set of wells, the prediction for the independent wells is accurate as well.

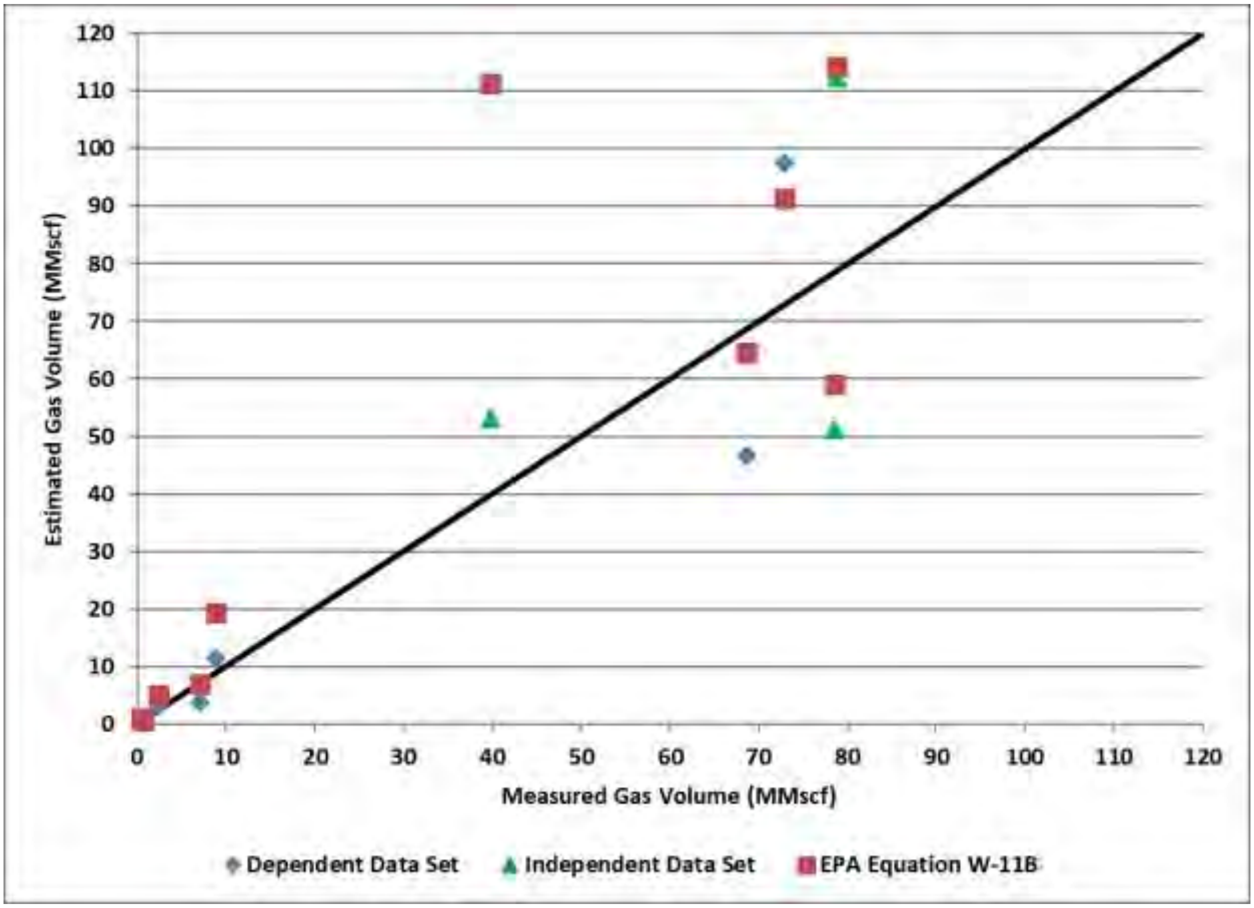

Figure F-7. Parity plot for prediction of gas produced during flowback operations for independent and dependent data sets by Gilbert-Type correlation using field-wide coefficients versus EPA Equation W-11B (Company A)

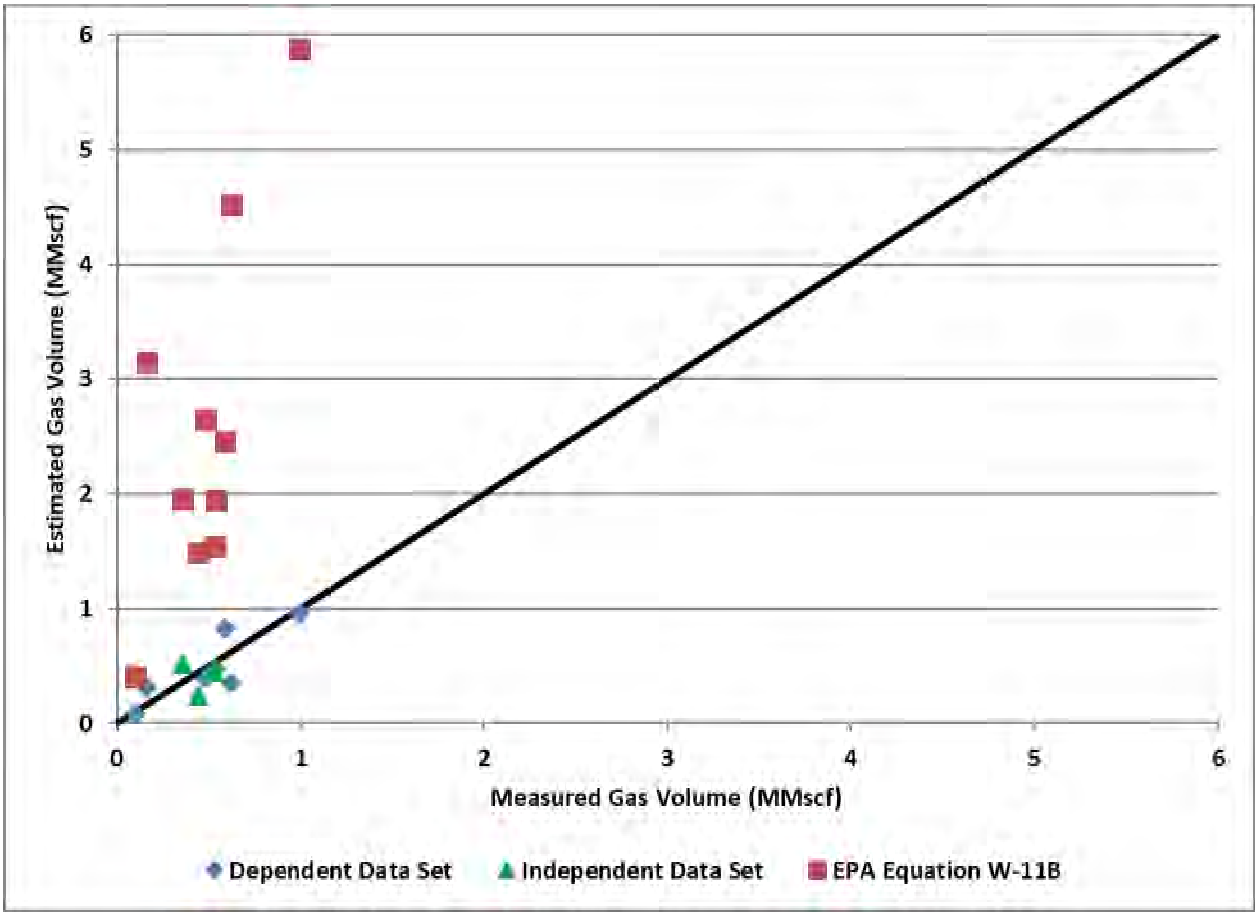

Figure F-8. Parity plot for prediction of gas produced during flowback operations for independent and dependent data sets by Gilbert-Type correlation using field-wide coefficients versus EPA Equation W-11B (Company B)

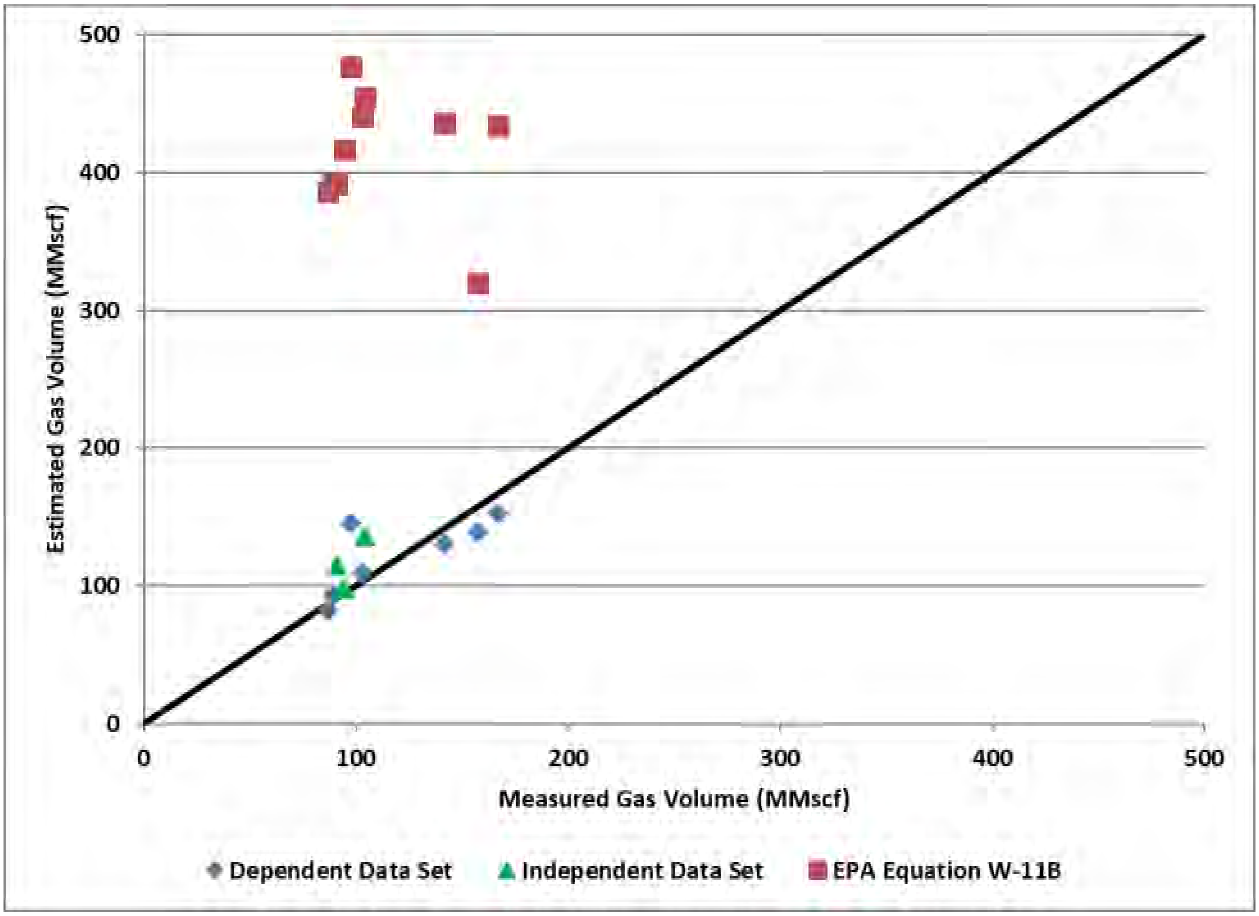

Figure F-9. Parity plot for prediction of gas produced during flowback operations for independent and dependent data sets by Gilbert-Type correlation using field-wide coefficients versus EPA Equation W-11B (Company C)

F.8 Applicability as Predictive Tool (DJ Basin)

In order to test the efficacy of the Gilbert-type correlation as a predictive tool in oil-producing wells in the DJ basin, 10 additional sets of flowback data from other oil wells in the DJ Basin were analyzed in conjunction with the previous field-wide set of *a/b/c* coefficients developed using the original set of 10 oil wells. Using the data for the 10 additional wells to estimate one flowback average upstream pressure, one flowback average choke size and one flowback average of liquid production expressed on a daily rate basis for each of the 10 additional wells, Trimeric estimated the predicted total volume of produced gas using the field-wide coefficients derived from the original 10 wells and compared it to the measured total volume of produced gas.

Tables F-3 and F-4 detail work that was performed as part of the previous evaluation for Noble that preceded this project; when one set of field-wide Gilbert-type a, b and c coefficients was applied to the same 10 wells that were used to develop the field-wide coefficients. As shown in Table F-3, the total error for the comparison of the cumulative estimated gas volume versus the cumulative measured gas volume is approximately 3% for all 10 wells. Table F-4 compares the cumulative measured gas volume in the field to the cumulative estimated gas volume using EPA Equation W-11B; as was shown in the prior evaluation, this total error is approximately 98%.

Table F-3. Estimation of gas emissions using field-regressed coefficients for dependent wells used to develop coefficients

Site	Measured (MMscf)	Predicted (MMscf) – Field-Wide Regressed Correlation	Error (%)
Noble Well 1	81	100	24
Noble Well 2	100	92	-8
Noble Well 3	58	46	-20
Noble Well 4	27	20	-25
Noble Well 5	37	36	-3
Noble Well 6	79	89	12
Noble Well 7	144	130	-9
Noble Well 8	62	75	21
Noble Well 9	59	84	43
Noble Well 10	47	46	-3
Average of Absolute Error			**17**
Field Total / Error Value	**694**	**718**	**3**

Table F-4. Comparison of measured gas emissions with EPA Eq. W-11B

Site	Measured (MMscf)	EPA Eq. W-11B (MMscf)	Error (%)
Noble Well 1	81	188	133
Noble Well 2	100	177	78
Noble Well 3	58	94	61
Noble Well 4	27	59	118
Noble Well 5	37	77	106
Noble Well 6	79	177	123
Noble Well 7	144	214	49
Noble Well 8	62	152	144
Noble Well 9	59	145	145
Noble Well 10	47	90	89
Average Error			**105**

Field Total / Error Value	**694**	**1,373**	**98**

Table F-5 illustrates the results of applying Equation F-12 and the previously developed field-wide *a/b/c* coefficients to 10 independent wells that were not used to develop the representative field-wide coefficients; this most recent analysis shows that the total error for the comparison of the cumulative predicted gas volume versus the cumulative measured gas volume is approximately 16% for these 10 independent wells.

Table F-5. Prediction of gas emissions using field-regressed coefficients for independent wells not used to develop coefficients

Site	**Measured (MMscf)**	**Predicted (MMscf) – Field-Wide Regressed Correlation**	**Error %**
Noble Well 14	18	18	-2
Noble Well 15	40	36	-10
Noble Well 16	33	22	-32
Noble Well 17	53	43	-19
Noble Well 18	13	6	-55
Noble Well 19	11	17	54
Noble Well 20	33	55	67
Noble Well 21	11	20	73
Noble Well 22	2	13	493
Noble Well 23	109	43	-60
Average of Absolute Error Values			87
Field Total / Error Value	**324**	**273**	**-16**

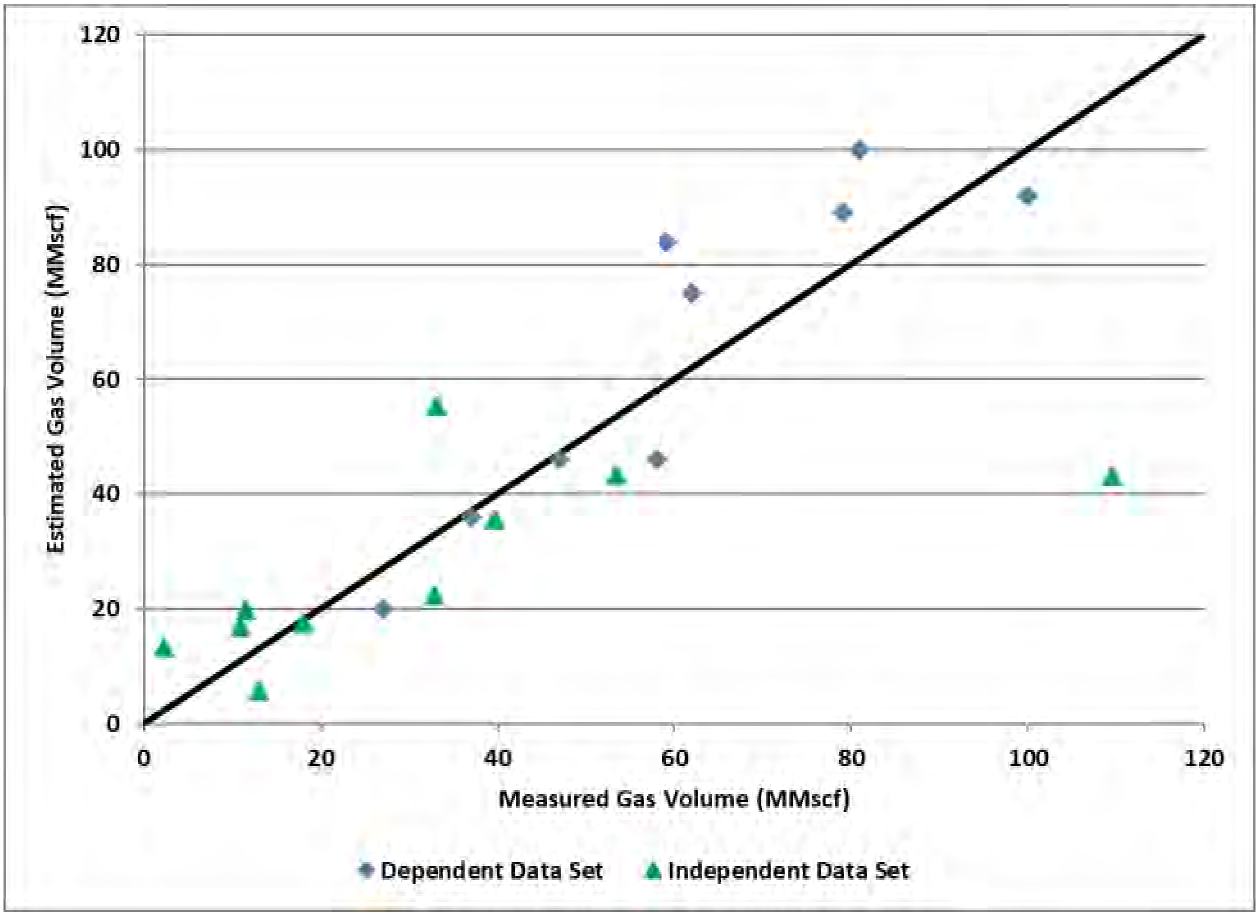

Figure F-10. Parity plot for estimation of gas produced during flowback operations for independent and dependent data sets (Noble)

Figure F-10 provides a parity plot that illustrates the comparison of the cumulative measured gas volume to the cumulative estimated gas volume for the subset of wells used in developing the a/b/c coefficients (labeled as the "dependent" set of wells), and the wells external from the subset used in the predictive analysis (labeled as the "independent" set of wells).

With the exception of one outlier in the independent set of wells, the quality of the fit is similar for the dependent and independent sets.

Trimeric then compared the results of the Gilbert-type correlation for these 10 independent wells to EPA Equation W-11B, which estimates the volumetric gas flow rate as a function of average upstream temperature and average choke size; these results are provided in Table F-6. Table F-6 shows that similar to the conclusion reached in the prior Noble work, EPA Equation W-11B overestimates the cumulative gas volume both for individual wells and for the total field; for the 10 independent wells, EPA Equation W-11B overestimates the cumulative gas volume by 75%.

Figure F-11 provides a parity plot that compares the use of EPA Equation W-11B to the Gilbert-type correlation for these 10 independent wells and graphically represents the overestimation using the standard EPA equation, as nine of the ten data points that represent the estimated gas volume using EPA Equation W-11B (noted in red squares) are located above the "x=y" line. On the other hand, the predicted gas volume using the Gilbert-type correlation has a more uniform distribution around the "x=y"line.

Table F-6. Estimation of gas emissions using EPA Eq. W-11B for independent wells not used to develop coefficients

Site	Measured (MMscf)	EPA Eq. W-11B (MMscf)	Error %
Noble Well 14	18	36	198
Noble Well 15	40	69	147
Noble Well 16	33	54	129
Noble Well 17	53	86	124
Noble Well 18	13	17	58
Noble Well 19	11	33	398
Noble Well 20	33	107	443
Noble Well 21	11	38	471
Noble Well 22	2	32	2,673
Noble Well 23	109	94	-28
Average of Absolute Error Values			467
Field Total / Error Value	**324**	**566**	75

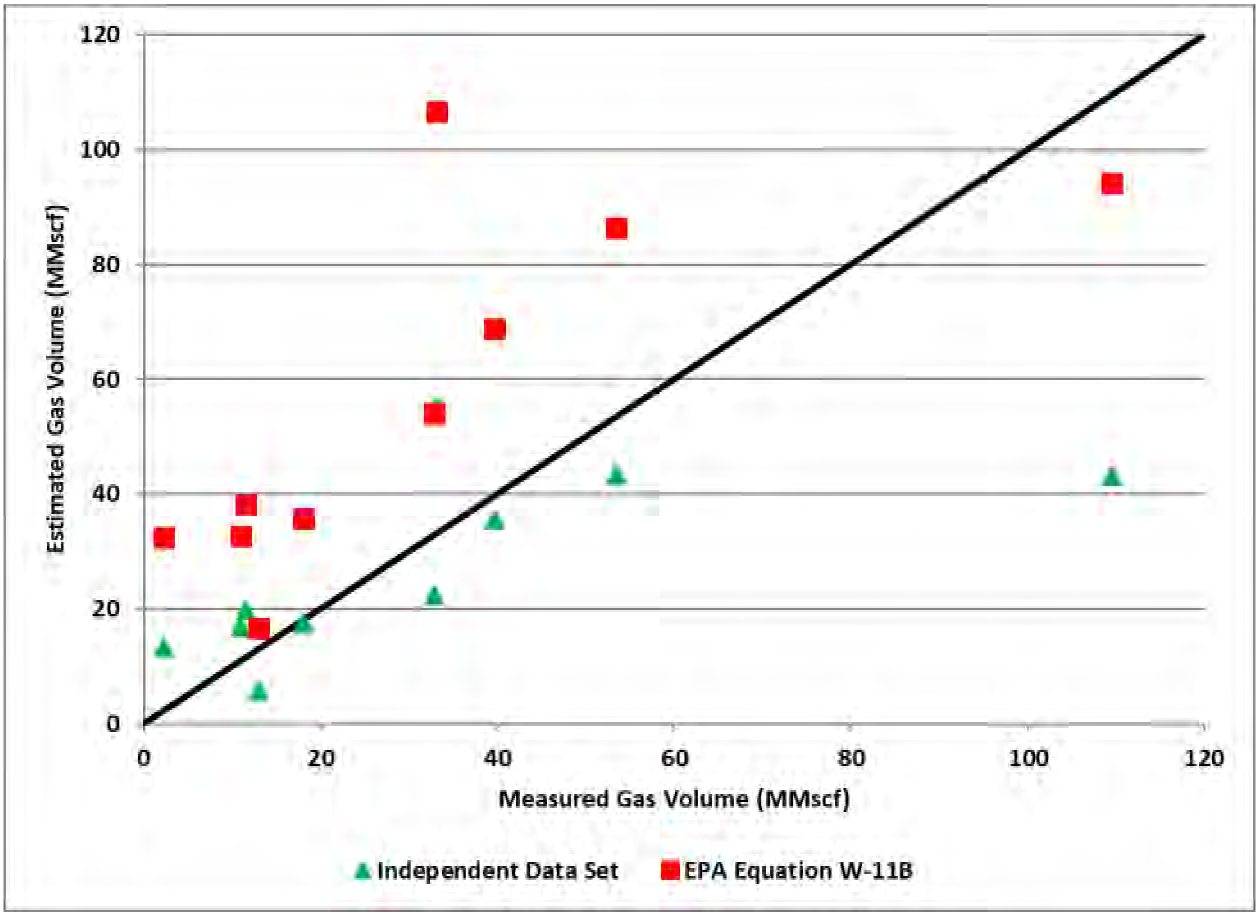

Figure F-11. Parity plot for prediction of gas emissions for independent wells using Gilbert-Type Correlation and EPA Equation W-11B

F.9 Conclusions

Major conclusions from this evaluation are as follows:

- When the Gilbert-type correlation was used for the subset of wells used to develop the a/b/c coefficients, the correlation estimates the field-total cumulative gas volume within 1% to 3% of the measured volume for four sets of wells from different oil and natural gas producers; when the Gilbert-type correlation was used for wells external from the subset to predict the cumulative gas volume, the correlation predicts the cumulative gas volume within 10% to 21%. For these same four sets of wells, EPA Equation W-11B in 40 CFR 98 estimates the cumulative gas volume within 18% to 497%; for three of the four sets of wells, EPA Equation W-11B overestimates the cumulative gas volume by 75% or more.
- The Gilbert-type correlation enables data from a subset of representative flowbacks to be used to develop coefficients that can then be used to predict gas emissions for additional flowbacks in the same field.

- The Gilbert-type correlation can be used effectively to estimate the volume of gas produced for wells producing gas, oil and water (oil wells), and for wells producing only gas and water (gas wells).
- The Gilbert-type correlation can be used effectively for a variety of flowback types such as from several different oil and natural gas producers, with different operating conditions.

The data input requirements for the Gilbert-type correlation are sufficiently similar to the data collection requirements in Subpart W and include measured hourly raw data of cumulative gas produced, cumulative water produced, cumulative oil produced, choke size, and tubing pressure for multiple wells within a field. Once the Gilbert-type coefficients have been determined through the regression analysis, one flowback average upstream pressure, one flowback average choke size, one flowback average liquid production rate expressed on a daily rate basis (determined by dividing the cumulative liquid production for the entire flowback by the duration of the flowback), and the length of the flowback (in days) are all that is required to predict the total volume of produced gas emissions for other flowback operations in the field. This approach can provide more accurate estimates of produced gas and potentially reduce the burden of data collection and reporting for the oil and natural gas producer.

The use of a multiphase flow correlation results in significant improvement in the accuracy of estimated emissions when compared to the single phase equation specified by the EPA, and we suggest that EPA amend Subpart W to allow the use of this alternative and other equally-accurate alternative methods.

Based upon analysis performed in this report, data from a representative set of seven to ten wells is a satisfactory sample size to develop Gilbert-type coefficients that can be used a predictive tool for other wells in the field for an individual oil and natural gas producer. Furthermore, data from other API member companies suggests that existing historical data could potentially be used to develop these coefficients; it may not be necessary for an individual oil and natural gas producer to collect new data to utilize this method. In addition to providing an accurate estimate of GHG emissions, this could also potentially provide more realistic estimates of GHG emissions from flowback operations in specific oil and natural gas fields.

F.10 Nomenclature

a = empirically derived coefficient

A = orifice cross-sectional area, m^2

b = empirically derived coefficient

B = gross liquid rate, barrels per day

c = empirically derived coefficient

$E_{a,i}$ = volumetric gas emissions at actual temperature and pressure, ft^3/hr

$E_{s,i}$ = volumetric gas emissions at standard temperature and pressure, ft^3/hr

FR_a = actual average gas flow rate, ft^3/hr

P = upstream pressure, psia

P' = upstream pressure, psig

P_a = pressure at actual emission conditions, psia

P_s = standard pressure, psia (use value of 14.7 psia)

P_1 = upstream pressure, psia

P_2 = downstream pressure, psia

Q_G = gross gas rate, Mscf per day

Q_L = gross liquid rate, barrels per day

r = gas to liquid ratio, Mcf/bbl

R = gas to liquid ratio, Mscf/bbl

R' = Pressure Ratio, dimensionless

S = bean (choke) size in 1/64th inch increments

T_a = temperature at actual emission conditions, °F

T_s = standard temperature, °F (use value of 60°F)

T_u = upstream temperature, degrees Kelvin

F.11 References

1. Gilbert, W.E. 1954. Flowing and gas-lift well performance. *API Drilling and Production Practice*.
2. Sexton, A., Hinman, L., McKaskle, R., & Fisher, K. (2014). Proposed Alternative Method for Calculating Emissions From Hydraulic Fracturing Operations. SPE Economics & Management, (Preprint).

Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Natural Gas and Oil Industry

Appendix G – Glossary

November 2021

GLOSSARY

Acid Gas

The hydrogen sulfide and/or carbon dioxide contained in or extracted from gas or other streams (GPSA, 1987). *See also sour gas.*

Acid Gas Removal Unit (AGR)

Systems used to remove acid gases (hydrogen sulfide and carbon dioxide) by contracting the stream with a solvent (usually amines) and then driving the absorbed components from the solvent. The amines can also absorb methane and, therefore, methane can be released to the atmosphere through the reboiler vent (Shires and Harrison, 1996).

Accuracy

A measure of the total error associated with a data value, accounting for both random and bias errors (Williamson, Hall, and Harrison, 1996).

Activity Factor

The numeric value representing any action or operation that causes or influences the release of greenhouse gas emissions (e.g., amount of fuel consumed or counts of emission sources); absolute greenhouse gas emissions result when related to the rate of emissions from the action.

Actual Conditions

Temperature, pressure, and volume at measurement conditions.

Aerobic

Referring to a condition or a situation or a living creature, such as a bacteria, in which oxygen is required to sustain life (Schlumberger).

Anaerobic

Pertaining to systems, reactions or life processes of species, such as bacteria, in which atmospheric oxygen is not present or not required for survival (Schlumberger).

Anaerobic Digester

The equipment designed and operated for waste stabilization by the microbial reduction (using acid forming and CH_4 forming bacteria, in the absence of oxygen) of complex organic compounds to CO_2 and CH_4. The produced CH_4 may be captured for use as a fuel or flared (CIWMB, 2008).

API Gravity

A scale used to reflect the specific gravity (SG) of a fluid such as crude oil, water, or natural gas. The API gravity is calculated as [(141.5/SG) - 131.5], where SG is the specific gravity of the fluid at 60°F (Schlumberger).

Associated Gas

Natural gas which is found in association with crude oil either dissolved in the oil or as a cap of free gas above the oil (EIA, 2008).

Auto-refrigeration

The process in which LNG is kept at its boiling point, so that any added heat is countered by energy lost from boil off.

Ballasting Emissions

Evaporative emissions associated with the unloading of petroleum liquids at marine terminals. The emissions occur when vapor-laden air in an "empty" cargo tank is displaced to the atmosphere by ballast water being pumped into the tank to improve the stability of the marine tanker (EPA, AP-42, 1995-2000).

Barrel 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. This quantity will vary depending on the heating value of crude. For example, according to the US Internal Revenue Service (IRS), a BOE is any amount of fuel which has 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.

Bitumen

A thick, black, high-sulfur, heavy oil extracted from tar sand and then upgraded to synthetic fuel oil. Bitumen includes hydrocarbons such as asphalt and mineral wax (Schlumberger).

Bituminous Coal

A dense, black, soft coal, often with well defined bands of bright and dull material. The most common coal, with moisture content usually less than 20 percent. Used for generating electricity, making coke, and space heating (EIA, 2008).

Biomass

Non-fossilized and biodegradable organic material originating from plants, animals and microorganisms, including products, by-products, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material (TCR, 2008).

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 (Schlumberger).

Blowdown

The act of emptying or depressuring a vessel. This may also refer to the discarded material such as blowdown water from a boiler or cooling tower (GPSA, 1987).

Blowout

An uncontrolled flow of well fluids and/or formation fluids from the wellbore or into lower pressured subsurface zones (underground blowout) (API, 1988).

British Thermal Unit (Btu)

A measure of heat energy required to raise the temperature of one pound of water by one degree Fahrenheit. British thermal unit is abbreviated as Btu (Schlumberger).

Bunker Fuel

Fuel supplied to ships (marine bunker fuel) and aircraft (aviation bunker fuel) consisting primarily of residual and distillate fuels for marine sources and jet fuel for aviation sources. Thus, the CO_2 emission factors listed in Table 4-3 can be used for marine and aviation bunker fuels (EIA, 2008).

Ci+

Refers to a natural gas fraction consisting of hydrocarbon molecules "*i*" and heavier. For example, C6+ is the natural gas fraction of hydrocarbon molecules hexane and heavier.

Carbon Capture and Storage

A process consisting of separation of CO_2 from industrial and energy-related sources, transport to a storage location, and long-term isolation from the atmosphere (IPCC).

Carbon Dioxide (CO_2)

A colorless, odorless, non-toxic gas that is a normal component of ambient air. Carbon dioxide is a product of fossil fuel combustion (API, 1988). Although CO_2 does not directly impair human health, it is a GHG that traps terrestrial (i.e. infrared) radiation and contributes to the potential for global warming.

Carbon Dioxide Equivalent (CO_2e)

The mass of a GHG species multiplied by the global warming potential (GWP) for that species. It is used to evaluate emissions of different GHGs on a common basis—the mass of CO_2 emitted that would have an equivalent warming effect (IPIECA, 2003).

Carbon Equivalent

Determined by first multiplying the total mass of a GHG gas species by the global warming potential for that species, which converts the units to a mass of CO_2 basis. Then the CO_2 mass units are converted to carbon based on the molecular weight ratio of carbon to CO_2. Exhibit 3.1 provides an example of this calculation.

Casinghead Gas

Natural gas produced along with crude oil from oil wells. It contains either dissolved or associated gas or both (EIA).

Catalyst Coke

In many catalytic operations (e.g., catalytic cracking), carbon is deposited on the catalyst, thus deactivating the catalyst. The catalyst is reactivated by burning off the carbon, which is used as a fuel in the refining process. This carbon or coke is not recoverable in a concentrated form (EIA).

Catalytic Cracking Unit

A refinery process unit in which petroleum derivatives are continuously charged and hydrocarbon molecules in the presence of a catalyst are fractured into smaller molecules, or react with a contact material suspended in a fluidized bed to improve feedstock quality for additional processing and the catalyst or contact material is continuously regenerated by burning off coke and other deposits. Catalytic cracking units include both fluidized bed systems, which are referred to as fluid catalytic cracking units (FCCU), and moving bed systems, which are also referred to as thermal catalytic cracking units. The unit includes the riser, reactor, regenerator, air blowers, spent catalyst or contact material stripper, catalyst or contact material recovery equipment, and regenerator equipment for controlling air pollutant emissions and for heat recovery (EIA).

Centrifugal Compressor

Any equipment that increases the pressure of a gas stream by centrifugal action, employing rotating movement of the driven shaft (Hyne, 1991).

Centrifugal Compressor Dry Seals

A series of rings that are located around the compressor shaft where it exits the compressor case and that operate mechanically under the opposing forces to prevent natural gas from escaping to the atmosphere (Methane to Markets, 2009).

Centrifugal Compressor Wet Seals

A series of rings around the compressor shaft where it exits the compressor case that use oil circulated under high pressure between the rings to prevent natural gas from escaping to the atmosphere (Methane to Markets, 2009).

Chemical Injection

A general term for injection processes that use special chemical solutions to improve oil and gas operations. Injection can be administered continuously, in batches, in injection wells, or at times in production wells. Some of the chemical solutions used include but are not limited to corrosion inhibitor, scale inhibitor, biocide, demulsifier, clarifier, and hydrate inhibitor. Natural gas powered chemical injection pumps use gas pressure acting on a piston to pump a chemical on the opposite side of the piston. The gas is then vented directly to the atmosphere. Electric powered pumps would be a source of indirect GHG emissions (Schlumberger; Shires, 1996).

Chemical Oxygen Demand (COD)

The amount of oxygen needed to oxidize reactive chemicals in a water system, typically determined by a standardized test procedure. COD is used to estimate the amount of a pollutant in an effluent (Schlumberger).

Coal

A readily combustible black or brownish-black rock whose composition, including inherent moisture, consists of more than 50 percent by weight and more than 70 percent by volume of carbonaceous material. It is formed from plant remains that have been compacted, hardened, chemically altered, and metamorphosed by heat and pressure over geologic time (EIA).

Co-generation unit/Combined Heat and Power (CHP)

Cogeneration, also known as combined heat and power (CHP), is the simultaneous production of energy and process heat from the same fuel.

Coke (Petroleum)

A residue high in carbon content and low in hydrogen that is the final product of thermal decomposition in the condensation process in cracking. This product is reported as marketable coke or catalyst coke (EIA, 2008).

Coke Burn-off

In the regenerator, coke deposited on the catalyst as a result of the cracking reactions is burned off in a controlled combustion process with preheated air. The catalyst is then recycled to be mixed with fresh hydrocarbon feed (EPA, 1998(b)).

Combined Cycle

An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for utilization by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit (EIA).

Commercial Combustor

Refers to commercial boilers/furnaces with Source Classification Codes (SCCs) 1-03-004-01/02/03/04 and 1-03-005-01/02/03/04. According to 40 CFR 63.7575 (December 6, 2006), a *commercial/institutional boiler* means a boiler used in commercial establishments or institutional establishments such as medical centers, research centers, institutions of higher education, hotels, and laundries to provide electricity, steam, and/or hot water. A previous edition (4th edition) of AP-42 defined a natural gas or liquefied petroleum gas fired commercial boiler as a boiler with a heat input capacity between 0.3 and 10 MMBtu/hr (EPA, 1985 to 1993).

Component

Sealed surfaces of above-ground process equipment, including valves, flanges, and other connectors, pump seals, compressor seals, pressure relief valves, open-ended lines, and sampling connections. These components represent mechanical joints, seals, and rotating surfaces, which in time tend to wear and develop unintentional leaks (Hummel, Campbell, and Harrison, 1996).

Compressor

A device that raises the pressure of air or natural gas. A compressor normally uses positive displacement to compress the gas to higher pressures so that the gas can flow into pipelines and other facilities (Schlumberger).

Condensate

Liquid formed by the condensation of a liquid or gas; specifically, the hydrocarbon liquid separated from natural gas because of changes in temperature and pressure when the gas from the reservoir was delivered to the surface separators. Such condensate remains liquid at atmospheric temperature and pressure.

Connector

Any threaded or non-threaded union or joint associated with pipeline segments, tubing, piece of attached equipment or an instrument. These include but are not limited to flanges, elbows, reducers, "T's", or valves. These are potential sources for fugitive emissions (Schlumberger; Hummel, Campbell, and Harrison, 1996).

Cracking

The process of splitting a large heavy hydrocarbon molecule into smaller, lighter components. The process involves very high temperature and pressure and can involve a chemical catalyst to improve the process efficiency (Schlumberger).

Crude Oil

A mixture of hydrocarbons that exists in the liquid phase in the underground reservoir and remains liquid at atmospheric pressure after passing through surface separating facilities (API, 1988).

Cryogenic Liquid or Cryogens

Cryogenic liquids (cryogens) are liquefied gases that are kept in their liquid state at very low temperatures and have a normal boiling point below -238 °F(-150 °C). All cryogenic liquids are gases at normal temperatures and pressures. Examples of cryogens include methane, oxygen, nitrogen, helium and hydrogen. Additional information on cryogens is available from the Canadian Centre for Occupational Health and Safety (CCOHS).

Dehydrator

A device used to remove water and water vapors from gas, including but not limited to desiccant, ethylene glycol, diethylene glycol, or triethylene glycol (Schlumberger).

Delayed Coking Unit

One or more refinery process units in which high molecular weight petroleum derivatives are thermally cracked under elevated temperatures and pressure to produce petroleum coke in a series of closed, batch system reactors (EIA).

Destruction efficiency

The extent to which a target substance present in the input combustibles has been fully oxidized or converted to environmentally safer chemicals (e.g., CH_4 to CO_2, H_2S to SO_2, ammonia/NH_3 to N_2) released into the atmosphere (Methane to Markets, 2009).

Diaphragm Chemical Injection Pump (CIP)

A small positive displacement, reciprocating unit designed to inject precise amounts of chemicals into process streams using a flexible diaphragm to move the plunger.

Diesel Fuel

A fuel composed of distillates obtained in petroleum refining operation or blends of such distillates with residual oil used in motor vehicles. The boiling point and specific gravity are higher for diesel fuels than for gasoline (EIA).

Dig-in

Ruptures of pipelines caused by unintentional (often third-party) damage (Shires and Harrison, 1996).

Direct Emissions

Emissions from sources within the reporting entity's organizational boundaries that are owned or controlled by the reporting entity, including stationary combustion emissions, mobile combustion emissions, process emissions, and fugitive emissions (TCR, 2008).

Distillate Oil

A general classification for one of the petroleum fractions produced in conventional distillation operations. It includes diesel fuels and fuel oils. Products known as no. 1, no. 2, and no. 4 diesel fuel are used in on-highway diesel engines, such as those in trucks and automobiles, as well as off-highway engines, such as those in railroad locomotives and agricultural machinery. Products known as no. 1, no. 2, and no. 4 fuel oils are used primarily for space heating and electric power generation (EIA).

Downstream

Operations involving the refining, processing, distribution and marketing of products derived from oil and gas, including service stations (IPIECA, 2003).

Dry Gas

(1) Gas whose water content has been reduced by a dehydration process. (2) Gas containing little or no hydrocarbons commercially recoverable as liquid product. Gas in this second definition preferably should be called "lean gas" (GPSA).

Emergency generator

A stationary internal combustion engine that serves solely as a secondary source of mechanical or electrical power whenever the primary energy supply is disrupted or discontinued (EIA; Hynes, 1991).

Emergency Shutdown (ESD)

The emergency procedure of depressuring equipment. The gas may be vented to the atmosphere or routed to a flare.

Emission Factor

The rate of emission per unit of activity, output or input (IPCC).

Emissions

The intentional or unintentional release of greenhouse gases into the atmosphere (IPIECA, 2003).

Engineering Estimate

An estimate of emissions based on engineering principles applied to measured and/or approximated physical parameters. Engineering estimate can also refer to estimated fuel use based on engine run time, load, heat rate curve, and fuel characteristics.

Enhanced Oil Recovery (EOR)

Artificial methods used to recover more oil after primary production by the natural reservoir drive and, possibly, water-flooding. Common EOR methods include thermal (cyclic steam stimulation, stream-flooding, and in-situ combustion), chemical (polymer, micellarpolymer, and alkaline flooding), and gas miscible (cyclic, carbon-dioxide stimulation, carbon-dioxide flooding, and nitrogen flooding). Due to potentially high CO_2 concentrations associated with EOR operations, CO_2 emissions from vented and fugitive sources should be considered in a greenhouse gas inventory.

External Combustion Device

Steam/electric generating plants, industrial boilers, process heating and space heating, and other commercial and domestic combustion units (EPA, 1998(b)).

Feedstock

A chemical refined and manufactured from hydrocarbons and used to produce petrochemicals. Methane, ethylene, propylene, butylene, and napthenes are common feedstocks (Hyne, 1991).

Floating Production and Storage Offloading (FPSO) System

Similar to an offshore production platform, except that FPSO's are mobile. FPSO's combine production, crude oil storage, and offloading into shuttle tankers. They may also include gas processing (Offshore Technology, 2009).

Fluid Catalytic Cracking Unit (FCCU)

The refining process of breaking down the larger, heavier, and more complex hydrocarbon molecules into simpler and lighter molecules. Catalytic cracking is accomplished by the use of a catalytic agent and is an effective process for increasing the yield of gasoline from crude oil (EIA).

Fluid Coking Unit (FCU)

A thermal cracking process utilizing the fluidized-solids technique to remove carbon (coke) for continuous conversion of heavy, low-grade oils into lighter products (EIA).

Fluorinated Greenhouse Gas

Sulfur hexafluoride (SF_6), nitrogen trifluoride (NF_3), and any fluorocarbon except for controlled substances as defined at 40 CFR Part 82 Subpart A. In addition to SF_6 and NF_3, "fluorinated GHG" includes but is not limited to any hydrofluorocarbon, any perfluorocarbon, any fully fluorinated linear, branched or cyclic alkane, ether, tertiary amine or aminoether, any perfluoropolyether, and any hydrofluoropolyether (EPA, 2006).

Fossil Fuel

Coal, oil, and other natural gas derived from decomposed organic material.

Fuel Gas (Still Gas)

Gas generated at a petroleum refinery, petrochemical plant, or similar industrial process unit, and that is combusted separately or in any combination with any type of gas. This definition does not include natural gas used as a fuel.

Fugitive Emissions

Unintentional releases from piping components and equipment leaks at sealed surfaces, as well as from underground pipeline leaks. Fugitive emissions also include non-point evaporative sources such as from wastewater treatment, pits, and impoundments. (*Compendium*, Section 3.2.3)

Gas/Diesel Oil

Gas oils are obtained from the lowest fraction from atmospheric distillation of crude oil, while heavy gas oils are obtained by vacuum redistillation of the residual from atmospheric distillation. Gas/diesel oil distils between 180ºC and 380ºC. Several grades are available depending on uses: diesel oil for diesel compression ignition (cars, trucks, marine, etc.), light heating oil for industrial and commercial uses, and other gas oil including heavy gas oils which distil between 380ºC and 540ºC and which are used as petrochemical feedstocks (IEA).

Gaseous Fuel

A material that is in the gaseous state at standard atmospheric temperature and pressure conditions and that is combusted to produce heat and/or energy.

Gas Processing Plant

An installation that processes natural gas to recover natural gas liquids (condensate, natural gasoline and liquefied petroleum gas) and sometimes other substances such as sulfur. A gas processing plant is also known as a natural gas processing plant (Schlumberger).

Gas/Oil Ratio (GOR)

The ratio of produced gas to produced oil (Schlumberger).

Gathering Lines

The pipes used to transport oil and gas from a field to the main pipeline in the area (Schlumberger).

Gathering System

The flowline network and process facilities that transport and control the flow of oil or gas from the wells to a main storage facility, processing plant or shipping point. A gathering system includes pumps, headers, separators, emulsion treaters, tanks, regulators, compressors, dehydrators, valves and associated equipment. There are two types of gathering systems, radial and trunk line. The radial type brings all the flowlines to a central header, while the trunk-line type uses several remote headers to collect fluid. The latter is mainly used in large fields. The gathering system is also called the collecting system or gathering facility (Schlumberger).

Global Warming Potential (GWP)

An index used to relate the level of emissions of various greenhouse gases to a common measure. The GWP is defined as the ratio of the amount of global warming or radiative forcing produced by a given gas relative to the global warming produced by the reference gas CO_2, for a specified time period. As the reference gas, CO_2 has a GWP value of 1. GWPs for common GHGs can be found in Table 3-1 (EIA, 2008).

Greenhouse Gas (GHG)

Gaseous constituents of the atmosphere, both natural and anthropogenic, that absorb and emit radiation at specific wavelengths within the spectrum of infrared radiation emitted by the Earth's surface, the atmosphere and clouds. This property causes the greenhouse effect. Water vapor (H_2O), carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4) and ozone (O_3) are the primary GHGs in the earth's atmosphere. Moreover, there are a number of entirely human-made greenhouse gases in the atmosphere, such as the halocarbons and other chlorine and bromine-containing substances, dealt with under the Montreal Protocol. Besides CO_2, N_2O and CH_4, the Kyoto Protocol deals with the GHGs sulfur hexafluoride, hydrofluorocarbons, and perfluorocarbons (IPCC).

Heating Value

The amount of energy released when a fuel is burned completely. See also HHV and LHV (IPIECA, 2003).

Heavy Crude Oil

A category of crude oil characterized by relatively high viscosity, a higher carbon-to-hydrogen ratio, and a relatively higher density. API Report 4638, *Calculation Workbook For Oil and Gas Production Equipment Fugitive Emissions*, designates heavy crude as having an API gravity of less than 20° (API, 1996).

Higher Heating Value (HHV)

The quantity of heat produced by the complete combustion of a unit volume or weight of fuel assuming that the produced water is completely condensed (liquid state) and the heat is recovered. Also referred to as Gross Calorific Value (*Compendium*, Section 3.6.3).

Hydrocarbon

A naturally occurring organic compound comprising hydrogen and carbon. Hydrocarbons can be as simple as methane (CH_4), but many are highly complex molecules, and can occur as gases, liquids or solids. The molecules can have the shape of chains, branching chains, rings or other structures. The most common hydrocarbons are natural gas, oil and coal (Schlumberger).

Hydrofluorocarbon (HFC)

Halocarbons containing only hydrogen, fluorine and carbon atoms. Because HFCs contain no chlorine, bromine, or iodine, they do not deplete the ozone layer. Like other halocarbons, they are potent greenhouse gases (IPCC, 2006).

Indirect Emissions

The release of GHG emissions as a consequence of operations of the reporting company, but physically occurring at sources owned or operated by another organization (e.g., purchased electricity or steam) (IPIECA, 2003).

Industrial Boiler

Source Classification Codes (SCCs) most applicable to the Oil and Gas Industry include: 1-02-004-01/02/03/04/05 (distillate fuel fired units), 1-02-005-01/02/03/04/05 (residual fuel fired units), 1-02-006-01/02/03/04 (natural gas fired units), 1-02-010-01/02/03 (liquefied petroleum gas fired units), and 1-02-007-01/04/07/10/99 (process gas fired units). According to 40 CFR 63.7575 (December 6, 2006), an *Industrial boiler* means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity. A previous edition (4th edition) of AP-42 defined a natural gas fired large industrial boiler as a boiler with a heat input capacity of greater than 100 MMBtu/hr (EPA, 1985 to 1993). The same edition of AP-42 also defined a natural gas fired small industrial boiler and a liquefied petroleum gas fired industrial boiler as a boiler with a heat input capacity between 10 to 100 MMBtu/hr (EPA, 1985 to 1993).

Injection Gas

Gas injected into a formation to maintain or restore reservoir pressure. Other reasons for gas injection are gas-lift operations, cycling in gas-condensate reservoirs or storing gas (Schlumberger).

Internal Combustion Engines

An engine that uses the burning of the air-fuel mixture to provide mechanical shaft power. The major types of IC engines used in petroleum operations are gas turbines and reciprocating engines. Most stationary internal combustion engines are used to generate electric power, to pump gas or other fluids, or to compress air for pneumatic machinery (EIA; Hyne, 1991).

Kimray Pump

A specific type of gas-powered glycol circulation pumps. These pumps use the high pressure of the rich glycol from the absorber to power pistons that pump the low pressure, lean glycol from the regenerator. The pump configuration pulls additional gas from the absorber along with the rich glycol. This gas is emitted through the dehydrator vent stack along with the methane absorbed in the rich glycol stream (Shires and Harrison, 1996).

Lower Heating Value (LHV)

The quantity of heat produced by the complete combustion of a unit volume or weight of fuel assuming that the produced water remains as a vapor and the heat of the vapor is not recovered. The difference between the HHV and LHV is the latent heat of vaporization of the product water (i.e., the LHV is reduced by the enthalpy needed to vaporize liquid water). Also referred to as Net Calorific Value (*Compendium*, Section 3.6.3).

Light Crude Oil

A category of crude oil characterized by relatively low viscosity, a lower carbon-to-hydrogen ratio, and a relatively lower density. API Report 4638, *Calculation Workbook For Oil and Gas Production Equipment Fugitive Emissions*, designates light crude as having an API gravity of greater than 20° (API, 1996). EPA's *Protocol for Equipment Leak Emission Estimates* defines light crude as material in a liquid state in which the sum of the concentration of individual constituents with a vapor pressure over 0.3 kilopascals (kPa) at 20 ^{o}C is greater than or equal to 20 weight percent. (EPA, 1995).

Liquefied Natural Gas (LNG)

Natural gas, mainly methane and ethane, which has been liquefied at cryogenic temperatures. This process occurs at an extremely low temperature and a pressure near the atmospheric pressure (Schlumberger).

Liquefied Petroleum Gas (LPG)

A group of hydrocarbon-based gases derived from crude oil refining or natural gas fractionation. They include ethane, ethylene, propane, propylene, normal butane, butylene, isobutane, and isobutylene. For convenience of transportation, these gases are liquefied through pressurization (EIA, 2008).

Live Crude Oil

Crude oil containing dissolved gas in solution that may be released from solution at surface conditions. Also referred to as unstabilized crude oil (Schlumberger).

Loading Emissions

The hydrocarbon vapors residing in “empty” cargo tanks that are displaced to the atmosphere by liquids being loaded into the tanks.

Lubricants

Substances used to reduce friction between bearing surfaces, or incorporated into other materials used as processing aids in the manufacture of other products, or used as carriers of other materials. Petroleum lubricants may be produced either from distillates or residues. Lubricants include all grades of lubricating oils, from spindle oil to cylinder oil to those used in greases (EIA, 2008).

Material Balance

An expression for conservation of mass governed by the observation that the amount of mass leaving a control volume is equal to the amount of mass entering the volume minus the amount of mass accumulated in the volume (Schlumberger).

Meter and Regulation Station (M&R Station)

A facility whose purpose is to measure the volume of gas passing through a pipeline. A regulation station is a facility whose purpose is to regulate the pressure of gas passing through a pipeline to a set level (CAPP, 2004).

Methane (CH_4)

The lightest and most abundant of the hydrocarbon gases and the principal component of natural gas (Schlumberger). A hydrocarbon that is a greenhouse gas. Methane is released to the atmosphere through anaerobic (without air) decomposition of waste, animal digestion, production and distribution of natural gas and petroleum, coal production, and incomplete fossil fuel combustion (IPCC, 2006).

Miscellaneous Petroleum Products

Includes all refined petroleum products not classified elsewhere. This definition includes petrolatum lube refining by-products (aromatic extracts and tars) absorption oils, ram-jet fuel, petroleum rocket fuels, synthetic natural gas feedstocks, and specialty oils.

Mobile Combustion Sources

Engines providing the motive power for vehicles or marine vessels used in the transport of feedstock or product, construction or maintenance equipment, or in the work-related transport of company personnel.

Natural Gas

A naturally occurring mixture of hydrocarbons and varying quantities of non-hydrocarbons that exists either in the gaseous phase or in solution with crude oil in natural underground reservoirs (API, 1988).

Natural Gas Liquids

Components of natural gas that are liquid at surface in field facilities or in gas-processing plants. Natural gas liquids can be classified according to their vapor pressures as low (condensate), intermediate (natural gasoline) and high (liquefied petroleum gas) vapor pressure. Natural gas liquids include propane, butane, pentane, hexane and heptane, but not methane and ethane, since these hydrocarbons need refrigeration to be liquefied. The term is commonly abbreviated as NGL (Schlumberger).

Natural Gasoline

A term used in the gas processing industry to refer to a mixture of liquid hydrocarbons (mostly pentanes and heavier hydrocarbons) extracted from natural gas with a vapor pressure intermediate between condensate and liquefied petroleum gas. It includes isopentane (Schlumberger).

Natural Gas Processing Facilities

A facility designed (1) to achieve the recovery of natural gas liquids from the stream of natural gas which may not have been processed through lease separators and field facilities, and (2) to control the quality of the natural gas to be marketed (API, 1988).

Natural Gas Products

Products produced for consumers from natural gas processing facilities including, but not limited to, ethane, propane, butane, iso-butane, and pentanes-plus (Hyne, 1992; Schlumberger).

Non-Associated Gas

Natural gas that is not in contact with oil in a subsurface reservoir. Non-associated gas is usually dry gas and is in contrast to associated or dissolved gas (e.g., gas well or unassociated gas) (Hyne, 1991).

Non-Point Sources

A type of emission that includes evaporative sources, such as from wastewater treatment, pits, impoundments, and mine tailing pond surface emissions (*Compendium*, Section 6.0).

Oil/Water Separator

Equipment installed usually at the entrance to a drain, which removes oil and grease from water flows entering the drain. Equipment includes but not limited to gravity separators or ponds and air flotation systems. This definition specifically excludes sumps and storm water ponds (API, 1988).

Open-ended Valve or Lines (OELs)

Any valve, except pressure relief valves, having one side of the valve seat in contact with process fluid and one side open to atmosphere, either directly or through open piping.

Operator

The person, firm, corporation, proprietor or lessee, or any other organization or entity employed by the owners to conduct operations (API, 1988; MMS 2006).

Owner

A word used to designate the company, person, or entity that specifies the type of inspection or testing to be conducted and has the authority to order it performed (API, 1988).

Petrochemicals

The manufacture, distribution, and marketing of chemical products derived from oil and gas (IPIECA, 2003).

Petroleum

A complex mixture of naturally occurring hydrocarbon compounds found in rock. Petroleum can range from solid to gas, but the term is generally used to refer to liquid crude oil. Impurities such as sulfur, oxygen and nitrogen are common in petroleum. There is considerable variation in color, gravity, odor, sulfur content and viscosity in petroleum from different areas (Schlumberger).

Petroleum Coke

A solid residue high in carbon content and low in hydrogen that is the final product of thermal decomposition in the condensation process in cracking. This product is reported as marketable coke or catalyst coke. The conversion is 5 barrels (of U.S. 42 gallons each) per short ton. Coke from petroleum has a heating value of 6.024 million Btu per barrel (EIA).

Pigging

A procedure of forcing a solid object through a pipeline for the purposes of displacing or separating fluids, and cleaning or inspecting the line (Schlumberger).

Piston Chemical Injection Pump (CIP)

There are two different types of piston CIPs. Both are a small positive displacement, reciprocating unit designed to inject precise amounts of chemicals into process streams. There are two different types. The barrel-type piston pump consists of a cylindrical piston-plunger assembly where the movement of the larger-diameter piston provides the force needed to move the plunger. Another type of piston pump observed at sites in California use a horizontal plunger to operate a gear mechanism that drives the plunger (Shires, 1996).

Pneumatic Device

A mechanical device operated by some type of compressed gas. In the oil and gas industry, many devices, especially for instruments and valves, are powered by natural gas (Shires and Harrison, 1996). They may also be powered by air pressure (EIA).

Point Sources

An emission category that includes releases to the atmosphere that occur through stacks, vents, ducts, tailpipes, or other confined streams.

Precision

A measure of the degree of random variability associated with a data value (Williamson, Hall, and Harrison, 1996).

Pressure Relief Device (or Pressure Relief Valve or Pressure Safety Valve)

A valve that opens at a preset pressure to relieve excessive pressures within a vessel or line; also called a relief valve, safety valve, or pop valve (API, 1988).

Process Gas

Any gas generated by an industrial process (e.g. petroleum refining).

Process Vents

A subcategory of point sources that produce emissions as a result of some form of chemical transformation or processing step.

Pump Seals

Any seal on a pump drive shaft used to keep methane and/ or carbon dioxide containing light liquids from escaping the inside of a pump case to the atmosphere.

Purge

The process of clearing air from equipment by displacing it with natural gas; in the process, some purge gas is emitted as the air is evacuated from the equipment (Shires, 1996).

Reciprocating Compressor

A piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the drive shaft (CAPP, 2004).

Reciprocating Compressor Rod Packing

A series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere (Hyne, 1991).

Reciprocating Engine

An engine that uses the up and down motion of pistons in a cylinder to drive a crankshaft (Hyne, 1991).

Refinery Fuel Gas (still gas)

Any form or mixture of gases produced in refineries by distillation, cracking, reforming, and other processes. The principal constituents are methane, ethane, ethylene, normal butane, butylene, propane, propylene, etc. Still gas is used as a refinery fuel and a petrochemical feedstock (EIA, 2008).

Regasification

The process by which LNG is heated, converting it into its gaseous state (LNG, 2006).

Reid Vapor Pressure (RVP)

A measure of the tendency of a liquid to vaporize. RVP is the pressure of the vapor portion of a liquid plus the enclosed air plus the water vapor under standard conditions, measured in pounds per square inch (psi) at 100°F (Hyne, 2006).

Renewable Energy

Energy taken from sources that are inexhaustible (e.g., wind, water, solar, geothermal, and biofuels) (IPIECA, 2003).

Residual Fuel Oils

A general classification for the heavier oils, known as No. 5 and No. 6 fuel oils, that remain after the distillate fuel oils and lighter hydrocarbons are distilled away in refinery operations. No. 5, a residual fuel oil of medium viscosity, is also known as Navy Special and is used in steam-powered vessels in government service and inshore power plants. No. 6 fuel oil includes Bunker C fuel oil and is used for the production of electric power, space heating, vessel bunkering, and various industrial purposes (EIA).

Source

Any physical unit or process that releases greenhouse gases into the atmosphere (IPIECA, 2003).

Sour Gas

A general term for those gases that are acidic either alone or when associated with water. See also acid gas (Schlumberger).

Standard Conditions

For the purpose of this document, standard conditions for converting gas flow rates between mass and volume bases are 14.7 psia and 60°F.

Stationary Combustion Sources

Stationary combustion sources include external combustion devices such as boilers and heaters, and internal combustion devices such as turbines and engines.

Steam Reforming

A catalytic process that produces hydrogen by splitting water. This involves a reaction between natural gas or other light hydrocarbons and steam. The result is a mixture of hydrogen, carbon monoxide, carbon dioxide, and water (Hydrocarbons-Technology, 2009).

Sulfur Recovery Unit

A process unit that recovers elemental sulfur from gases that contain reduced sulfur compounds and other pollutants, usually by a vapor-phase catalytic reaction of sulfur dioxide and hydrogen sulfide.

Ton

A short ton is equivalent to 2,000 US pounds.

Tonne

A metric tonne is equivalent to 1,000 kg and 2,204.62 US pounds. Metric tonnes are the standard convention for reporting greenhouse gas equivalent emissions used by IPCC and other international climate change organizations (Hyne, 1991; LNG, 2006).

Total Hydrocarbons (THC)

Used interchangeably with the term TOC in this document. THC sometimes refers to hydrocarbon compounds that are measured using a Flame Ionization Detector (FID) of a gas chromatograph (GC).

Total Organic Compound (TOC)

Includes VOCs, semi-volatile organic compounds, and condensable organic compounds. Emissions of VOCs are primarily characterized by the criteria pollutant class of unburned vapor phase hydrocarbons. Unburned hydrocarbon emissions can include essentially all vapor phase organic compounds emitted from a combustion source. These are primarily emissions of aliphatic, oxygenated, and low molecular weight aromatic compounds which exist in the vapor phase at flue gas temperatures. These emissions include all alkanes, alkenes, aldehydes, carboxylic acids, and substituted benzenes (e.g., benzene, toluene, xylene, and ethyl benzene). Used in AP-42 to indicate all VOCs and all exempted organic compounds including methane, ethane, chlorofluorocarbons, toxics and hazardous air pollutants, aldehydes, and semivolatile compounds (EPA, 1998(a)).

Turbine

A motor consisting of a rotating shaft with propellers or blades that are driven by a fluid (Hyne, 1991).

Uncertainty

The range around a reported value in which the true value can be expected to fall (IPIECA, 2003).

Unfinished Oils

All oils requiring further processing, except those requiring only mechanical blending. Unfinished oils are produced by partial refining of crude oil and include naphthas and lighter oils, kerosene and light gas oils, heavy gas oils, and residuum (EIA).

Upstream

Operations involving the exploration, development, and production of oil and gas. May also include gas processing (IPIECA, 2003).

Utility Boiler

Refers to the following Source Classification Codes (SCC) for Electric Generation units: 1-01-004-01/04/05/06 (distillate fuel fired units), 1-01-005-01/04/05 (residual fuel fired units), 1-01-006-01/02/04 (natural gas fired units), 1-01-010-01/02/03 (liquefied petroleum gas fired units), and 1-01-007-01/02/03/04/07/12 (process gas fired units). A previous edition (4th edition) of AP-42 defined a natural gas utility boiler as a boiler with a heat input capacity of greater than 100 MMBtu/hr (EPA, 1985 to 1993).

Vapor Recovery Unit

A system used to recover vapors formed inside completely sealed crude oil or condensate tanks (Schlumberger).

Volatile Organic Compound (VOC)

Any compound of carbon, excluding carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate, which participates in atmospheric photochemical reactions (40 CFR 51.100, June 23, 2009). Pollutants commonly classified as VOC encompass a wide spectrum of volatile organic compounds that are photochemically reactive in the atmosphere. Compounds deemed to have “negligible photochemical reactivity” and therefore excluded include acetone, methane, ethane, methylene chloride, methyl chloroform, perchloroethylene, methylated siloxanes, many chlorofluorocarbons, certain classes of perfluorocarbons and hydrofluorethers, and some fluorinated alkenes, ethers and amines.

Weathered Crude Oil

Crude oil which has reached atmospheric pressure and has had the volatile CH_4 flashed off.

Well Completion

A term used to describe the assembly of down hole tubulars and equipment required to enable safe and efficient production from an oil or gas well (Schlumberger).

Wet Natural Gas or Wet Gas

(1) A gas containing water, or a gas which has not been dehydrated. (2) A term synonymous with rich gas, i.e., a gas from which products have not been extracted (GPSA, 1987).

Workover

Operations on a producing well to restore or increase production. A workover may be done to wash out sand, acidize, hydraulically fracture, mechanically repair, or for other reasons (API, 1988).

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Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Natural Gas and Oil Industry

Appendix H – Acronyms and Abbreviations

November 2021

ACRONYMS AND ABBREVIATIONS

AAV	Ambient Air Vaporizer
AF	activity factor
AGA	American Gas Association
AGR	acid gas removal
API	American Petroleum Institute
AR4	Fourth Assessment Report
AR5	Fifth Assessment Report
ARPEL	Regional Association of Oil and Natural Gas Companies in Latin America and the Caribbean
ASTM	American Society of Testing and Materials
bbl	barrels
BOD	Biological Oxygen Demand
BOE	barrels of oil equivalent
BTU	British Thermal Units
ºC	Celsius
C	carbon
C_2H_6	ethane
C_3H_8	Propane
C_4H_{10}	n-Butane
C_5H_{12}	n-Pentane

C_6H_{14}	n-Hexane
C_7H_{16}	n-Heptane
C_8H_{18}	Octanes
$C_{11}H_{24}$	Undecane
CAC	Criteria Air Contaminant
CAPP	Canadian Association of Petroleum Producers
CARB	California Air Resource Board
CBM	coal bed methane
CCS	carbon capture and geological storage
CCU	catalytic cracking unit
CCUS	carbon capture utilization and storage
CEC	California Energy Commission
cf	cubic feet
CF	fraction of carbon
CFR	U.S. EPA Code of Federal Regulations
CH_4	methane
CHIEF	Clearinghouse for Inventories and Emission Factors
CHP	Combined Heat and Power
CIPs	chemical injection pumps
cm^3	cubic centimeter
CNG	compressed natural gas
CO	carbon monoxide
CO_2	carbon dioxide

CO_2e	carbon dioxide equivalents
COD	Chemical Oxygen Demand
CONCAWE	Conservation of Clean Air and Water in Europe
COP	coefficient of performance
Cp/Cv	gas specific heat ratio
CRR	catalyst regeneration rate
CRUs	catalytic reformer units
DEA	diethanol amine
Defra	Department for Environment, Food and Rural Affairs
DI&M	directed inspection and maintenance
DOE	U.S. Department of Energy
E&P	exploration and production
EAC	Energy Attribute Certificate
EF	emission factor
EEA	European Environment Agency
EIA	Energy Information Administration
EIIP	Emission Inventory Improvement Program
EMEP	European Monitoring and Evaluation Programme
EOR	enhanced oil recovery
EPA	Environmental Protection Agency
ESB	emergency blowdowns
ESD	emergency shutdowns
ETS	Emissions Trading Scheme

EU	European Union
EUB	Alberta Energy Utility Board
ºF	Fahrenheit
FCC	fluid catalytic cracking
FCCUs	fluid catalytic cracking units
FPSO	floating production storage and offloading
ft^3	cubic feet
gal	gallon
GCV	gross calorific value
GOR	gas-to-oil ratio
GPR	gas production rate
GPSA	Gas Processors Suppliers Association
GHG	greenhouse gas
GHGI	U.S. EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks
GHGRP	Greenhouse Gas Reporting Program
GOs	Guarantees of Origin
GRI	Gas Research Institute
GTI	Gas Technology Institute
GWP	global warming potential
H_2	hydrogen
H_2O	water
H_2S	hydrogen sulfide
HD	heavy duty

HF	hydro fracturing
HFCs	hydrofluorocarbons
HHV	higher heating value
HNO_3	nitric acid
Hp	horsepower
IC	internal combustion
IEA	International Energy Agency
IFC	International Flare Consortium
INGAA	Interstate Natural Gas Association of America
IOGP	International Association of Oil and Gas Producers
IPCC	Intergovernmental Panel on Climate Change
IPIECA	International Petroleum Industry Environmental Conservation Association
ISO	International Organization for Standardization
J	Joule
K	Kelvin
kg	kilogram
kPaa	Kilo-Pascals absolute
kV	kilovolt
kW	kilowatt
L	liter
lb	pound
lbm	pound mass
LCV	light commercial vehicle

LDAR	leak detection and repair
LDC	local distribution company
LHV	lower heating value
LNG	liquefied natural gas
m^3	cubic meters
M&R	meter and regulator
MMS	Minerals Management Service
MMscf	million standard cubic feet
MMT	million metric tones
MMTCE	million metric tones of carbon equivalent
MOVES	Motor Vehicle Emission Simulator
MPMS	Manual of Petroleum Measurement Standards
MW	molecular weight
N_2O	nitrous oxide
NCASI	National Council for Air and Stream Improvement
NCV	net calorific value
NERC	North American Electric Reliability Council
NGLs	natural gas liquids
NMVOC	non-methane volatile organic compounds
NSCR	non-selective catalytic reduction
ODSs	ozone-depleting substances
OGI	optical gas imaging
OGP	Association of Oil and Gas Producers

ORV	open rack vaporizer
PFCs	perfluorocarbons
PPAs	power purchase agreements
PRV	pressure relief valves
PSI	Pipeline Systems Incorporated
psia	pounds per square inch absolute
psig	pounds per square in gauge
QC	quick coupling
QR	quick release
ºR	Rankine
RECs	reduced emissions completions
REC	Renewable Energy Credit
RVP	Reid Vapor Pressure
SAR	Second Assessment Report
scf	standard cubic feet
scm	standard cubic meters
SF_6	sulfur hexafluoride
SI	International System of Units
SMR	steam methane reforming
SPE	Society of Petroleum Engineers
SRUs	Sulfur Recovery Units
STV	Shell & Tube Vaporizer
TAR	Third Assessment Report

TCR	The Climate Registry
TD	transmission distance
T-D	transmission-distribution
THC	total hydrocarbon
TOC	total organic compound
T&S	transmission and storage
UKOOA	UK Offshore Operators Association Limited
UNFCCC	United Nations Framework Convention on Climate
USC	U.S. customary units
USEPA	U.S. Environmental Protection Agency
V	volume
VBE	The Vasquez-Beggs Equation
VCU	vapor combustion units
VOC	volatile organic compounds
VR	vent rate
WRI/WBCSD	World Resources Institute/World Business Council for Sustainable Development

American
Petroleum
Institute

200 Massachusetts Avenue NW
Suite 1100
Washington, DC 20001-5571
USA
+1 202-682-8000
wwww.api.org

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