Technical Documentation for the *SMART Plus* Facility Template

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DISCLAIMER

While reasonable effort has been made to ensure the accuracy, reliability, and completeness of the information presented herein, this manual is made available without any representation as to its use in any particular situation and on the strict understanding that each reader accepts full liability for the application of its contents, regardless of any fault or negligence of Clearstone Engineering Ltd. or Tetra Tech, Inc.

Some calculations within this Tool may require the use of emission factors that are specific to the United States or Canada, which may not be applicable for all countries. Emissions vary greatly by country, and the application of United States- and/or Canada-specific emission factors may not provide the most accurate results. Where feasible, it is recommended to conduct a refined emissions inventory using an IPCC Tier 2 (country-specific) emission factor approach or an IPCC Tier 3 (bottom-up) approach. It is also encouraged to incorporate direct measurement data into inventory estimates when possible, reducing reliance on emission factors. This Tool allows the user to refine their emissions inventory as described above and discussed in detail herein.

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LIST OF ACRONYMS

API	-	American Petroleum Institute
CAC	-	Criteria Air Contaminants
CEPEI	-	Canadian Energy Partnership for Environmental Innovation
CO_2E	-	Carbon Dioxide Equivalent GHG Emissions
CRF	-	Common Reporting Format
EF	-	Emissions Factor
ESG	-	Environment, Social, and Governance
GFMR	-	Global Flaring and Methane Reduction Partnership
GHG	-	Greenhouse Gas
GMI	-	Global Methane Initiative
GMP	-	Global Methane Pledge
GWP	-	Global Warming Potential
IPCC	-	Intergovernmental Panel on Climate Change
ISO	-	International Standards Organization
LDAR	-	Leak Detection and Repair
LPG	-	Liquefied Petroleum Gas
MRV	-	Measurement, Reporting, and Verification
NGL	-	Natural Gas Liquid
NMVOC	-	None-methane Volatile Organic Compound(s)
OGMP	-	Oil & Gas Methane Partnership
SLCP	-	Short-lived Climate Pollutant
UNEP	-	United Nations Environment Programme
UNFCCC	-	United Nations Framework Convention on Climate Change
U.S. EPA	-	United States Environmental Protection Agency
ZRF	-	GGFR Partnership's Zero Routine Flaring by 2030 Initiative

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Variable	Definition	Units	Notes
B	Emissions contribution	Varies	Used as intermediary in Equation 9.1
C	Gas content	mol percent	Defined in the "Gas Compositions" section of the Setup-Facility Details worksheet for various GHGs across gas streams
D	Density	kg/m^3	
E	Emission factor	Varies	Emission factor units differ by source category but are normalized in final calculations using conversion factors as applicable
F	Amount of fuel combusted	tonnes/yr	
G	Amount of gas processed	E+06 m^3 gas processed/day	
H	Higher heating value	GJ/tonne	
K	Measured contribution	Varies	Defined by the user from a dropdown list of 9 available units
L	Liquid fuel mass percent	Mass percent	
M	Molecular weight	kg/mol	
N	Conversion factor	Varies	Normalize final emissions calculations to units of tonnes/yr
Q	Quantity	Varies	Defined by user input
R	Rate of carbon oxidation	Percent	
S	Solid fuel mass percent	Mass percent	
T	Time	Percent	User input values for operating, standby, and/or depressurized time is expressed as a percentage
V	Volume	m^3/kmol	Standard volume
W	Flare efficiency	Percent	
X	Count	N/A	Component or equipment count; value depends on user input;
Y	Flashing losses	m^3/day	Value taken from Setup-Flashing Losses worksheet calculation
Z	Emissions per category	N/A	Categories 1-20 correspond to user-defined input in the “Processes used at the Facility” section of the Setup-Facility Details tab

LIST OF EQUATIONS

1. INTRODUCTION

1.1: General Tool Overview

SMART Plus (Simplified Methane Assessment and Reporting Tool) is a greenhouse gas (GHG) emissions inventory estimation tool for the oil and gas sector. The Tool comprises two MS Excel templates – *SMART Plus* Facility templates and *SMART Plus* Tier 1/Tier 2 Reporting templates – as well as a companion database application in Microsoft Access, the *SMART Plus* Database. Both templates calculate emissions and visualize results for the purposes of evaluating emissions of methane (CH_4), carbon dioxide (CO_2), nitrous oxide (N_2O), and total CO_2-equivalent (CO_2E) greenhouse gas (GHG) emissions at the national or facility level for oil and natural gas systems, respectively. The two templates also have features for assessing emissions of selected criteria air contaminants (CACs), namely oxides of nitrogen (NO_x), carbon monoxide (CO), non-methane volatile organic compound (NMVOC), and oxides of sulfur (SO_2), where applicable.

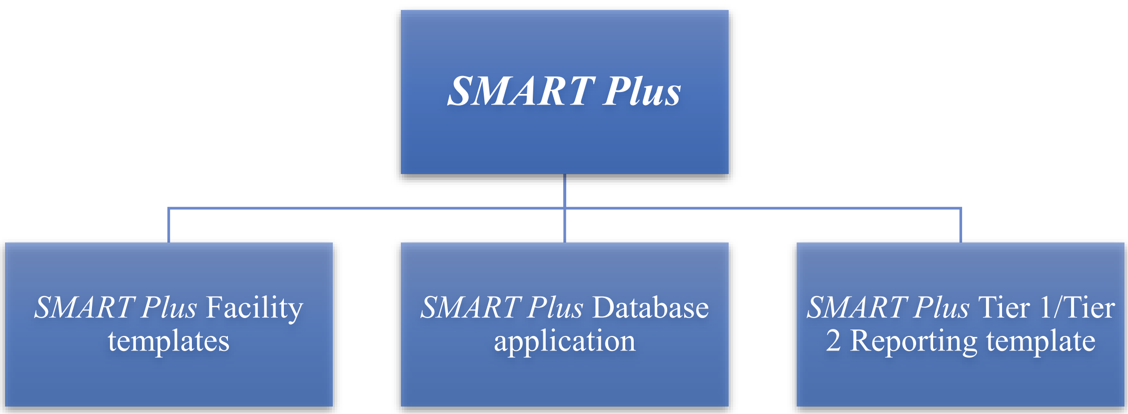

Figure 1: Components of *SMART Plus*

SMART Plus is user-friendly, enabling the assessments of GHG emissions from oil and gas facilities and systems from minimal user input information, and with the ability improve results as more refined activity and infrastructure data and actual measurement results become available. Both *SMART Plus* templates have been developed without the use of any macros to avoid potential issues with automated security checks, lockouts, and restrictions imposed by a user's computer system.

This document describes technical information and methodologies used by the *SMART Plus* Facility template only and does not provide the user a step-by-step guide to implementing all *SMART Plus* components. Similar documentation will be developed for other *SMART Plus* components, including the *SMART Plus* Database application and the *SMART Plus* Tier 1/Tier 2 Reporting template.

1.2: Overview of SMART Plus Tool components

The *SMART Plus* Facility template assesses the emissions for a single oil and gas facility or production accounting entity that can be defined in terms of a set of production accounting activity data (e.g., oil and gas throughput, fuel use, venting and flaring), and process infrastructure (i.e., the number and type of process units and major equipment, including wells where applicable). The types of emission sources considered include stationary combustion sources, process venting and flaring, fugitive equipment leaks, storage losses, inspection and maintenance activities, and indirect emission contributions due to electric power consumption. The emissions are estimated using published emission factors and user-defined input activity data. Where measured emissions data are available, this can be input and will override the estimation values. Site-specific gas analyses may also be input for improved emissions estimation and speciation. The source and facility classifications used by the *SMART Plus* Facility template and the administrative data it captures also align with that used by Level 3 of the Oil & Gas Methane Partnership 2.0 (OGMP 2.0) reporting and mitigation programme of the United Nations Environment Program (UNEP). Links are provided to U.S. EPA technical briefs on mitigation technologies that the user can consider for use in developing strategic site-specific emissions mitigation strategies.

A companion MS Access database application, the *SMART Plus* Database, has been developed for use with multiple populated *SMART Plus* Facility templates. The database application imports the results from multiple completed *SMART Plus* Facility templates, performs quality assurance checks while doing so, and aggregates and reports information by source type, region, operator, and industry segment. This is consistent with an IPCC Tier 3 (bottom-up) assessment for the given industry segments. The database application also calculates IPCC Tier 2 emission factors for a given source category defined by the user; see the *SMART* Plus Database application User Manual for more details. Depending on the user's circumstances, Tier 3 assessments can be conducted annually for one or more segments of a user's oil and gas systems, or periodically to determine Tier 2 emission factors for application in years between Tier 3 assessments.

The *SMART* Plus Tier 1/Tier 2 Reporting Template estimates fugitive and energy use emissions from oil and natural gas systems at the national level using the latest Tier 1 and Tier 2 procedures provided by the Intergovernmental Panel on Climate Change (IPCC) in the 2019 Refinements to the 2006 Guidelines for assessing national GHG emissions. This application observes the reporting structure defined by the common reporting format (CRF) used by parties to the United Nations Framework Convention on Climate Change (UNFCCC) when submitting their nationally determined GHG emission estimates to the UNFCCC. This template requires national statistics on the applicable portions of a user's oil and natural gas systems and applies the current IPCC Tier 1 emission factors as a default. Tier 2 emission factors can be entered where available and will override the Tier 1 calculations.

1.3: Documentation Overview

Section 2 of this manual provides a brief overview of oil and natural gas systems as well as background information on GHG inventories and mitigation. Section 3 delineates the key features of the *SMART Plus* Facility template. Section 4 contains a glossary of relevant oil and natural gas terminology. Section 5 lists all references cited in this document. Section 6 lists all appendices.

The appendices provide additional information on the equations, emission factors, and user-defined input options available in the *SMART Plus* Facility template.

2. BACKGROUND

This section provides background information on topics that are useful for those involved in the assessment and mitigation of GHG emissions to consider. This includes:

- Rationale for compiling and refining GHG inventories, and how *SMART Plus* helps users achieve these goals.
- Related GHG reporting and mitigation initiatives that may be useful to consider joining for potential access to technical support and to facilitate learning from like-minded and similarly circumstanced jurisdictions and operators.
- Potential terminology challenges to expect and access to definitions to help address these challenges.

2.1 Rationale for GHG Mitigation and Related Priority Objectives

Methane is a short-lived climate pollutant (SLCP) and a potent GHG with a global warming potential (GWP) of 27-30 times that of CO_2 on a 100-year time horizon. Reducing methane emissions is strategic for two key reasons. Firstly, it is a marketable commodity and reducing methane emissions is a good business practice. Secondly, reducing methane emissions has the potential to achieve significant cost-effective near-term reductions in climate forcing to help limit the global temperature rise to 1.5°C. In the oil and gas industry, methane emissions occur in all sectors including production, storage, processing, transmission, and distribution. Figure 2 shows various segments of the natural gas industry. The strategic pursuit of methane emission reductions can lead to positive local economic, social, environmental, and health benefits.

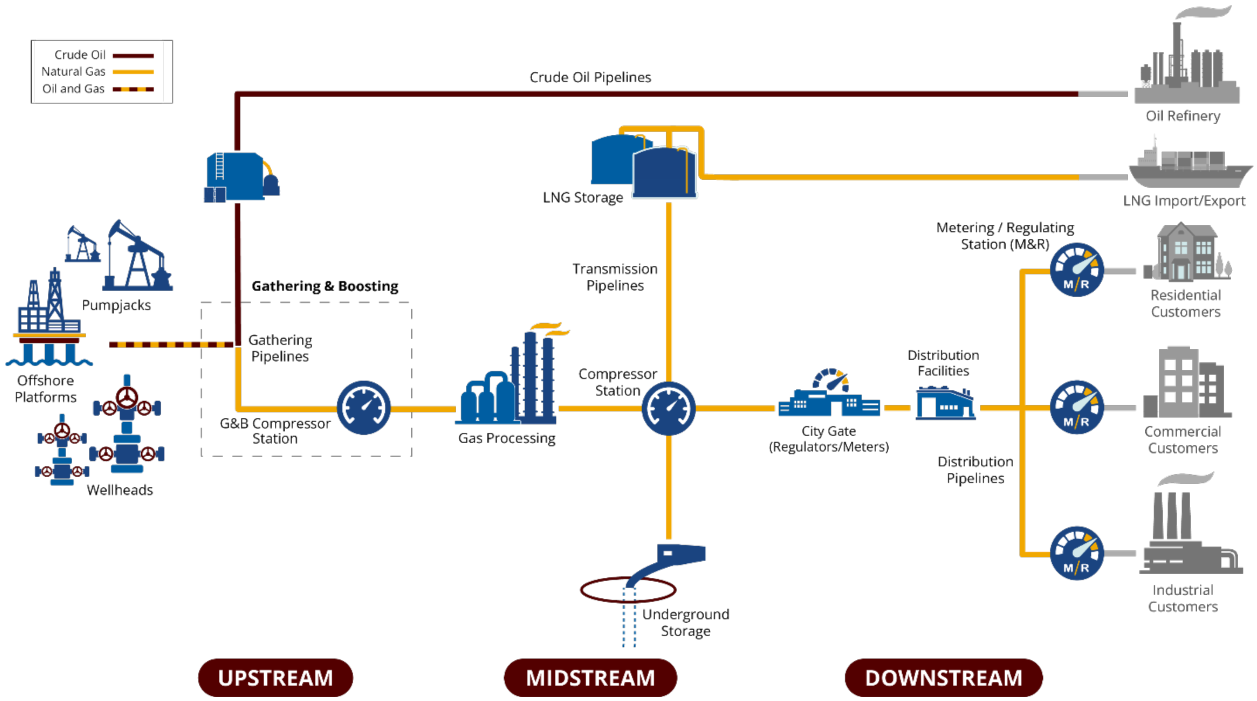

Figure 2: Diagram showing the different segments of a typical oil and natural gas system

Outputs of *SMART Plus* allow users to easily identify which values to include in their CRF reporting tables for the following IPCC categories:

CRF Category	Industry Segment
A.1	Energy Industries
A.1.b	Petroleum Refining
A.1.c	Manufacture of Solid Fuels and Other Energy Industries
B.2	Oil and Natural Gas
B.2.a	Oil
B.2.b	Natural Gas

Table 1: UNFCCC CRF category and corresponding industry segment

2.2 GHG inventories and SMART Plus

Accurate GHG inventories can help countries prioritize actions to reduce GHG emissions from oil and gas systems, and the completeness of an emissions baseline is key to developing robust and impactful climate policy. Further refining national GHG inventories (that is, progressing from an IPCC Tier 1 approach to a Tier 2 or Tier 3 approach) from oil and gas systems can provide a more thorough understanding of key emissions sources and aid in the design and implementation of mitigation efforts.

The various *SMART Plus* Tool components provide countries the opportunity to explore how the 2019 Refinement to the 2006 IPCC Guidelines impacts their national inventory submissions to the UNFCCC, as well as refine inventory estimates from previous years:

- The *SMART Plus* Facility template can also be used to conduct an initial desk review of potential emissions reduction opportunities at the facility level; however, the availability of measurement data for input to the application, and the completeness and accuracy of that information, will determine the effectiveness of such reviews. The practicability of addressing individual mitigation opportunities will depend on site-specific constraints including the potential to utilize conserved gas and the availability of economic market access.
- The *SMART Plus* Tier 1/Tier 2 Reporting template can be used to conduct a Tier 1 or Tier 2 assessment of GHG emissions at the national level. Default (Tier 1) emission factors from the 2019 Refinement to the 2006 IPCC Guidelines are automatically applied to user-input data to produce a Tier 1 emissions estimate. As country-specific (Tier 2) emission factors are developed, either through the capabilities of integrating *SMART Plus* Facility templates with the *SMART Plus* Database or generated from other field studies, assessments, etc., the user can input these emission factors when assessing their overall national-level GHG emissions from oil and gas, which will represent a refinement in their inventory compared to previous submissions. Any Tier 2 emission factors input by the user will override default Tier 1 emission factors built into the template.
- Multiple *SMART Plus* Facility templates, when used in conjunction with the *SMART Plus* Database, can be used to conduct a Tier 3 (bottom-up) assessment of GHG emissions, representing a further refinement of GHG emissions estimates. This pair of tool components could also be used to calculate a Tier 2 emission factor for a given emissions source category.

2.3 Intra-Industry and Jurisdictional Differences

The basic types of process equipment used to produce oil and natural gas are essentially the same worldwide (e.g., separators, heater treaters, compressors, gas sweetening units, glycol dehydrators, process heaters, storage tanks, etc.), and have not changed substantively in the last 60 or more years. Physical and operational differences could occur between countries, however, which could include the following:

- Design and operating practices.
- Type and extent of emissions controls being used.
- Quality of maintenance programs.
- Age of the infrastructure.
- Quality of components used.
- Level of regulatory enforcement.

- Types of production and reservoir-specific characteristics (e.g., concentration of impurities in the gas, gas-to-oil ratios, proximity of oil production facilities to natural gas markets, whether the gas is sweet or sour, etc.).
- Record-keeping and data availability.

A common challenge for those for those not familiar with the oil and natural gas systems is the industry-specific terminology that is used, and the fact this terminology can vary between industry segment and by jurisdiction. For example, in China there are both natural gas transmission and distribution pipeline systems, and while their purpose is recognized as being different, there is no technical term to distinguish between them, which can be a source of confusion. Accordingly, the glossary presented in Section 4 is provided to help address some of these terminology-related challenges.

3. OVERVIEW OF THE *Smart Plus* FACILITY TEMPLATE

The *SMART Plus* Facility template is used to assess the emissions from a single facility or system (e.g., a gas gathering system and its associated infrastructure or a production facility and its connected wells). A separate copy of this template should be completed for each facility or system where the user intends to estimate emissions. The combined results of multiple *SMART Plus* Facility templates will reflect the expected average emissions inventory for similar facilities or systems, assuming that the specified infrastructure and emission controls are performing as expected and that the input activity data is complete and accurate. To obtain the best results, and as resources and circumstances may allow, users can consider periodically conducting a supplemental measurement program at a subset of the facilities to identify key emission sources and measure emissions. These results can be used to help validate a developed emissions inventory and more accurately identify high-value emissions mitigation opportunities. Ideally, supplemental information such as recent satellite data, results of aerial or ground-based mobile monitoring surveys, the age of facility, and the intrinsic emissions potential of each facility based on its design features and activity levels should be considered in strategically selecting the sites to be surveyed. Additionally, the developed emissions inventory results from a facility-level assessment of multiple similarly defined facilities or systems can be used to determine Tier-2 emission factors for later use with *SMART Plus* Tier 1/Tier 2 Reporting template.

The input data compiled in the *SMART Plus* Facility template is the minimum information needed to drive the emission calculations. All user-adjustable fields in this worksheet are highlighted in yellow. Dropdown lists of options are provided for several input parameters throughout the template; the allowable values for these parameters will change according to the industry segment that has been selected. Limited reasonableness checks are performed programmatically on the numeric input values as they are entered. Error messages are given where invalid setup conditions are applied.

This template includes the following worksheets:

- **Language & User Guidance**: This worksheet is where the user selects their language preference for the application. The currently available options are English, Mandarin Chinese, and Spanish. Additionally, the following information is provided:
    - An introduction to the template.
    - Details on the navigation and color-coding rules.
    - Instructions for defining and setting up the emission calculations for a facility.
    - Details on the applied emissions assessment methodology.
- **Contents**: This worksheet presents a matrix that delineates the purpose of each worksheet and provides hyperlinks for the user to navigate between worksheets.
- **Setup – Facility Assessment**: This worksheet is where the user defines the type of facility to be assessed and enters input information needed to determine the amount of GHG and CAC emissions. The required input information is divided into the following sections:
    - **Facility Definition**: This section is where the user specifies the industry segment (e.g., oil and gas production, gas processing, gas transmission, gas storage or gas distribution), type of facility to be assessed (e.g., compressor station, gas plant, oil battery), and, where relevant, indicates the density of the hydrocarbon liquids produced (e.g., light, medium, heavy, or very heavy). These choices will determine the specific emission factors used for some source types, such as fugitive equipment leaks. This section is also the user enters key administrative data needed to uniquely identify the facility.
    - **Facility Activity Levels:** This section captures the relevant available production accounting data for the specified facility, such as:
        - Receipt volumes for gas, oil, condensate, and/or produced water,
        - Venting and flaring rates,
        - Acid gas flaring,
        - Fuel consumption (by type of fuel and, in the case of gaseous fuels, by type of stationary combustion source), and
        - Electric power and heat purchases.

      The applicability of each of these parameters will depend on the type of facility and its design, as well as the operator's production accounting practices. When entering these data, the user can choose the most convenient units of measure from the available drop-down menu options.
    - **Direct Measurement Emissions Results (Where Available)**: If any site-specific direct emissions measurements have been performed, these results may be entered in this section. If emission measurement results are entered in this section, those results will override the corresponding emission estimates for that source category based on user input in the "Processes Used at the Facility" section described below. If no emission measurement results are entered for a given source category in this

section, then this section can be left blank; the template then automatically estimates the applicable emission contributions for that source category based on user input in the "Processes Used at the Facility" section described below. The options available for user input of direct measurement emissions are:

- Emissions from detected leaks
- Emissions from compressor seals
- Emissions from pits and ponds
- Emissions from associated well sites
- Emissions from other associated offsite installations
- Venting by glycol dehydrators
- Venting by gas sweetening units
- Venting by pneumatic controllers
- Venting by pneumatic chemical injection pumps
- Venting by other sources
- Non-flashing losses from storage tanks
- Casinghead venting

If the user has performed rigorous process simulations or engineering calculations to determine the emissions from any of these categories instead of measurements, then those results may be entered here as well.

User input in this section will override calculated emission factor-based estimates for respective sources, encouraging users to prioritize measured data when possible.

- **Processes Used at the Facility**: In this section, the user will input information that will be carried forward in the template to estimate emissions in the absence of direct measurement data. This is where the types of processes and major equipment packages used at that specific facility (e.g., separator, compressor, dehydrator, etc.) and their respective quantity are declared. The available options to choose from are shown in Table D-1 and will depend on the information input by the user in the Facility Definition section. Up to 20 entries may be made. Any replicate entries are assumed to be valid. Additionally, the user may provide certain operational data and information concerning the pneumatic devices (i.e., type of supply gas and type of controller) used on each process unit and indicate the percentage time the unit is in operating, standby & pressurized, and depressurized mode. Error messages occur if invalid time values are entered. The schedule of equipment components associated with each process unit (i.e., their quantity by type and service), and the number of pneumatic devices is automatically determined by the template based on the process unit type.
- **Gas Compositions**: Here the user can enter the chemical composition for the primary gas streams at the facility or use the existing entries as a default until such information can be obtained. To simplify this task, the user only needs to enter the CH_4 content and the content of the main impurities (i.e., CO_2, N_2 and H_2S). The

template estimates the content of all other compounds as needed based on this information.

- **Setup – Fuel Use**: This worksheet is where the user defines the type of fuel use to be assessed and inputs the information needed to determine the amount of GHG and CAC emissions from the combustion of that fuel. The required input information is divided into the following sections:
    - **Facility-Level Fuel Use Setup:** This section allows the user to estimate emissions from fuel combustion at the facility level. Here, the user can input measured or reported emissions from various types of solid, liquid, and/or gaseous fuels and related units of measure. Providing input in this section will override any information added to the following section.
    - **Fuel Allocation by Source Type:** In this section, the user can input source-specific combustion emissions information for each of the following source categories:
        - Heaters & Boilers
        - Compressor Engines
        - Generator Engines

      The user can select the specific source type, quantity, and fuel type consumed, as well as optional information such as operating time.
- **Setup – Flashing Losses**: This worksheet is where the user defines the type flashing losses to be assessed and enters input information needed to determine the amount of GHG and CAC emissions. The required input information is divided into the following sections:
    - **Facility-Level Flash Gas Emissions Setup:** If the user's facility includes storage equipment such as tanks, they will fill out this section, providing information on receipts of crude oil and produced water
    - **Oil Storage System Setup:** In this section, the user can select the type of oil storage system, operating temperature and pressure, flash gas factor, and vent control devices.
    - **Produced Water Storage System Setup:** Similar to the oil storage system setup section, here, the user can select the type of produced water storage system, operating temperature and pressure, flash gas factor, and vent control devices.
- **Results (Graphical)**: Here the user can generate and print a pie-chart of the assessed emissions for a selected GHG or CAC summarized by primary source category (i.e., fuel combustion, acid gas flaring, flaring & venting, fugitive equipment leaks, well casing vents, pneumatic devices, process venting, inspection & maintenance activities, mishaps, and indirect emissions from power and heat purchases) for the defined facility. Hyperlinks to relevant emissions mitigation technologies are also presented.
    - ***Note**: The largest wedges of the pie chart do not necessarily offer the greatest or most viable opportunities for emissions mitigation. The most promising high-value mitigation opportunities need to be assessed based on the control efficiency and practicability of the available mitigation technologies (i.e., considering factors such

as production decline rates, project life, market access, commodity pricing, and capital and operating costs), relevant site-specific constraints, and the emissions quantity (or scale of the opportunity).

- **Results (Tabular)**: This worksheet presents similar information to "Results (Graphical)" but in a tabular form, providing a more refined primary source category breakdown that, for example, considers the type of stationary combustion device and the type of pneumatic device. The global warming potentials used to assess the total CO_2E emissions are shown at the bottom of the table.

Other worksheets exist in the *SMART Plus* Facility template*;* however, these are hidden and password protected to avoid being corrupted and to simplify the template interface for the user. The following information is contained in these worksheets:

- **Detailed Results Tabulation:** This worksheet summarizes emissions calculations results by source category and pollutant type for the purposes of performing quality assurance checks. No calculations are performed on this worksheet.
- **Calculations**: All primary emissions calculations are performed programmatically on these worksheets based on user input carried forward from other worksheets in *SMART Plus - Facility*. The primary purpose of this worksheet is to provide transparency on how the calculations are performed and what information is used in the calculations.
  The calculations generally apply an EF equation in the following form:

$$ER_{CH4} = Activity \times EF_{CH4}$$

Where,

ER_{CH4}	=	Emission rate of CH_4 (m^3 CH_4/h)
Activity	=	Activity value for a given type of activity (e.g., number of equipment components of a particular type, number and type pneumatic device).
EF_{CH4}	=	CH_4 emission rate per unit of activity.

Similar equations are applied for CO_2, N_2O, CO, NO_x, NMVOC, and SO_2..

The primary calculation categories are as follows:

- Combustion emissions
  - Solid fuels
  - Liquid Fuels
  - Gaseous fuels

        - Hydrocarbon gas venting
        - Hydrocarbon gas flaring
        - Acid gas venting
        - Acid gas flaring
        - Electric power purchases
    - Fugitive and venting emissions
        - Equipment leaks
        - Compressor seals
        - Pneumatic controllers
        - Pneumatic chemical injection pumps
        - Pressure vessels (including blowdowns, workovers, completions, etc)
        - Compressor starts
        - Dehydrators
        - Gas sweetening units
        - Storage losses
        - Mishaps (i.e., accidental releases)
        - Well casinghead equipment

  There are no user-adjustable fields in these worksheets. See Appendix A for equations.

- **EFs – Equipment Leaks**: This worksheet includes average emission factors for estimating contributions from fugitive equipment leaks based on the leak/no-leak emission factor technique described in Appendix B, and the results are adjusted to reflect the penetration of emissions-reducing equipment modifications where applicable. This method requires information on the leak frequency for each component category. Company- or country-specific leak frequencies may be input in Column P in the cells highlighted in yellow. The type of equipment component modification may be entered in Column Q by selecting valid options from drop-down menu lists, and the percentage penetration of the modifications for a given component category may be entered in Column R in the yellow highlighted cells. No other cells in this worksheet are user adjustable. Table B-1 in Appendix B shows the types of equipment the Facility template evaluates for leaks.

  The leak/no-leak emissions factors presented for the upstream oil and natural gas production and processing sector are taken from U.S. EPA (1995). EPA-published leak/no-leak emission factors were not available for the Gas Transmission and Storage sector or for the Gas Distribution sector; therefore, values published by CEPEI (2016) were used for these sectors. The general theory is that an equipment component, when it leaks, will leak on average at a certain rate, and when it does not meet the leak definition (e.g., a 10,000-ppm hydrocarbon screening value measurement in accordance with EPA Method 21), it will still have some emissions that are characterized by the no-leak emission factor. The leak/no-leak emission factors vary by type of component and by industry sector. The differences in average emission factors between companies, or even countries, are caused more by differences in leak frequencies and component modifications than by material differences in leak/no-leak emission factors.

- **EFs – Other**: This worksheet presents a tabulation of EFs (U.S. EPA, 2014 and API, 2021) for application to the primary calculation categories included in the **Calculations** tab. The referenced factors are all presented in their original units of measure, and conversion factors are applied to convert the factors to units of m^3/d/device or source. The actual emission factor values may be replaced with company- or country-specific values; however, wherever this is done, the data source, the units of measure, and the conversion factors will all need to be updated accordingly. See Appendix C, Tables C-1 through C-9.
- **Equipment Schedules**: More than 20 typical quantity and types of equipment components, pneumatic devices, and process vessels associated with each type of process unit (see Appendix D, Table D-1) are defined on this worksheet by industry sector. The data have been drawn from CAPP (2005), CEPEI (2016), and API (2021) or estimated based on engineering judgement in the absence of any published values. These values may be changed to reflect company- or country-specific information.
- **Constants**: This worksheet lists all constants used in the *SMART Plus* Facility template. These include parameters such as molecular weights of CH_4 and CO_2 and standard temperature and pressure. There are no user-adjustable fields in this worksheet. See Appendix E, Tables E-1 Through E-6.
- **Look-Up Tables**: This worksheet tabulates all the look-up lists used in the pulldown menus programmed into user adjustable data input fields. These tabulations include the conversion factor look-up table, leak control factor look-up table, and the facility-type look-up table. There are no user-adjustable fields in this worksheet. See Appendix F, Tables F-1 through F-15.
- **Look-Up Lists**: This worksheet presents all look-up lists used in the pulldown menus programmed into the user adjustable data input fields. These lists include type of industry segment, dehydrators, pneumatic supply gas, hydrocarbon liquids, and controllers. There are no user-adjustable fields in this worksheet. See Appendix F, Table F-16.
- **Utilities - Venting Calculation**: This worksheet presents selected useful calculations that have been programmed into the template to enable users to estimate certain emissions volumes. These calculations include the volume of gas released by blowdown and purging events, and the amount of gas consumption by pneumatic chemical injection pumps. <u>The results of such calculations are not automatically carried forward into any of the other worksheets</u>. Any of the results from the calculations performed in this worksheet must be manually carried forward to other worksheets (e.g., to update emission factors). All input fields on this worksheet are highlighted in yellow. Appendix G presents details of the implemented calculations.
- **Utilities – Gas Properties:** This worksheet provides user input cells for known gas composition values. These values are then used to calculate various properties of the specified gas stream. These properties are carried forward in the Calculations worksheet.

- **Compressibility Factors** – This worksheet presents a tabulation of compressibility factors presented as a function of the type of natural gas, pressure, and temperature. These values are primarily for use in the utility calculations. Users must look up the compressibility factors most applicable to their circumstances and manually enter the information into the applicable calculations in the "Utilities – Venting Calculation" worksheet. The presented compressibility factors are not used anywhere else in the template. There are no user-adjustable fields in this worksheet. See Appendix G.
- **Translation Table**: This worksheet contains translations for Spanish and Mandarin Chinese, which will be reflected in the template if the user selects one of these languages from the "Language and User Guidance" tab.

4. GLOSSARY

Term	Definition
Abandoned Well	A well that has been drilled, abandoned, cut, and capped at surface.
Abandonment	The permanent dismantlement of a facility so that it is permanently incapable of its original intended use. This includes leaving downhole or subsurface structures in a permanently safe and stable condition; the removal of associated equipment and structures; the removal of all produced liquids; and the removal and appropriate disposal of structural concrete.
Accidental Releases	Unintentional releases of oil, produced water, process chemicals and/or natural gas to the environment by human error, equipment malfunction, or a major equipment failure (e.g., pipeline break, well blow out, explosion, etc.).

Term	Definition
Acid Gas	A gaseous mixture that is separated in the treating of solution or non-associated natural gas and which typically contains hydrogen sulfide (H_2S), total reduced sulfur compounds, and/or carbon dioxide (CO_2).
Acid Gas Injection Facility	Facility constructed and operated for the purpose of moving acid gas (a mixture containing (H_2S, total reduced sulfur compounds, and/or CO_2 that is separated in the treating of solution or non-associated natural gas) into a petroleum reservoir or other porous and permeable geologic formation.
Ancillary Equipment	Any of the following pieces of equipment: pumps, pressure relief devices, sampling connection systems, open-ended valves, or lines, valves, flanges, or other connectors.
API Gravity	The weight per unit volume of hydrocarbon liquids as measured by a system recommended by the American Petroleum Institute (API). The measuring scale is calibrated in terms of degrees API. API Gravity is the industry standard for expressing the specific gravity of crude oils. A high API gravity means lower specific gravity and lighter oils.
Associated Natural Gas	Natural gas that is produced in conjunction with crude oil, including bitumen.
Bitumen	A naturally occurring viscous mixture consisting of hydrocarbons heavier than pentane and other contaminants, such as Sulphur compounds, which in its natural state will not flow under reservoir conditions or on the surface. Bitumen occupies the lower end of the range of heavy crude oils and is sometimes referred to as ultra-heavy crude oil.
Black Oil	A hydrocarbon (petroleum) liquid with an initial producing gas-to-oil ratio (GOR) less than 0.31 cubic meters per liter and an API gravity less than 40 degrees.
Blanket Gas	Storage tanks are equipped with gas blanket systems to reduce vapor emissions (especially when the vapors are sour) and to ensure that oxygen does not enter the vapor space of the tank when it is connected to a flare system or vapor recovery unit. The blanket gas is usually fuel gas, but any other inert gas could be used. Storage tanks with gas blanket systems are usually connected to a flare or vapor recovery system, but in some cases (if the gas is not sour) the tank vapors and blanket gas may be released untreated to the atmosphere through a vent system.
Block Valve Station	A block valve used to isolate a segment of the main pipeline for tie-in or maintenance purposes. On gas transmission systems, block valves are typically located at distances of 25 to 80 km along each line to limit the amount of piping that may need to be depressurized for tie-ins and maintenance, and to reduce the amount of gas that would be lost in the event of a line break.

Term	Definition
Blowdown Treatments	Some natural gas wells must be blown down periodically to remove water that has accumulated in the production tubing. These are primarily shallow (less than 1000 m deep), low-pressure (less than 2000 kPa) gas wells. Shallow gas wells are typically sweet and usually are not equipped with flares. Thus, the natural gas that is discharged during blowdown operations is vented to the atmosphere unburned.
Blowout	The complete loss of control of the flow of fluids from a well to the atmosphere or the flow of fluids from one underground reservoir to another (an underground blowout). Wellbore fluids are released uncontrolled at or near the wellbore. Well control can only be regained by installing or replacing equipment to shut in or kill the well or by drilling a relief well.
Boiler	An enclosed device using controlled flame combustion and having the primary purpose of recovering and exporting thermal energy in the form of steam or hot water.
Booster Station	A facility where gas pressure is increased to overcome friction losses through a pipeline. Centrifugal or axial-flow compressors are commonly used in these applications. A station typically comprises several units in series or parallel, as well as the necessary suction and discharge piping. Many booster stations also have discharge coolers to reduce the viscosity of the compressed gas and thereby increase the efficiency of gas transmission.
Border Meter Station	A meter station where custody of the natural gas is transferred from one gas transmission system to another at a provincial or national boundary. These stations are usually larger than normal meter stations. Typically, they have 10 to 20 large diameter meter runs (16 to 20 NPS lines) and no pressure regulation.
Casinghead Gas	Dissolved natural gas and associated natural gas may be produced concurrently from the same well bore. In such situations, it is not feasible to measure the production of dissolved gas and associated gas separately; therefore, production is reported as casinghead gas. Sometimes it may simply be referred to as either associated gas or solution gas.
Central Crude Oil Treating Plant	Battery system or arrangements of tanks or other surface equipment without any directly associated wells.
Centrifugal Compressor Seal Systems	Centrifugal compressors generally require shaft-end seals between the compressor and bearing housings. Either face-contact oil-lubricated mechanical seals or oil-ring shaft seals, or dry-gas shaft seals are used. The amount of leakage from a given seal will tend to increase with wear between the seal and compressor shaft, operating pressure, and rotational speed of the shaft.
Closed-Vent System	A system that is not open to the atmosphere and is composed of piping, ductwork, connections, and if necessary, flow inducing devices that transport gas or vapor from an emission point to one or more control devices.
Cold Recovery	The production of crude oil which does not involve the use of any thermal techniques.

Term	Definition
Combustion Device	An individual unit of equipment, such as a flare, incinerator, process heater, or boiler, used for the combustion of organic emissions.
Combustion Efficiency	The extent to which all input combustible material has been completely oxidized (i.e., to produce H_2O, CO_2 and SO_2). Complete combustion is often approached but is never actually achieved. The main factors that contribute to incomplete combustion include thermodynamic, kinetic, mass transfer and heat transfer limitations. In fuel-rich systems, oxygen deficiency is also a factor.
Commercial Meter Set	Customer metering facilities for gas sales to a commercial customer. They include both pressure regulation and measurement. The regulator reduces the pressure from distribution pressure to 1.7 kPag (0.25 psig) or often a higher pressure, typically not more than 140 kPag (20 psig).
Compressed Natural Gas (CNG)	Natural gas compressed into high-pressure fuel cylinders to power a car or truck. It comes from special CNG fuel stations.
Compressor Start Gas	Most gas-fired compressors use a gas-operated motor for starting. Typically, the supply gas is natural gas but, in some cases compressed air may be used. During a start the gas passes through the start motor and is vented to the atmosphere. Start volumes are rarely measured and are most often estimated based on the number of starts and their duration or simply the number of starts.
Compressor Station	A facility where gas pressure is increased to allow the gas to enter a higher-pressure pipeline system (i.e., feed rather than booster service). Both centrifugal and reciprocating compressor units may be used in these applications. However, use of reciprocating compressors is most common. A station typically comprises several units in series or parallel, as well as the necessary suction and discharge piping. Many compressors also have discharge coolers to reduce the viscosity of the compressed gas and thereby increase the efficiency of gas transmission.
Condensate	Hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, that remains liquid at standard reference conditions.
Connectors	Any flanged or threaded connection, or mechanical coupling, but excluding all welded or back-welded connections. If properly installed and maintained, a connector can provide essentially leak-free service for extended periods of time. However, there are many factors that can cause leakage problems to arise. Some of the common causes include vibration, thermal stress and cycles, dirty or damaged contact surfaces, incorrect sealing material, improper tightening, misalignment, and external abuse.
Control Device	Any equipment used for recovering or oxidizing waste natural gas or VOC vapors. Such equipment includes, but is not limited to, absorbers, carbon adsorbers, condensers, incinerators, flares, boilers, and process heaters.
Control Valve Station	A modulating valve that controls either the flow rate or pressure through the pipeline. In the latter case, this facility is often referred to as a regulator station.

Term	Definition
	Usually, high-pressure gas from the pipeline is used as the supply medium needed to energize the valve actuator.
Conventional Crude Oil	Crude oil obtained via “conventional” recovery methods (i.e., normal primary, secondary, or tertiary processes) from a “conventional” source (i.e., not from bituminous sands, shales or carbonates) in a “conventional” location (i.e., not from the frontier, including the offshore).
Conventional Natural Gas	Natural gas obtained via “conventional” recovery methods (i.e., normal primary, secondary, or tertiary processes) from a “conventional” source (i.e., not from coalbeds or tight reservoir formations) in a “conventional” location (i.e., not from the frontier, including the offshore).
Crude Bitumen	A term used by the Government of Alberta to designate any non-coal, non-natural gas hydrocarbon produced from a designated oil sands area.
Crude Oil	A mixture of hydrocarbons that exist in the liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure and temperature after passing through surface separation facilities.
Crude Oil Battery	A system or arrangement of tanks or other surface equipment receiving primarily oil or bitumen from one or more wells prior to delivery to market or other disposition. An oil battery may include equipment for measurement, for separating inlet streams into oil, gas, and/or water phases, for cleaning and treating the oil, for disposal of the water, and for conservation of the produced gas. A tank battery may or may not include a glycol dehydration unit and compressor.
Crude Oil Group Battery	Crude oil production facility consisting of two or more flow-lined oil wells having individual separation and measurement equipment but with all equipment sharing a common surface location.
Crude Oil Losses	The volume of crude oil (including lease condensate) reported by petroleum refineries, pipelines, and lease holders as being lost or unaccounted for in their operations. These losses are of a non-processing nature (i.e., losses due to spills, contamination, fires, etc.), as opposed to refinery processing losses or gains.
Crude Oil Proration (or Field gate) Battery	A production facility consisting of two or more flow-lined oil wells having common separation and measuring equipment. Total production is prorated to each well based on individual well tests. Individual well production tests can occur at the central site or at remote satellite facilities.
Crude Oil Satellite Battery	A small group of surface equipment (not including storage tanks) located between a number of wells and the main crude oil battery that is intended to separate and measure the production from each well, after which the fluids are recombined and piped to the main crude oil battery for treating and storage or delivery.
Crude Oil Single Battery	Crude oil production facility for a single oil well or a single zone of a multiple completion crude oil well.

Term	Definition
Custody Transfer Point	The transfer of hydrocarbon liquids or natural gas: after processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.
Custom Treating Plant	System or arrangement of tanks and other surface equipment receiving crude oil/water emulsion exclusively by truck for separation prior to delivery to market or other disposition.
Cyclical Well	A crude bitumen well requiring steam to be injected to produce the hydrocarbons. The steaming and producing are performed in alternating cycles.
Deep Natural Gas Well	A gas well greater than 1000 m deep. These wells are typically high pressure and may be sweet or sour.
Dehydrator	A device used to remove water and water vapors from gas. Gas dehydration can be accomplished through a glycol dehydrator or a dry-bed dehydrator, which use a liquid desiccant and a solid desiccant, respectively.
Destruction Efficiency	The extent to which a target substance present in the input combustibles has been destroyed (i.e., converted to intermediate, partially oxidized and fully oxidized products of combustion).
Development Well	A well drilled within the proven area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive. If the well is completed for production, it is classified as an oil or gas development well. If the well is not completed for production, it is classified as a dry development hole.
Diesel Fuel	A general term covering light fuel oil derived from gas oil used in diesel engines.
Direct-Fired Heater	The combustion gases occupy most of the heater volume and heat the process stream contained in pipes arranged in front of refractory walls (the radiant section) and in a bundle in the upper portion (the convective section). Convective heaters are a special application in which there is only a convective section.
Disposal Well	A well that is used for the disposal of any oilfield or processing waste fluids or produced water into a reservoir or aquifer.
Dissolved Natural Gas	Natural gas that is in solution with crude oil in the reservoir at reservoir conditions (temperature and pressure).
Distribution Farm Tap	A small pressure regulating station located in rural or semi-rural areas on high-pressure pipelines flowing odorized gas. It usually only regulates the pressure down to a distribution pressure, and often does not include metering equipment.
Distribution Mains	Distribution mains deliver odorized gas to the customers. They range in size from ¾" NPS in rural distribution to 24 NPS, with the most common being 2 to 8 NPS. Systems constructed of plastic pipe (mostly polyethylene, but also P.V.C. or some other plastics), typically, are operated at pressures of up to 690 kPag (100 psig), although there are polyethylene resins that allow operation at pressures slightly

Term	Definition
	over 700 kPag (100 psig). Higher pressure steel pipelines (either with or without cathodic protection) flowing odorized gas are considered distribution mains in this document. A few older systems constructed of cast iron also exist. For calculating methane emissions from distribution mains, all small associated facilities, such as isolation valves, are part of the main.
Distribution Stations	Stations associated with the distribution mains that handle odorized natural gas. By function they include gate stations, district regulating stations, distribution farm taps and industrial meter sets.
District Regulating Stations	A secondary regulating facility located downstream of a gate station on gas distribution systems where gas pressure is further reduced (usually to about 400 kPag [60 psig] but sometimes only to 1200 kPag [175 psig], depending on the company).
Dry Hole	An exploratory or development well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.
Dry Natural Gas	Field natural gas that does not require any processing to meet contract hydrocarbon dew point requirements.
Emergency Shutdown (ESD) Valve Station	A valve installed on a pipeline, which will automatically close when the line pressure drops below critical a predetermined value. The purpose is to minimize the amount of gas released in the event of a line break. ESD valve stations are most used on sour natural gas gathering systems.
Emulsion	A combination of two immiscible liquids, that is, liquids that do not mix under normal conditions.
Emulsion Treater	See heater-treater.
Enhanced Recovery	The production of crude oil using secondary and/or tertiary recovery techniques.
Equipment Leaks	Emissions of natural gas or hydrocarbon liquids from equipment components (i.e., valves, connectors, compressor seals, pump seals, pressure relief devices, and sampling systems).
Extraction Loss (or Shrinkage)	The reduction in volume of natural gas resulting from the removal of the natural gas liquid constituents of natural gas at the processing plant.
Extra Heavy Crude Oil	A category of crude oil characterized as having a high viscosity, carbon-to-hydrogen ratio, and density - typically greater than 1000 kg/m^3 (i.e., less than 10.0° API).
Farm Well	A well that is used to supply hydrocarbons or water to a farm for utility purposes.
Field	An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated

Term	Definition
	vertically by intervening impervious strata, or laterally by local geologic barriers, or by both.
Field Dehydrator	A dehydration unit located upstream of a natural gas processing plant or natural gas battery to control hydrates rather than provide any final treatment to meet sales specifications.
Field Facility	An installation designed for one or more specific limited functions. Such facilities usually process natural gas produced from more than one lease for the purpose of recovering condensate from the stream of natural gas; however, some field facilities are designed to recover propane, butane, natural gasoline, etc., and to control the quality of the natural gas to be marketed. Field facilities include compressors, dehydration units, field extraction units, scrubbers, drip points, conventional single or multiple stage separation units, low temperature separators, and other types of separation and recovery equipment.
Field Natural Gas	Natural gas extracted from a production well prior to it entering the first stage of processing, such as dehydration.
Filling Losses	Evaporation losses that occur during the filling of tank trucks, tanker rail cars and marine tankers.
Fire-Tube Heaters	The combustion gases are contained in a fire-tube that is surrounded by a liquid that fills the heater shell. This liquid may be either the process stream or a heat medium that surrounds the coil bundle containing the process stream. Common applications are indirect-fired water-bath heaters (line heaters) and glycol reboiler.
Fixed Roof	A cover that is mounted on a storage vessel in a stationary manner and that does not move with fluctuations in liquid level.
Flare	An open flame used for routine or emergency disposal of waste gas. There are a variety of different types of flares including: flare pits, flare stacks, enclosed flares and ground flares.
Flared	Flaring is a common method of disposing of waste gas volumes at oil and gas facilities. The flare stacks are designed to provide safe atmospheric dispersion of the effluent. Flares are normally used where the waste gas contains odorous or toxic components (e.g., hydrogen sulfide). Otherwise, the gas may be vented. Typically, separate flare/vent systems are used for high- and low-pressure waste gas streams.
Flow Indicator	A device that indicates whether gas flow is present in a line or whether the valve position would allow gas flow to be present in a line.
Flowing Well	A well capable of producing fluids to surface through natural reservoir drive mechanisms, usually formation pressure.

Term	Definition
Formation CO_2 Releases	The atmospheric release of naturally or artificially occurring CO_2 originally present in the produced crude oil and natural gas. Formation CO_2 is most often extracted in the gas sweetening process.
Fuel Combustion	This accounts for the emissions from the consumption of all types of fuel typically encountered at oil and gas facilities (i.e., natural gas, propane and diesel) in both internal (reciprocating engines and gas turbines) and external (heater and boilers) combustion devices. Typically, emissions are estimated based on measured fuel volumes and published combustion emission factors.
Fugitive Emissions	The term "fugitive emissions" is very ambiguous. Typically, it is interpreted to mean unintentional releases, and often is thought to mean only equipment leaks. However, IPCC applies a much broader definition which basically classifies all sources of emissions in the energy sector into two categories: those from fuel combustion for the purpose of producing useful energy (e.g., heat or mechanical energy) and those from everything else (e.g., venting, flaring, incineration, equipment leaks, storage and handling losses, inspection and maintenance activities, purging activities, spills and accidental releases), with this latter category being referred to as fugitive emissions. The IPCC definition is applied here.
Fugitive Equipment Leaks	Fugitive equipment leaks are the loss of process fluid to the environment past a seal, connector (threaded or mechanical), cover, valve seat, flaw or minor damage point. In most cases these losses are unintentional and occur due to factors such as normal wear and tear, improper assembly or use, manufacturing defects, damage during installation, inspection or maintenance, corrosion, fouling during use and environmental effects (e.g., vibrations and thermal cycling). However, in some cases, such as certain pump and compressor seals, these components may be designed to leak a certain amount to continuously remove heat and debris away from the moving contact surfaces. In principle, none of the listed sources are 100 percent reliable or can be guaranteed to never leak. In practice, most equipment components do not have any measurable leakage, and most of those that do, contribute very little. Most of the emissions from fugitive equipment leaks tend to be contributed by only a few components at each site. Collectively, fugitive equipment leaks are a large, if not the largest, contributor of organic emissions at most types of facilities in the oil, gas, petroleum refining and petrochemical industries. Some of the potential reasons routine inspection and maintenance programs may not adequately control fugitive equipment leaks are as follows: • Beyond pressure tests and rudimentary leak checks that may be done when equipment is first put into service, normal inspection and maintenance programs tend to rely on visual, audible, and olfactory indicators as an ongoing means of leak detection thereafter, and then usually only focus on sources that are conveniently assessable. Thus, leaks get missed because they are out of normal

Term	Definition
	sight, are elevated and don't produce odors at ground level until the plume drifts some distance downwind, occur in noisy areas, or some combination thereof. • Workers become desensitized to smells and other sensory indicators of leaks. • Few companies apply predictive maintenance techniques. A reactive, rather than a proactive, approach is usually taken. • Leak detection and repairs do not receive high priority and workers are not given adequate time and tools to perform a proper job. • Corporate management systems and employee incentive programs normally do not quantify the benefits of leak control and the value of reduced or avoided emission. Consequently, the typical emphasis of companies on increasing revenues and production while minimizing maintenance and operating costs discourages the expenditure of time and resources on leak control and emission reduction measures. The need for maintenance generally increases as the equipment ages, but as the remaining anticipated life of a facility decreases, companies become reluctant to sustain the necessary level of maintenance investment. A formal leak detection and repair (LDAR) program comprises the systematic inspection of equipment specifically for leaks using U.S. EPA Method 21 (or equivalent technique) at regular intervals of once annually, or more frequently, if needed to maintain leak frequencies below maximum allowable limits. Formal LDAR programs involve the application of objective leak definitions (e.g., 10,000 ppm screening value), rules regarding the scheduling of repairs, use of database applications to manage survey results and track performance over time, and the use of survey results to guide material, component, and maintenance specifications in efforts for continuous improvement. Typically, formal leak detection and repair programs are either a regulatory requirement or a condition of the operating approvals at chemical plants and petroleum refineries. Most oil sands facilities and upgraders perform regular LDAR programs.
Gas Distribution	The delivery of natural gas from high-pressure transmission systems to customers.
Gas Distribution Network	The network or piping and other transportation equipment used to deliver natural gas to customers.
Gas Fractionation	A gas fractionation system is a cryogenic process for separating natural gas and refinery/upgrader off-gases into its constituent fractions to recover C2+ (ethane+) or C3+ (propane+) hydrocarbons.
Gas Lift Well	A well producing fluids into the tubing/annulus with the assistance of injected gas alone or in conjunction with mechanical equipment.

Term	Definition
Gas Market	Total end-user (i.e., industrial, commercial, and residential) natural gas demand.
Gas Oil	A medium distillate oil from the hydro processing unit at refineries and upgraders, which is used to produce diesel fuel. Sub-categories are vacuum gas oil (VGO) and straight-run gas oil.
Gas Plant - Acid Gas Flaring	A gas processing plant in which the acid gas (CO_2 and H_2S) extracted from the raw inlet gas contains sufficiently small quantities of sulfur that it can meet provincial sulfur emission and air quality requirements by simply flaring the acid gas. Supplemental fuel is typically required to ensure stable operation of the acid gas flare.
Gas Plant - Acid Gas Injection	A gas processing plant in which the acid gas (CO_2 and H_2S) extracted from the raw inlet gas is injected underground into an appropriate reservoir.
Gas Plant - Sulphur Recovery	A gas processing plant in which elemental sulfur is extracted from the acid gas (CO_2 and H_2S) prior to incineration.
Gas Plant - Sweet	A gas processing plant which processes natural gas containing less than 0.01 mol/kmol of H_2S.
Gas Plant Condensate	A natural gas processing plant product, mostly pentanes and heavier, recovered and separated as liquids at the gas inlet separators or scrubbers in natural gas processing plants or field facilities.
Gas Production	Total natural gas output from oil and gas wells.
Gas Sweetening	A process used to remove H_2S and CO_2 from a gas stream. These components are removed because they can form acidic solutions when they contact water, which will cause corrosion problems in gas pipelines. In a sweetening process, different types of ethanolamine can be used, including monoethanolamine (MEA), diethanolamine (DEA), diglycolamine (DGA) and methyldiethanolamine (MDEA). Hydrogen sulfide and carbon dioxide are absorbed by the ethanolamine and sweet gas leaves at the top of the absorber. The ethanolamine is heated, and acid gas (hydrogen sulfide and carbon dioxide gases) and water vapor are obtained. The water is removed while the acid gas can be flared or further treated in a sulfur recovery unit to separate out elemental sulfur. Finally, the lean ethanolamine is returned to the absorber.
Gas Transmission	The transport (usually by pipelines) of natural gas at high pressure from producing areas to consuming areas.
Gas Transmission and Storage	Natural gas transmission is the transport (usually by pipelines) of natural gas at high pressure from producing areas to consuming areas. Natural gas storage is the

Term	Definition
	accumulation of natural gas in caverns, spheres or in a liquefied state at facilities usually located close to consuming areas for use in servicing peak demands.
Gas Well	Any well which produces natural gas not associated or blended with crude petroleum oil at the time of production or produces more than 100,000 cubic feet of natural gas for each barrel of crude petroleum oil from the same producing horizon. • Natural gas not associated or blended with crude petroleum oil at the time of production. • Hydrocarbons having a gas-to-oil ratio of greater than 100,000 cubic feet of natural gas for each barrel of crude petroleum oil from the same producing horizon. • Natural gas from a formation or producing horizon productive of gas only encountered in a wellbore through which crude petroleum oil also is produced through the inside of another string of casing or tubing.
Gas-Condensate-Glycol (GCG) Separator	A two- or three-phase separator through which the ‘‘rich’’ glycol stream of a glycol dehydration unit is passed to remove entrained gas and hydrocarbon liquid. The GCG separator is commonly referred to as a flash separator or flash tank.
Gas-to-Oil Ratio (GOR)	The number of standard cubic meters of natural gas produced per liter of crude oil or other hydrocarbon liquid.
Gate Station	A distribution facility located adjacent to a transmission facility where gas is odorized and flows through a splitter system for distribution to different districts or areas. The inlet gas is often metered, heated, and the pressure reduced. These stations may have multiple metering and pressure regulating runs.
Glycol Dehydrator	A device in which a liquid glycol including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes ‘‘rich’’ glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The ‘‘lean’’ glycol is then recycled.
Glycol Dehydrator Reboiler Vent	The vent through which exhaust from the reboiler of a glycol dehydrator passes from the reboiler to the atmosphere or to a control device.
Greenhouse Gases	Substances involved in climate change. The most important greenhouse gases are CO_2, CH_4 and nitrous oxide (N_2O).
Heat Rate	The amount of heat energy (based on the net or lower heating value of the fuel), which must be input to a combustion device to produce the rated power output. Heat rate is usually expressed in terms of net J/kWh.

Term	Definition
Heater Treater	A vessel that heats an emulsion and removes water and gas from the oil to raise it to a quality acceptable for a pipeline or other means of transport. A heater-treater is a combination of a heater, free-water knockout, and oil and gas separator.
Heavy Crude Oil	A category of crude oil characterized by relatively high viscosity, a higher carbon-to-hydrogen ratio, and a relatively higher density - typically 920 to 1000 kg/m^3 (i.e., 10.0 to 22.3° API). Heavy crude oil typically is more difficult to extract with conventional recovery techniques and is more costly to refine.
High Vapor Pressure Hydrocarbon	Any hydrocarbon or stabilized hydrocarbon mixture with a Reid vapor pressure greater than 14 kPa.
High Vapor Pressure Pipeline	Pipeline system transporting hydrocarbon mixtures in the liquid or quasi-liquid state with a vapor pressure greater than 110 kPa absolute at 38ºC. Some examples of these hydrocarbons are liquid ethane, ethylene, propane, butanes, and pentanes.
Hot Water Extraction	An extraction process whereby oil sand, hot water, steam, and reagents are mixed to extract bitumen at a temperature of about 80°C.
Hydrate Control	The suppression of hydrate formation in natural gas gathering systems by dehydration, methanol addition or heat addition.
Hydrocarbon Dew-Point Control	A process for removing condensable hydrocarbons from natural gas to control the temperature at any given pressure at which liquid hydrocarbon initially condenses from a gas or vapor.
Incinerator	An enclosed combustion device that is used for destroying organic compounds. Auxiliary fuel may be used to heat waste gas to combustion temperatures. An energy recovery section is not physically formed into one manufactured or assembled unit with the combustion section; rather, the energy recovery section is a separate section following the combustion section and the two are joined by ducts or connections carrying flue gas. The above energy recovery section limitation does not apply to an energy recovery section used solely to preheat the incoming vent stream or combustion air.
Industrial Disposal Well	A well used for the disposal of processing wastes from a refinery or chemical plant or brine from preparation or operation of a storage cavern.
Industrial Meter Set	Metering facility that transfers gas from the distribution system to a large industrial customer. Typically, gas is supplied at intermediate or high pressure (400 to 3000 kPag [60 to 435 psig] or more) and is metered and pressure regulated.
Injection Facility	Facility constructed and operated for the purpose of moving (waste) product(s) into a petroleum reservoir.
Injection Well	A well that is used primarily to inject fluids into a reservoir as part of an enhanced recovery, experimental, or pilot scheme.

Term	Definition
Inlet Separation	A vessel located at the entrance to a hydrocarbon facility that separates the incoming stream into different components, such as gas and liquids.
In-Situ Recovery	Recovery of bitumen (oil sands) from a reservoir using a series of wells. This contrasts with oil sands recovery by mining.
Integral Compressor	A reciprocating compressor that shares a common crankshaft and crankcase with the engine.
Key Sources	Based on the IPCC (2000) definition, key source categories are those categories that, when ranked from largest to smallest based on their emission contributions, collectively account for the first 95 percent of total emissions at the site.
Lease Fuel	Natural gas used in well, field, and lease operations (such as gas used in drilling operations, heaters, dehydrators, and field compressors) and as fuel in natural gas processing plants.
Lease Separator	Facility located at the surface for the purpose of separating casinghead gas from produced crude oil and water at the temperature and pressure conditions of the separator.
Light Crude Oil	A category of crude oil characterized by relatively low viscosity, a lower carbon-to-hydrogen ratio, and a relatively lower density - typically less than 870 kg/m^3 (greater than 31.1° API).
Line Heater	An indirectly fired heater used to heat the fluid in the pipeline to above hydrate or freezing temperatures.
Liquefied Natural Gas (LNG)	Natural gas that has been refrigerated to –160°C to condense it into a liquid. The liquefaction process removes most of the water vapor, butane, propane, and other trace gases that are usually included in ordinary natural gas. The resulting LNG is usually more than 98 percent pure methane.
Liquefied Petroleum Gas (LPG)	A natural gas mixture composed of mainly ethane, propane, and butanes, with small amounts of pentanes plus (C_5+) in any combination. The fluid is usually gaseous under standard reference conditions but becomes a liquid under pressure.
Loading/Unloading Losses	When tankers (truck, rail or marine) are used to transport hydrocarbons a certain quantity of hydrocarbon vapors may be released to the atmosphere during loading and unloading operations. Emissions occur when vapors in a tanker are expelled as liquid is added. The quantity of emissions is dependent on the degree of saturation of the vapor space, the type of loading that is employed (i.e., splash or submerged), properties of the product and the amount of product transferred.
LPG Storage	A facility for storing liquefied petroleum gas (e.g., C_2, C_3 or C_4). Typically, the LPG is stored in pressurized spherical or cylindrical steel tanks, but it may also be stored in caverns and various refrigerated containers.

Term	Definition
Marine Terminal	System or arrangement of tanks and other surface equipment for receiving oil from, or transferring oil to, marine tankers.
Market	The industrial, commercial, and residential demand for a product.
Medium Crude Oil	A category of crude oil characterized as having a moderate viscosity, carbon-to-hydrogen ratio, and density - typically 870 to 920 kg/m^3 (i.e., 22.3 to 31.1° API).
Meter Station	A facility whose purpose is to measure the volume of gas passing through a pipeline. Orifice meters are used in most cases but turbine, vortex shedding, and ultrasonic meters are also used.
Methane Content of Natural Gas	The volume of methane contained in a unit volume of natural gas at standard temperature, 15°C, and pressure, 101.325 kPa.
Miscellaneous Pipeline Equipment	Aboveground or exposed equipment components (e.g., isolation/block valves, pressure-relief valves, connectors, etc.) used on the pipeline that do not occur at an actual distribution station. Buried components are deemed to be part of the piping.
Natural Gas	A naturally occurring mixture of hydrocarbon and non-hydrocarbon compounds existing in the gaseous phase or in solution with hydrocarbon liquids in geologic formations beneath the earth's surface. The principal hydrocarbon constituent is methane.
Natural Gas Battery	A system or arrangement of surface equipment that receives primarily gas from one or more wells prior to delivery to a gas gathering system, to market, or to other disposition. Gas batteries may include equipment for measurement and for separating inlet streams into gas, hydrocarbon liquid, and/or water phases. There are many occurrences of gas battery codes being assigned for the purpose of being a proration hub. In these instances, there is no equipment onsite except a meter.
Natural Gas Cycling	An enhanced petroleum recovery technique that takes produced natural gas and condensate and injects it back into the reservoir to increase pressure and increase the production of natural gas liquids.
Natural Gas Group Battery	A production facility consisting of two or more flow-lined natural gas wells having individual separation and measurement equipment but with all equipment sharing a common surface location.
Natural Gas Injection	An enhanced crude oil recovery technique in which natural gas is compressed into a producing reservoir through an injection well to drive oil to the well bore and the surface.
Natural Gas Processing Plant	Natural gas processing facility for extracting from natural gas helium, ethane, or natural gas liquids, and/or the fractionation of mixed NGL to natural gas products. A natural gas processing plant may also include natural gas purification processes for upgrading the quality of the natural gas to be marketed to meet contract specifications (i.e., for removing contaminants such as water, H_2S, CO_2, and possibly adjusting the heating value by the addition or removal of nitrogen). The

Term	Definition
	inlet natural gas may or may not have been processed through lease separators and field facilities.
Natural Gas Proration (or Field gate) Battery	A production facility consisting of two or more flow-lined natural gas wells having common separation and measuring equipment. Total production is prorated to each well based on individual well tests. Individual well production tests can occur at the central site or at remote satellite facilities.
Natural Gas Satellite Battery	A small group of surface equipment (not including storage tanks) located between multiple wells and the main natural gas battery that is intended to separate and measure the production from each well, after which the production is recombined and piped to the main natural gas battery for treating and storage or delivery.
Natural Gas Single Battery	A production facility for a single gas well where production is measured at the wellhead. Production is delivered directly and is not combined with production from other wells prior to delivery to a gas plant, gas gathering system, or other disposition.
Natural Gas Test Battery	A production facility for a natural gas well testing gas production prior to commencement of regular production.
Natural Gas Gathering System	A facility consisting of gas lines used to move products from one facility to another. The facility may also include compressors and/or line heaters.
NGL Storage	A facility for storage of natural gas liquids (usually in aboveground atmospheric storage tanks featuring floating roofs or a gas blanketing and vapor recovery system).
Non-Associated Natural Gas	Natural gas that is produced from a predominantly natural gas pool (e.g., gas that is not associated with crude oil, including bitumen).
Observation Well	A well that is used to monitor performance in an oil or gas reservoir, oil sands deposit, or aquifer.
Offshore	The geographic area which lies seaward of the coastline. In general, the term "coastline" means the line of ordinary low water along that portion of the coast which is in direct contact with open sea or the line marking the seaward limit of inland water.
Offshore Production Platform	Platform from which development wells are drilled and that carries all the associated processing plants and other equipment needed to maintain a field in production.
Offshore Well	A well that is bottomed at or produces from a point that lies seaward of the coastline.
Oil Production	The output of crude oil by oil production facilities.
Oil Shale	A laminated, sedimentary rock that contains a solid, waxy hydrocarbon called kerogen which is commingled with the rock structure. Shale oil is the

Term	Definition
	hydrocarbon produced from the decomposition of the kerogen when oil shale is heated in an oxygen-free environment. Raw shale oil resembles a heavy, viscous, low-sulfur high-nitrogen crude oil but can be upgraded to produce a good-quality sweet crude oil.
Oil Transmission	The transport (by pipelines, tanker, truck, or rail car) of crude oil from producing areas to upgraders and refineries.
Oil Transmission System	The system for transport (by pipelines, tanker, truck, or rail car) of crude oil from producing areas to upgraders and refineries.
Oil Well	Any well which produces one barrel or more of crude petroleum oil to each 100,000 cubic feet of natural gas.
Open-Ended Valves and Lines	Any valve that may release process fluids directly to the atmosphere in the event of leakage past the valve seat. The leakage may result from improper seating due to an obstruction or sludge accumulation, or because of a damaged or worn seat. An open-ended line is any segment of pipe that may be attached to such a valve and that opens to the atmosphere at the other end. Few open-ended valves and lines are designed into process systems. However, actual numbers can be quite significant at some sites due to poor operating practices and various process modifications that may occur over time. Some common examples of instances where this type of source may occur are listed below: •Scrubber, compressor-unit, station, and mainline blowdown valves. • Supply-gas valve for a gas-operated engine starter (i.e., where natural gas is the supply medium). • Instrument block valves where the instrument has been removed for repair or other reasons. • Purge or sampling points.
Operator	The entity appointed by venture stakeholders to take primary responsibility for day-to-day operations and activities for a specific plant or activity.
Pentanes Plus	A mixture of hydrocarbons, mostly pentanes and heavier, extracted from natural gas. It includes natural gasoline, isopentane and gas plant condensate.
Petroleum	A term sometimes used as a substitute for crude oil and sometimes as a collective term for natural gas and crude oil.

Term	Definition
Petroleum Bulk Terminals	System or arrangement of tanks and other surface equipment operated by refining, pipeline, and bulk terminal companies which (1) receive their principal products by tankers, barges, or pipelines, or (2) have a total combined capacity of 8 000 m^3 (50,000 barrels) or more, regardless of the transportation means by which products are received.
Petroleum Distribution Network	The network or piping, tankers, trucks, rail cars and transportation equipment used to deliver petroleum products to customers.
Petroleum Liquids	Liquid hydrocarbons, that is crude oil, diluted bitumen, natural gas liquids, condensate, etc.
Petroleum Market	The industrial, commercial, and residential demand for petroleum products.
Pig	A device, with optional elastomer cups, that is inserted into a pipeline and pushed along by the flowing fluid to perform any one of the following functions: cleaning, displacement, batching, or internal inspection. It gets its name from the squealing noises the pipeline pigs made when first used.
Pig Launcher	A piping arrangement that allows pigs to be launched into a pipeline without stopping flow.
Pig Passage Indicator	A device installed on a pipeline to indicate the passage of a pig. A visual or electrical indication, or combination thereof, is given when the pig passes. Pig indicators can also be used in automated systems for valve sequencing. A non-intrusive model, which does not require a tap, is also available.
Pig Receiver	A piping arrangement that allows pigs to be removed from a pipeline without stopping flow.
Pipeline Fuel	Natural gas consumed in the operation of a natural gas pipeline, primarily in compressors.
Pipeline Leak	Fugitive emission through a small opening in the wall of the pipeline (e.g., due to corrosion or material defects) or from valves, fittings or connectors attached to that pipeline.
Pipeline Terminal	System or arrangement of tanks and other surface equipment principally for receiving oil from, and transferring oil to, pipelines. The terminal may also feature facilities for blending petroleum liquids and loading and/or unloading tank trucks, tank rail cars and marine tankers.
Pipelines	A network of pipes used to transport gases and liquids.
Plastic Pipelines	Pipelines made of various types of plastic (i.e., including polyethylene, polyvinyl chloride, ABS, etc.).
Pool	Synonymous with the term reservoir; however, in certain situations, a pool may consist of more than one reservoir.

Term	Definition
Power Output	For engines it is the net shaft power available after all losses and power take-offs (e.g., ignition-system power generators, cooling fans, turbo chargers and pumps for fuel, lubricating oil, and liquid coolant) have been subtracted. For heaters and boilers, it is the net heat transferred to a target process fluid or system.
Pressure-Relief or Safety Valves	These are used to protect process piping and vessels from being accidentally over-pressured. They are spring loaded so that they are fully closed when the upstream pressure is below the set point, and only open when the set point is exceeded. Relief valves open in proportion to the amount of overpressure to provide modulated venting. Safety valves pop to a full-open positions on activation. When relief or safety valves reseat after having been activated, they often leak because the original tight seat is not regained either due to damage of the seating surface or a build-up of foreign material on the seat plug. As a result, they are often responsible for fugitive emissions. Another problem develops if the operating pressure is too close to the set pressure, causing the valve to "simmer" or "pop" at the set pressure. Gas that leaks from a pressure-relief valve may be detected at the end of the vent pipe (or horn). Additionally, there normally is a monitoring port located on the bottom of the horn near the valve.
Primary Recovery	The production of crude oil using natural reservoir pressure and/or a simple downhole pump.
Process Heater	An enclosed device using a controlled flame, the primary purpose of which is to transfer heat to a process fluid or process material that is not a fluid, or to a heat transfer material for use in a process (rather than for steam generation).
Process Vessel	A heater, dehydrator, separator, treater, or any vessel used in the processing or treatment of produced gas or oil.
Produced Water	Water that is extracted from the earth from a crude oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.
Produced Water Storage	Atmospheric storage tanks used to store produced water from oil and gas facilities prior to transporting it to a disposal or re-injection facility.
Producing Well	A well producing hydrocarbons from a petroleum reservoir or a bituminous [oil] sands deposit.
Product Blender	A storage tank or inline mixer for blending crude oils and condensates to meet product specifications.

Term	Definition
Production Well	Any hole drilled in the earth from which crude oil, condensate, or field natural gas is extracted.
Products of Incomplete Combustion	These are any compounds, excluding CO_2, H_2O, SO_2, HCl and HF, that contain C, H, S, Cl or F and occur in the flue gas stream. These compounds may result from thermodynamic, kinetic or transport limitations in the various combustion zones. All input combustibles are potential products of incomplete combustion. Intermediate substances formed by dissociation and recombination effects may also occur as products of incomplete combustion (CO is often the most abundant combustible formed).
Protected Steel Pipelines	Steel pipelines that are cathodically protected.
Pump Seals	Positive displacement pumps are normally used for pumping hydrocarbon liquids at oil and gas facilities. Positive displacement pumps have a reciprocating piston, diaphragm, or plunger, or else a rotary screw or gear. Packing, with or without a sealant, is the simplest means of controlling leakage around the pump shaft. It may be used on both the rotating and reciprocating pumps. Specially designed packing materials are available for different types of service. The selected material is placed in a stuffing box and the packing gland is tightened to compress the packing around the shaft. All packings leak and generally require frequent gland tightening and periodic packing replacement. Particulate contamination, overheating, seal wear, sliding seal leakage and vibration will contribute to increased leakage rates over time.
Pumping Station	System or arrangement of tanks and other surface equipment located at intervals along a main pipeline to maintain flow to the terminal point.
Pumping Well	An oil well that requires a pump to bring the oil to the surface. Either a pumpjack (polished rod pump) or a progressive cavity pump may be used.
Pumps	Mechanical devices used to cause liquids to flow by physical displacement.
Purge Gas	For safe operation, flare systems require a constant purge of gas (usually fuel gas). The purge rate is usually determined when the system is designed. The purge gas rate is sometimes set by installing an appropriate orifice in the purge fuel line but most often it is set by partially opening a valve. Purge gas rates are not typically measured.
Receipt Meter Station	A meter station for measuring the amount of gas being supplied by a given source (e.g., gas processing plant or a gas battery) to a natural gas transmission system.

Term	Definition
Reciprocating Compressor	A piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the drive shaft.
Reciprocating Compressor Packing Systems	Are used on reciprocating compressors to control leakage around the piston rod on each cylinder. Conventional packing systems have always been prone to leaking a certain amount, even under the best of conditions. According to one manufacturer, leakage from within the cylinder or through any of the various vents will be on the order of 1.7 to 3.4 m^3/h under normal conditions and for most gases. However, these rates may increase rapidly as normal wear and degradation of the system occurs.
Reduced Sulphur Compounds (RSCs)	Any compounds containing the sulfur atom in its reduced oxidation state. These are taken to be any sulphur-containing compounds except SOx.
Refinery	A plant where crude oil is separated by distillation into light and heavy fractions which are then converted by various methods, such as cracking, reforming, alkylation, polymerization, and isomerization, into usable products or feedstocks for other processes. The mixtures of new compounds formed are separated using methods such as fractionation and solvent extraction.
Refrigeration	A process for chilling natural gas to extract condensable heavier-than-methane hydrocarbon fractions (e.g., C2, C3, and C4+) and controlling the hydrocarbon dew point of the natural gas stream. This may be done using a Joule-Thompson or closed loop propane refrigeration unit for shallow cut extraction. For deep cut extraction a turbo expander and propane refrigeration unit are typically used.
Regulation Station	A facility whose purpose is to regulate the pressure of gas passing through a pipeline to a set level.
Reinjection	The injection of a gas or liquid back into the reservoir from which it originated.
Relief Device	A device used only to release an unplanned, non-routine discharge to avoid safety hazards or equipment damage. A relief device discharge can result from an operator error, a malfunction such as a power failure or equipment failure, or other unexpected cause that requires immediate venting of gas from process equipment in order to avoid safety hazards or equipment damage.
Reported Venting Storage Losses	The sum of all vented volumes stated in production accounting statistics. These comprise normal evaporation losses, flashing losses and unintentional gas carry-through to storage tanks due to leakage past drain valves into tank inlet headers, inefficient gas-liquid separation in upstream vessels, malfunctioning level controllers, leakage past the seat of level control valves, or unintentional storage of high vapor pressure liquids in atmospheric tanks.

Term	Definition
	Evaporative losses occur when volatile hydrocarbon products are stored in tanks that are vented to the atmosphere. As the product evaporates, the vapor space in the tank becomes saturated with vapors. These vapors are expelled during tank filling (working losses) and due to diurnal temperature and pressure changes (breathing losses). Flashing losses are characterized by a rapid boiling process. They occur when product with a true vapor pressure near or greater than atmospheric pressure is placed in atmospheric storage tanks or when hot product is run down to a tank containing a lighter product causing it to boil.
Reservoir	A porous and permeable underground formation containing an individual and separate natural accumulation of producible hydrocarbons (oil and/or gas) which is confined by impermeable rock or water barriers and is characterized by a single natural pressure system. In most situations, reservoirs are classified as oil reservoirs or as gas reservoirs by a regulatory agency. In the absence of a regulatory authority, the classification is based on the natural occurrence of the hydrocarbons in the reservoir as determined by the operator.
Residential Meter Set	Customer metering facilities for gas sales to a residential customer. They include both pressure regulation and measurement. The regulator typically reduces pressure from distribution pressure to 1.7 kPag (0.25 psig).
Residue Gas	Natural gas from which gas plant products (natural gas liquids), and in some cases non-hydrocarbons, have been extracted in natural gas processing plants.
Rural Gas Co-ops	A natural gas distribution system that delivers natural gas to rural customers by pipeline or other transport equipment.
Safety Device	A device that meets both of the following conditions: it is not used for planned or routine venting of liquids, gases, or fumes from the unit or equipment on which the device is installed; and it remains in a closed, sealed position at all times except when an unplanned event requires that the device open for the purpose of preventing physical damage or permanent deformation of the unit or equipment on which the device is installed in accordance with good engineering and safety practices for handling flammable, combustible, explosive, or other hazardous materials. Examples of unplanned events which may require a safety device to open include failure of an essential equipment component or a sudden power outage.
Sales Meter Station	A meter station for measuring the amount of natural gas being withdrawn from a gas transmission system by a customer (e.g., gas distribution system, farm or industrial end user). It might include pressure-regulating equipment.
Secondary Recovery	The production of crude oil using reservoir flooding with water or natural gas.
Service Lines	Service lines are usually short, small diameter pipelines that delivers gas from distribution main or transmission pipeline to the customer. They are usually made

Term	Definition
	of steel pipe or steel tubing (either cathodically protected or not), or plastic (usually polyethylene, but sometimes PVC or other plastic), although copper tubing was also sometimes used in the past. Sizes vary from ½ to 2 NPS, with some commercial or industrial customers having service lines of much larger diameter. Service lines tied into transmission lines might operate at pressures exceeding the distribution pressure. They are called “high-pressure service lines" and require double regulation at the customer meter set. Typically, they operate at pressures above 860 kPag (125 psig). Steel pipelines are not cathodically protected.
Service Well	A well drilled or completed for the purpose of supporting production in an existing field. Wells of this class are drilled for the following specific purposes: • Gas injection (natural gas, propane, butane, or flue-gas). • Water injection. • Steam injection. • Air injection. • Saltwater injection, water supply for injection. • Observation, injection for in-situ combustion.
Shallow Natural Gas Well	A gas well less than 1000 m deep. The gas is usually low pressure and sweet. In some cases, shallow gas may only require dehydration prior to sales.
Shut-in Well	A well that has been completed but is not producing. A well may be shut-in for tests, repairs, or awaiting construction of gathering or flow lines or better economic conditions.
Solution Natural Gas	Natural gas that is in solution with produced crude oil.
Sour Crude Oil	Crude oil containing free sulfur, hydrogen sulfide or other sulfur compounds.
Sour Natural Gas	Raw natural gas that contains quantities of H_2S, CO_2, and other sulfide-based compounds in sufficient quantities to pose a public safety hazard if released or to result in unacceptable off-lease odors if vented to the atmosphere.
Stabilizer	A heated pressure vessel used to boil off the volatile fraction of a liquid stream to produce a less volatile product suitable for storage in tanks at atmospheric pressure.

Term	Definition
Standard Reference Conditions	Most equipment manufacturers reference flow, concentration, and equipment performance data at ISO standard conditions of 15°C, 101.325 kPa, sea level and 0.0 percent relative humidity.
Steam Generators	A boiler used to generate steam for use in thermal oil production schemes.
Steam Methane Reforming	A process commonly used to convert natural gas to hydrogen for use in hydrotreating processes.
Steam Separator	A vessel for separating steam and condensed water.
Steam-Assisted Gravity Drainage (SAGD) Well	A well that is used to produce heavy oil, particularly bitumen, with the assistance of thermal heating by steam.
Stock Tank Vapors	The small volume of dissolved gas present in the oil storage tanks that may be released from the tanks.
Storage	Most transmission systems incorporate the use of storage caverns or spheres to help balance daily and seasonal variations in loads, and, therefore, can operate at nearly full capacity much of the time.
Storage Vessel	A tank or other vessel that is designed to contain an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water and that is constructed primarily of non-earthen materials (e.g., wood, concrete, steel, plastic) that provide structural support.
Storage Vessel with the Potential for Flash Emissions	Any storage vessel that receives hydrocarbon liquids containing dissolved natural gas that will evolve from solution when the fluid pressure is reduced.
Storage Well	A well that is used to inject hydrocarbons into a storage reservoir or cavern.
Sub-Sea Wellhead	A wellhead installed on the sea floor and controlled remotely from a platform, a floating production facility or land.
Sulphur Recovery	A sulfur recovery unit converts hydrogen sulfide removed from sour gases and hydrocarbon streams to elemental sulfur. The most widely used recovery system is the Claus process, which uses both thermal and catalytic-conversion reactions. A typical process produces elemental sulfur by burning hydrogen sulfide under controlled conditions. Knockout pots are used to remove water and hydrocarbons from feed gas streams. The gases are then exposed to a catalyst to recover additional sulfur. Sulphur vapor from burning and conversion is condensed and recovered.
Suspended Well	A well in which production or injection operations have ceased for an indefinite period.
Suspension	The cessation of normal production, operation, or injection activities at a facility.

Term	Definition
Sweet Natural Gas	Raw natural gas with a relatively low concentration of sulfur compounds, such as hydrogen sulfide.
Tank	A device designed to contain materials produced, generated, and used by the petroleum industry that is constructed of impervious materials, such as concrete, plastic, fiberglass-reinforced plastic, or steel that provide structural support.
Tank Farm	System or arrangement of tanks or other surface equipment associated with the operation of a pipeline that may include measurement equipment and line heaters but does not include separation equipment or storage vessels at a battery.
Tank Truck	Includes all road vehicles carrying liquid or gaseous cargo in bulk.
Tanker	Any ship or other watercraft carrying liquid or gaseous cargo in bulk.
Terminal	Plant and equipment designed to process crude oil or gas to remove impurities and water.
Tertiary Recovery	The production of crude oil using more sophisticated techniques such as reservoir flooding with CO_2 or lighter hydrocarbons such as ethane. Tertiary recovery also encompasses all thermal recovery techniques.
Thermal Efficiency	The percentage or portion of input energy converted to useful work or heat output. For combustion equipment, typical convention is to express the input energy in terms of the net (lower) heating value of the fuel. This results in the following relation for thermal efficiency: n = Thermal Efficiency = {(UsefulWork/HeatOutput)/(NetHeat/EnergyInput)}*100% Alternatively, thermal efficiency may be expressed in terms of energy losses as follows: n = {1-((Sum(EnergyLoses))/(NetHeat/EnergyInput)}*100% Losses in thermal efficiency occur due to the following potential factors: • Exit combustion heat losses (i.e., residual heat value in the exhaust gases). • Air infiltration. • Incomplete combustion. • Mechanical losses (e.g., friction losses and energy needed to run cooling fans and lubricating-oil pumps).

Term	Definition
Thermal Recovery	The production of crude oil, which involves the use of one or more thermal techniques whereby heat is introduced into the crude oil reservoir or bituminous sands (oil sands) deposit to enhance the ability of the crude oil to flow and thereby facilitate its recovery.
Total Hydrocarbons	All compounds containing at least one hydrogen atom and one carbon atom, with the exception of carbonates and bicarbonates.
Total Organic Compounds (TOC)	TOC comprises all VOCs plus all non-reactive organic compounds (i.e., methane, ethane, methylene chloride, methyl chloroform, many fluorocarbons, and certain classes of per fluorocarbons).
Total Petroleum Stocks	The volume of crude oil (including lease condensate), natural gas plant liquids and petroleum products held by crude oil producers, storers of crude oil, companies transporting crude oil by water, crude oil pipeline companies, refining companies, product pipeline companies, and bulk terminal companies. Included are domestic oil and foreign oil that have cleared customs for domestic consumption (i.e., foreign oil in-transit to the receiving country and foreign oils held in bonded storage, to include oils in the foreign trades zone, are excluded from these stock statistics). All stocks are reported on a custody basis, regardless of ownership of the oils.
Transmission Farm Tap	Direct gas sales from a transmission pipeline to an individual customer, usually in rural areas where access to gas distribution system is not available. These facilities usually have only pressure regulating equipment (gas might be provided free of charge as a consideration for an easement, or the meter is located by the residence as part of the customer meter set).
Transmission Pipeline	A pipeline used to transport processed, unodorized natural gas to market (i.e., to gas distribution systems and major industrial customers). Most transmission pipelines also have some farm taps that provide gas to farmers located along the pipeline in areas where service from distribution systems is not readily available. The pipelines are usually constructed of steel, although aluminum is used for some lower pressure applications (generally up to 3450 kPa or 500 psig). The pipe sizes range from 60.3 mm to 1219.2 mm O.D. (2 to 48 NPS), with the mid-range sizes most common. The operating pressures typically range from 1380 to over 6900 kPag (200 to 1000+ psig).
Transmission Station	A station associated with a natural gas transmission pipeline that handles unodorized gas and which meters and/or regulate the gas pressure. It may be a Receipt/Sales Station, Border Meter Station, or Transmission Farm Tap.
Transmission Stations	Transmission stations are stations associated with transmission pipelines and handle unodorized gas. They meter and/or regulate the gas pressure. They consist of Receipt/Sales Stations, Border Meter Stations, and Transmission Farm Taps.

Term	Definition
Transport Systems	A system for transporting crude oil, NGL, and LPG to upgraders and refineries.
Treating	The application of processes to remove impurities from hydrocarbon streams such as water, carbon dioxide, hydrogen sulfide, and nitrogen.
Truck Terminal	System or arrangement of tanks and other surface equipment receiving crude oil by truck for the purpose of delivering crude oil into a pipeline.
Turnaround	A scheduled large-scale maintenance activity wherein an entire process unit is taken off stream for an extended period for comprehensive revamp and renewal.
Valve	A device for controlling the flow of a fluid. There are three main locations on a typical valve where leakage may occur: (1) from the valve body and around the valve stem, (2) around the end connections, or (3) past the valve seat. Leaks of the first type are referred to as valve leaks. Emissions from the end connections are classified as connector leaks. Leakage past the valve seat is only a potential source of emissions if the valve, or any downstream piping, is open to the atmosphere. This is referred to as an open-ended valve or line. The potential leak points on each of the different types of valves are, as applicable, around the valve stem, body seals (e.g., where the bonnet bolts to the valve body, retainer connections), body fittings (e.g., grease nipples, bleed ports), packing guide, and any monitoring ports on the stem packing system. Typically, the valve-stem packing is the most likely of these parts to leak. The different valve types include gate, globe, butterfly, ball, and plug. The first two types are a rising-stem design, and the rest are quarter-turn valves. Valves may either be equipped with a hand-wheel or lever for manual operations, or an actuator or motor for automated operation.
Vent and Flare Systems	Venting and flaring are common methods of disposing of waste gas volumes at oil and gas facilities. The stacks are designed to provide safe atmospheric dispersion of the effluent. Flares are normally used where the waste gas contains odorous or toxic components (e.g., hydrogen sulfide). Otherwise, the gas is usually vented. Typically, separate flare/vent systems are used for high- and low-pressure waste gas streams.
Venting	Emissions to the atmosphere by design or operational practice. They may occur on either a continuous or intermittent basis.
Volatile Organic Compounds (VOC)	Any compound of carbon, excluding carbon monoxide and carbon dioxide, which participates in atmospheric chemical reactions. This excludes methane, ethane, methylene chloride, methyl chloroform, acetone, many fluorocarbons, and certain classes of per fluorocarbons.

Term	Definition
Wastewater Injection Facility	Facility constructed and operated for the purpose of moving waste produced water (brine) into a petroleum reservoir.
Water Storage	Tankage used to store produced water at oil and gas production and processing facilities prior to be transported to a disposal or re-injection facility.
Water Treatment Facility	A facility for removing suspended and dissolved solids and salts prior to being used to generate steam.
Well	A hole drilled in the earth for the purpose of (1) finding or producing crude oil or natural gas; or (2) providing services related to the production of crude oil or natural gas.
Well Drilling	The process of boring a hole from the surface to a potential producing zone in an oil or gas reservoir. Diesel engines are typically used to power the drilling mechanism.
Well Drill-Stem Test	When the target zone has been reached, a drill-stem test may be performed to determine the production potential of the zone. This test occurs when the drilling rig is on the well. During a test, the zone is produced through the center of the drill-stem. At the surface, the gas and liquid phases are separated and measured. If it is a sour well, the gas phase is flared; otherwise, the gas may be vented to the atmosphere.
Well Servicing (or Workover)	Work performed on a well after its initial completion to repair downhole equipment or to increase production rates.
Well Testing	Flow testing conducted to determine the deliverability of a well. (Sometimes the test may be conducted into a flow or gathering line; however, more often the liquids are produced into temporary tankage brought on site for the test, and the gas phase is either vented or flared.).
Wellhead	The equipment fitted to the top of a well casing to maintain surface control of the well (i.e., outlets, valves, blowout preventers, etc.).
Wellsite Facilities	The facilities located at an oil or gas well site. These may include separation and metering, line heaters, chemical injection, compression or pumping facilities, dehydration, or storage for produced liquids.
Wet Natural Gas	Field natural gas that needs to be processed to extract natural gas liquids to meet contract hydrocarbon dew point requirements.
Workovers and Well Servicing	Work performed on a well after its initial completion to repair downhole equipment or to increase production rates.

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6. APPENDICIES

APPENDIX A: Equations Programmed into the *SMART Plus* Facility Template

Combustion: Solid fuels

Equation 1: Calculate emissions of CO2 from solid fuel combustion

$$Emissions = F * H * C * \frac{R}{100} * \frac{M_{CO2}}{M_C}$$

Where, for each of the eight types of available solid fuels:

F = Amount of fuel combusted (from user input)
H = Higher heating value (defined in template)
C = Carbon content (defined in template)
R = Carbon oxidation rate as a percentage (defined in template)
M_{CO2} = Molecular weight of CO_2 (defined in template)
M_C = Molecular weight of carbon (defined in template)

Equation 2: Calculate emissions of CH4, N2O, NOx, CO, or NMVOC from solid fuel combustion:

$$Emissions = F * E * N$$

Where, for each of the eight types of available solid fuels:

F = Amount of fuel combusted (from user input)
E = Emission factor (defined in template for each gas)
N = Unit conversion for emission factor (defined in template)

Equation 3: Calculate emissions of SO2 from solid fuel combustion:

$$Emissions = F * S * \frac{M_{SO2}}{M_S}$$

Where, for each of the eight types of available solid fuels:
F = Amount of fuel combusted (from user input)
S = Solid fuel mass percent (defined in template)
M_{SO2} = Molecular weight of SO_2 (defined in template)
M_S = Molecular weight of sulphur (defined in template)

Combustion: Liquid fuels

Equation 4: Calculate emissions of CO2 from liquid fuel combustion:

$$Emissions = F * H * C * \frac{R}{100} * \frac{M_{CO2}}{M_C}$$

Where, for each of the 10 types of available liquid fuels:
F = Amount of fuel combusted (from user input)
H = Higher heating value (defined in template)
C = Carbon content (defined in template)
R = Carbon oxidation rate as a percentage (defined in template)
M_{CO2} = Molecular weight of CO_2 (defined in template)
M_C = Molecular weight of carbon (defined in template)

Equation 5: Calculate emissions of CH4, N2O, NOx, CO, or NMVOC from liquid fuel combustion:

$$Emissions = F * \frac{1}{D} * E * N$$

Where, for each of the 10 types of available liquid fuels:
F = Amount of fuel combusted (from user input)
D = Density of the fuel (defined in template)
E = Emission factor (defined in template for each gas)
N = Unit conversion for the emission factor (defined in template)

Equation 6: Calculate emissions of SO2 from liquid fuel combustion:

$$Emissions = F * L * \frac{M_{SO2}}{M_S}$$

Where, for each of the 10 types of available liquid fuels:

F = Amount of fuel combusted (from user input)
L = Liquid fuel mass percent (defined in template)
M_{SO2} = Molecular weight of SO_2 (defined in template)
M_S = Molecular weight of sulphur (defined in template)

Combustion: Gaseous fuels

Equation 7: Calculate emissions of CO2 from gaseous fuel combustion:

$$Emissions = F * H * C * \frac{R}{100} * \frac{M_{CO2}}{M_C}$$

Where, for each of the six types of available gaseous fuels:

F = Amount of fuel combusted (from user input)
H = Higher heating value (defined in template)
C = Carbon content (defined in template)
R = Carbon oxidation rate as a percentage (defined in template)
M_{CO2} = Molecular weight of CO_2 (defined in template)
M_C = Molecular weight of carbon (defined in template)

Equation 8: Calculate emissions of CH4, N2O, NOx, CO, or NMVOC from gaseous fuel combustion:

$$Emissions = F * H * E * N$$

Where, for each of the six types of available gaseous fuels:

F = Amount of fuel combusted (from user input)
H = Higher heating value (defined in template)
E = Emission factor (defined in template for each gas)
N = Unit conversion for emission factor (defined in template)

Equation 9: Calculate emissions of SO2 from gaseous fuel combustion:

$$Emissions = F * \frac{C_{H2S,FG}}{V} * M_{SO2}$$

Where, for each of the six types of available gaseous fuels:

F = Amount of fuel combusted (from user input)
$C_{H2S,FG}$ = H_2S content of the fuel gas (defined in template)
V = Standard volume (defined in template)
M_{SO2} = Molecular weight of SO_2 (defined in template)

Hydrocarbon venting

Equation 10: Calculate emissions of CO2 from hydrocarbon venting:

$$Emissions = Q * C_{CO2,VG} * D * 365$$

Where:

Q = Quantity of vented gas (from user input)
$C_{CO2,VG}$ = CO_2 content of vented gas (defined in template)
D = Density of CO_2 (defined in template)

Equation 11: Calculate emissions of CH4 from hydrocarbon venting:

$$Emissions = Q * C_{CH4,VG} * D * (1 - W) * 365$$

Where:

Q = Quantity of vented gas (from user input)
$C_{CH4,VG}$ = CH_4 content of vented gas (defined in template)
D = Density of CH_4 (defined in template)
W = Flare efficiency as a percentage (from user input)

Equation 12: Calculate emissions of N2O, NOx, or CO from hydrocarbon venting:

$$Emissions = Q * E * N * 365$$

Where:

Q = Quantity of vented gas (from user input)
E = Emission factor (defined in template for each gas)
N = Unit conversion for emission factor (defined in template)

Equation 13: Calculate emissions of NMVOC from hydrocarbon venting:

$$Emissions = \frac{CH_4\ emissions}{M_{CH4}} \div C_{CH4,VH} * \left(1 - C_{CH4,VH} - C_{CO2,VH} - C_{N2,VH} - C_{H2S,VH}\right) * M_{NMVOC}$$

Where:

CH_4 emissions = Result from Equation 11
M_{CH4} = Molecular weight of CH_4 (defined in template)
$C_{CH4,VH}$ = CH_4 content of vented gas (defined in template)
$C_{CO2,\ VH}$ = CO_2 content of vented gas (defined in template)
$C_{N2,VH}$ = N_2 content of vented gas (defined in template)
$C_{H2S,VH}$ = H_2S content of vented gas (defined in template)
M_{NMVOC} = Molecular weight of NMVOC (defined in template)

Equation 14: Calculate emissions of SO2 from hydrocarbon venting:

$$Emissions = Q * \frac{C_{H2S.VH}}{V}$$

Where:

Q = Quantity of gas vented (from user input)
$C_{H2S,VH}$ = H_2S content of vented gas (defined in template)
V = Standard volume (defined in template)

Hydrocarbon flaring

Equation 15: Calculate emissions of CO2 from hydrocarbon flaring:

$$Emissions = Q * \left(\left(C_{CO2,FG} * D\right) + \left(C_{CH4,FG} * W * C_{C,CH4} * \left(\frac{M_{CO2}}{M_C}\right)\right) + \left(C_{Other} * W * C_{C,Other} * \left(\frac{M_{CO2}}{M_C}\right)\right)\right) * 365$$

Where:

Q = Quantity of flared gas (from user input)
C_{CO2} = CO_2 content of flared gas (defined in template)
D = Density of CO_2 (defined in template)
$C_{CH4,FG}$ = CH_4 content of flared gas (defined in template)
W = Flare efficiency (from user input)
$C_{C,CH4}$ = Carbon content of CH_4 (defined in template)
M_{CO2} = Molecular weight of CO_2 (defined in template)
M_C = Molecular weight of carbon (defined in template)
$C_{Other,FG}$ = Other hydrocarbon content of flared gas (defined in template)
$C_{C,Other}$ = Carbon content of other hydrocarbons in flared gas (defined in template)

Equation 16: Calculate emissions of CH4 from hydocarbon flaring:

$$Emissions = Q * C_{CH4,FG} * D * (1 - W)$$

Where:

Q = Quantity of flared gas (from user input)
$C_{CH4,FG}$ = CH_4 content of flared gas (defined in template)
D = Density of CH_4 (defined in template)
W = Flare efficiency (from user input)

Equation 17: Calculate emissions of N2O from hydrocarbon flaring:

$$Emissions = Q * E * N * 365$$

Where:

Q = Quantity of flared gas (from user input)
E = Emission factor (defined in template)
N = Unit conversion for emission factor (defined in template)

Equation 18: Calculate emissions of NOx or CO from hydrocarbon flaring:

$$Emissions = Q * H * E * N$$

Where:

Q = Quantity of flared gas (from user input)
H = Higher heating value (defined in template)
E = Emission factor (defined in template)
N = Unit conversion for emission factor (defined in template)

Equation 19: Calculate emissions of NMVOC from hydrocarbon flaring:

$$Emissions = \frac{CH_4\ emissions}{M_{CH4}} \div C_{CH4,FG} * \left(1 - C_{CH4,FG} - C_{CO2,FG} - C_{N2,FG} - C_{H2S,FG}\right) * M_{NMVOC}$$

Where:

CH_4 emissions = From Equation 16
M_{CH4} = Molecular weight of CH_4 (defined in template)
$C_{CH4,FH}$ = CH_4 content of flared gas (defined in template)
$C_{CO2, FH}$ = CO_2 content of flared gas (defined in template)
$C_{N2,FH}$ = N_2 content of flared gas (defined in template)
$C_{H2S,FH}$ = H_2S content of flared gas (defined in template)
M_{NMVOC} = Molecular weight of NMVOC (defined in template)

Equation 20: Calculate emissions of SO2 from hydrocarbon flaring:

$$Emissions = Q * \frac{C_{H2S,FG}}{V} * M_{SO2} * 365$$

Where:

Q = Quantity of gas flared (from user input)
$C_{H2S,FH}$ = H_2S content of flared gas (defined in template)
V = Standard volume (defined in template)
M_{SO2} = Molecular weight of SO_2 (defined in template)

Acid gas venting

Equation 21: Calculate emissions of CO2 from acid gas venting:

$$Emissions = Q * C_{CO2,VA} * D * 365$$

Where:

Q = Quantity of vented acid gas (from user input)
$C_{CO2,VA}$ = CO_2 content of vented acid gas (defined in template)
D = Density of CO_2 (defined in template)

Equation 22: Calculate emissions of CH4 from acid gas venting:

$$Emissions = Q * C_{CH4,VA} * D * (1 - W) * 365$$

Where:

Q = Quantity of vented acid gas (from user input)
$C_{CH4,VA}$ = CH_4 content of vented acid gas (defined in template)
D = Density of CH_4 (defined in template)
W = Flare efficiency as a percentage (defined in template)

Equation 23: Calculate emissions of N2O, NOx , or CO from acid gas venting:

$$Emissions = Q * E * N * 365$$

Where:

Q = Quantity of vented acid gas (from user input)
E = Emission factor (defined in template for each gas)
N = Unit conversion for emission factor (defined in template)

Equation 24: Calculate emissions of NMVOC from acid gas venting:

- Use Equation 13 with methane emissions from Equation 22

Equation 25: Calculate emissions of SO2 from acid gas venting:

$$Emissions = Q * \frac{C_{H2S.VA}}{V}$$

Where:

Q = Quantity of acid gas vented (from user input)
$C_{H2S,VH}$ = H_2S content of vented acid gas (defined in template)
V = Standard volume (defined in template)

Acid gas flaring

Equation 26: Calculate emissions of CO2 from acid gas flaring:

$$Emissions = Q * \left(\left(C_{CO2,AF} * D\right) + \left(C_{CH4,AF} * W * C_{C,CH4} * \left(\frac{M_{CO2}}{M_C}\right)\right) + \left(C_{Other} * W * C_{C,Other} * \left(\frac{M_{CO2}}{M_C}\right)\right)\right) * 365$$

Where:

Q = Quantity of flared acid gas (from user input)
C_{CO2} = CO_2 content of flared acid gas (defined in template)
D = Density of CO_2 (defined in template)
$C_{CH4,AF}$ = CH_4 content of flared acid gas (defined in template)
W = Flare efficiency (defined in template)
$C_{C,CH4}$ = Carbon content of CH_4 (defined in template)
M_{CO2} = Molecular weight of CO_2 (defined in template)
M_C = Molecular weight of carbon (defined in template)
$C_{Other,AF}$ = Other hydrocarbon content of flared acid gas (defined in template)
$C_{C,Other}$ = Carbon content of other hydrocarbons in flared acid gas (defined in template)

Equation 27: Calculate emissions of CH4 from acid gas flaring:

$$Emissions = Q * C_{CH4,AF} * D * (1 - W)$$

Where:

Q = Quantity of flared acid gas (from user input)
$C_{CH4,AF}$ = CH_4 content of flared acid gas (defined in template)
D = Density of CH_4 (defined in template)
W = Flare efficiency (defined in template)

Equation 28: Calculate emissions of N2O, NOx , or CO from acid gas flaring:

$$Emissions = Q * E * N * 365$$

Where:

Q = Quantity of flared acid gas (from user input)
E = Emission factor (defined in template)
N = Unit conversion for emission factor (defined in template)

Equation 29: Calculate emissions of NMVOC from acid gas flaring:

- Use Equation 19 with methane emissions from Equation 27

Equation 30: Calculate emissions of SO2 from acid gas flaring:

$$Emissions = Q * \frac{C_{H2S,AF}}{V} * M_{SO2} * 365$$

Where:

Q = Quantity of acid gas flared (from user input)
$C_{H2S,FH}$ = H_2S content of flared acid gas (defined in template)
V = Standard volume (defined in template)
M_{SO2} = Molecular weight of SO_2 (defined in template)

Electric power purchases

Equation 31: Calculate emissions of CO2, CH4, N2O, NOx, CO, or NMVOC from power purchases:

$$Emissions = Q * E$$

Where:

Q = Quantity of purchased electricity (from user input)
E = Emission factor (defined in template)

Equipment leaks grand total and Compressor seals grand total

Equation 32: Calculate emissions of CH4 from equipment leaks and compressor seals:

$$Grand\ total\ missions = \sum_{1}^{20} Z_n + K$$

Where:

$$Z_n = B_{O,n} + B_{S,n} + B_{D,n}$$

Where:

$$B_{O,S,D} = \sum Emissions\ per\ component * Q * T_{O,S,D}$$

Where:

$$Emissions\ per\ component = Q * (T_s + T_O) * X_C * E$$

Where:

Z = Emissions per category
n = Category 1 through 20
K = Measured contribution (from user input)
B_O = Emissions contribution from operating period
B_S = Emissions contribution from standby period
B_D = Emissions contribution from depressurized period
Q = Quantity (from user input)
T_O = Operating time as a percentage (from user input)
T_S = Standby time as a percentage (from user input)
T_D = Depressurized time as a percentage (from user input)
X_C = Component count (defined in template)
E = Emission factor (defined in template)

Equation 33: Calculate emissions of CO2 from equipment leaks and compressor seals:

$$Emissions = \left(Grand\ total\ CH_4\ emissions * \frac{C_{CO2,CG}}{C_{CH4,CG}}\right) * \left(\frac{M_{CO2}}{V}\right) * N$$

Where:

Grand total CH_4 emissions = Result from Equation 32
$C_{CO2,CG}$ = CO_2 content of casinghead vent gas (defined in template)
$C_{CH4,CG}$ = CH_4 content of casinghead vent gas (defined in template)
M_{CO2} = Molecular weight of CO_2 (defined in template)
V = Standard volume (defined in template)
N = Unit conversion factor (defined in template)

Equation 34: Calculate emissions of NMVOC from equipment leaks and compressor seals:

$$Emissions = Grand\ total\ CH_4\ emissions * \frac{1 - C_{CH4,PG} - C_{CO2,PG} - C_{N2,PG} - C_{H2S,PG}}{C_{CH4,PG}} * \frac{M_{NMVOC}}{V} * N$$

Where:

Grand total CH_4 emissions = Result from Equation 32
$C_{CO2,PG}$ = CO_2 content of process gas (defined in template)
$C_{CH4,PG}$ = CH_4 content of process gas (defined in template)
M_{NMVOC} = Molecular weight of NMVOC (defined in template)
V = Standard volume (defined in template)
N = Unit conversion factor (defined in template)

Pneumatic controllers

Equation 35: Calculate emissions of CH4 from pneumatic controllers when measured contributions input is available:

$$Emissions = K * N$$

Where:

K = Measured contribution (from user input)
N = Unit conversion factor (defined in template based on user input, if necessary)

Equation 36: Calculate emissions of CH4 from pneumatic controllers when measured contributions input is not available:

$$Grand\ total\ emissions = \sum_{1}^{20} \left(Q * X_C * E * C_{CH4,SG} * T_O\right)_n$$

Where:

Q = Quantity (from user input)
X_C = Component count (defined in template)
E = Emission factor (defined in template)
T_O = Operating time as a percentage (from user input)
$C_{CH4,SG}$ = CH_4 content of pneumatic supply gas (defined in template)
n = Category 1 through 20

Equation 37: Calculate emissions of CO2 from pneumatic controllers:

$$Emissions = Grand\ total\ methane\ emissions * \frac{C_{CO2,SG}}{C_{CH4,SG}}$$

Where:

Grand total methane emissions = Result from Equation 36
$C_{CO2,SG}$ = CO_2 content of pneumatic supply gas (defined in template)
$C_{CH4,SG}$ = CH_4 content of pneumatic supply gas (defined in template)

Equation 38: Calculate emissions of NMVOC from pneumatic controllers:

$$Emissions = Grand\ total\ CH_4\ emissions * (1 - C_{CH4,SG} - C_{CO2,SG} - C_{N2,SG} - C_{H2S,SG})/C_{CH4,SG}$$

Where:

Grand total CH_4 emissions = Result from Equation 36
$C_{CO2,SG}$ = CO_2 content of pneumatic supply gas (defined in template)
$C_{CH4,SG}$ = CH_4 content of pneumatic supply gas (defined in template)
$C_{N2,SG}$ = N_2 content of pneumatic supply gas (defined in template)
$C_{H2S,SG}$ = H_2S content of pneumatic supply gas (defined in template)

Pneumatic Chemical Injection Pumps

Equation 39: Calculate emissions of CH4 from pneumatic chemical injection pumps where measured contributions input is available:

$$Emissions = K * N$$

Where:

K = Measured contribution (from user input)
N = Unit conversion factor (defined in template based on user input, if necessary)

Equation 40: Calculate emissions of CH4 from pneumatic chemical injection pumps where measured contributions input is not available:

$$Grand\ total\ emissions = \sum_{1}^{3} \left(X_E * E * C_{CH4,SG} * T_O \right)_n$$

Where:

X_E = Equipment count per source type (from user input)
E = Emission factor per source type (defined in template)
$C_{CH4,SG}$ = CH_4 content of pneumatic supply gas (defined in template)
T_O = Operating time as percentage per source type (defined in template)
n = Source type 1 through 3

Equation 41: Calculate emissions of CO2 from pneumatic chemical injection pumps:

$$Emissions = Grand\ total\ methane\ emissions * \frac{C_{CO2,SG}}{C_{CH4,SG}}$$

Where:

Grand total methane emissions = Result from Equation 40
$C_{CO2,SG}$ = CO_2 content of pneumatic supply gas (defined in template)
$C_{CH4,SG}$ = CH_4 content of pneumatic supply gas (defined in template)

Equation 42: Calculate emissions of NMVOC from pneumatic chemical injection pumps:

$$Emissions = Grand\ total\ CH_4\ emissions * (1 - C_{CH4,SG} - C_{CO2,SG} - C_{N2,SG} - C_{H2S,SG})/C_{CH4,SG}$$

Where:

Grand total CH_4 emissions = Result from Equation 40
$C_{CO2,SG}$ = CO_2 content of pneumatic supply gas (defined in template)
$C_{CH4,SG}$ = CH_4 content of pneumatic supply gas (defined in template)
$C_{N2,SG}$ = N_2 content of pneumatic supply gas (defined in template)
$C_{H2S,SG}$ = H_2S content of pneumatic supply gas (defined in template)

Pressure vessels

Equation 43: Calculate emissions of CH4 from pressure vessels:

$$Grand\ total\ emissions = \sum_{1}^{20} (X_C * Q * E * N)_n$$

Where:

X_C = Component count per category (from user input)
Q = Quantity per category (from user input)
E = Emission factor per category (defined in template)
N = Conversion factor per category (defined in template)
n = Category 1 through 20

Equation 44: Calculate emissions of CO2 from pressure vessels*:*

$$Emissions = Grand\ total\ CH_4\ emissions * \frac{C_{CO2,PG}}{C_{CH4,PG}}$$

Where:

Grand total CH_4 emissions = Result from Equation 43
$C_{CO2,PG}$ = CO_2 content of process gas (defined in template)
$C_{CH4,PG}$ = CH_4 content of process gas (defined in template)

Equation 45: Calculate emissions of NMVOC from pressure vessels:

$$Emissions = Grand\ total\ CH_4\ emissions * (1 - C_{CH4,PG} - C_{CO2,PG} - C_{N2,PG} - C_{H2S,PG})/C_{CH4,PG}$$

Where:

Grand total CH_4 emissions = Result from Equation 43
$C_{CO2,PG}$ = CO_2 content of process gas (defined in template)
$C_{CH4,PG}$ = CH_4 content of process gas (defined in template)
$C_{N2,PG}$ = N_2 content of process gas (defined in template)
$C_{H2S,PG}$ = H_2S content of process gas (defined in template)

Compressor starts

Equation 46: Calculate emissions of CH4 from compressor starts:

$$Emissions = \left(\sum_{1}^{4} X_n * E_n\right) * C_{CH4,FG} * N$$

Where:

X = Component count per source type (from user input)
E = Emission factor per source type (defined in template)
$C_{CH4,FG}$ = CH_4 content of fuel gas (defined in template)
N = Unit conversion factor (defined in template)
n = Source type 1 through 4

Equation 47: Calculate emissions of CO2 from compressor starts:

$$Emissions = Grand\ total\ CH_4\ emissions * \frac{C_{CO2,CG}}{C_{CH4,CG}}$$

Where:

Grand total CH_4 emissions = Result from Equation 46
$C_{CO2,CG}$ = CO_2 content of casinghead vent gas (defined in template)
$C_{CH4,CG}$ = CH_4 content of casinghead vent gas (defined in template)
M_{CO2} = Molecular weight of CO_2 (defined in template)
V = Standard volume (defined in template)
N = Unit conversion factor (defined in template)

Equation 48: Calculate emissions of NMVOC from compressor starts:

$$Emissions = Grand\ total\ CH_4\ emissions * (1 - C_{CH4,PG} - C_{CO2,PG} - C_{N2,PG} - C_{H2S,PG})/C_{CH4,PG}$$

Where:

Grand total CH_4 emissions = Result from Equation 46
$C_{CO2,CG}$ = CO_2 content of casinghead vent gas (defined in template)
$C_{CH4,CG}$ = CH_4 content of casinghead vent gas (defined in template)
M_{NMVOC} = Molecular weight of NMVOC (defined in template)
V = Standard volume (defined in template)
N = Unit conversion factor (defined in template)

Dehydrators

Equation 49: Calculate emissions of CH4 from dehydrators where measured contributions input is available:

$$Emissions = K * N$$

Where:

K = Measured contribution (from user input)
N = Unit conversion factor (defined in template based in user input, if necessary)

Equation 50: Calculate emissions of CH4 from dehydrators where measured contributions input is not available:

$$Emissions = \sum_{1}^{2} \left(G * E * C_{CH4,PG}\right)_n$$

Where:

G = Amount of gas processed (from user input)
E = Emission factor (defined in template)
C_{CH4} = CH_4 content of process gas (defined in template)
n = Type of dehydrator 1 through 2

Equation 51: Calculate emissions of CO2 from dehydrators:

$$Emissions = Grand\ total\ CH_4\ emissions * \frac{C_{CO2,PG}}{C_{CH4,PG}}$$

Where:

Grand total CH_4 emissions = Result from Equation 50
$C_{CO2,PG}$ = CO_2 content of process gas (defined in template)
$C_{CH4,PG}$ = CH_4 content of process gas (defined in template)

Equation 52: Calculate emissions of NMVOC from dehydrators:

$$Emissions = Grand\ total\ CH_4\ emissions * (1 - C_{CH4,PG} - C_{CO2,PG} - C_{N2,PG} - C_{H2S,PG})/C_{CH4,PG}$$

Where:

Grand total CH_4 emissions = Result from Equation 50
$C_{CO2,PG}$ = CO_2 content of process gas (defined in template)
$C_{CH4,PG}$ = CH_4 content of process gas (defined in template)
$C_{N2,PG}$ = N_2 content of process gas (defined in template)
$C_{H2S,PG}$ = H_2S content of process gas (defined in template)

Sweetening units

Equation 53: Calculate emissions of CH4 from sweetening units where measured contributions input is available:

$$Emissions = K * N$$

Where:

K = Measured contribution (from user input)
N = Unit conversion factor (defined in template based in user input, if necessary)

Equation 54: Calculate emissions of CH4 from sweetening units where measured contributions input is not available:

$$Emissions = G * E * N$$

Where:

G = Amount of gas processed (from user input)
E = Emission factor (defined in template)
N = Unit conversion for emission factor (defined in template)

Equation 55: Calculate emissions of CO2 from sweetening units:

$$Emissions = Grand\ total\ CH_4\ emissions * \frac{C_{CO2,AG}}{C_{CH4,AG}}$$

Where:

Grand total CH_4 emissions = Result from Equation 54
$C_{CO2,AG}$ = CO_2 content of vented acid gas (defined in template)
$C_{CH4,AG}$ = CH_4 content of vented acid gas (defined in template)

Equation 56: Calculate emissions of NMVOC from sweetening units:

$$Emissions = Grand\ total\ CH_4\ emissions * (1 - C_{CH4,AG} - C_{CO2,AG} - C_{N2,AG} - C_{H2S,AG})/C_{CH4,AG}$$

Where:

Grand total CH_4 emissions = Result from Equation 54
$C_{CO2,PG}$ = CO_2 content of vented acid gas (defined in template)
$C_{CH4,PG}$ = CH_4 content of vented acid gas (defined in template)
$C_{N2,PG}$ = N_2 content of vented acid gas (defined in template)
$C_{H2S,PG}$ = H_2S content of vented acid gas (defined in template)

Storage losses

Equation 57: Calculate emissions of CH4 from storage losses:

$$Emissions = Y * C_{CH4,V}$$

Where:

Y = Flashing losses (from user input)
$C_{CH4,V}$ = CH_4 content of product vapors (defined in template)

Equation 58: Calculate emissions of CO2 from storage losses:

$$Emissions = Grand\ total\ CH_4\ emissions * \frac{C_{CO2,PV}}{C_{CH4,PV}}$$

Where:

Grand total CH_4 emissions = Result from Equation 57
$C_{CO2,PG}$ = CO_2 content of product vapors (defined in template)
$C_{CH4,PG}$ = CH_4 content of product vapors (defined in template)

Equation 59: Calculate emissions of NMVOC from storage losses:

$$Emissions = Grand\ total\ CH_4\ emissions * (1 - C_{CH4,PV} - C_{CO2,PV} - C_{N2,PV} - C_{H2S,PV})/C_{CH4,PV}$$

Where:

Grand total CH_4 emissions = Result from Equation 57
$C_{CO2,PG}$ = CO_2 content of product vapors (defined in template)
$C_{CH4,PG}$ = CH_4 content of product vapors (defined in template)
$C_{N2,PG}$ = N_2 content of product vapors (defined in template)
$C_{H2S,PG}$ = H_2S content of product vapors (defined in template)

Mishaps

Equation 60: Calculate emissions of CH4 from mishaps:

$$Emissions = G * E * C_{CH4,PG}$$

Where:

G = Amount of gas processed (from user input)
E = Emission factor (defined in template)
$C_{CH4,PG}$ = CH_4 content of process gas (defined in template)

Equation 61: Calculate emissions of CO2 from mishaps:

$$Emissions = Grand\ total\ CH_4\ emissions * \frac{C_{CO2,PG}}{C_{CH4,PG}}$$

Where:

Grand total CH_4 emissions = Result from Equation 60
$C_{CO2,PG}$ = CO_2 content of process gas (defined in template)
$C_{CH4,PG}$ = CH_4 content of process gas (defined in template)

Equation 62: Calculate emissions of NMVOC from mishaps:

$$Emissions = Grand\ total\ CH_4\ emissions * (1 - C_{CH4,PG} - C_{CO2,PG} - C_{N2,PG} - C_{H2S,PG})/C_{CH4,PG}$$

Where:

Grand total CH_4 emissions = Result from Equation 60
$C_{CO2,PG}$ = CO_2 content of process gas (defined in template)
$C_{CH4,PG}$ = CH_4 content of process gas (defined in template)
$C_{N2,PG}$ = N_2 content of process gas (defined in template)
$C_{H2S,PG}$ = H_2S content of process gas (defined in template)

Wells

Equation 63: Calculate emissions of CH4 from well casinghead vents:

$$Emissions = \left(\sum_{1}^{4} X_n * D * E_n \right)$$

Where:

X = Component count (from user input)
D = Density of CH_4
E = Emission factor (defined in template)
n = Source type 1 through 4

Equation 64: Calculate emissions of CO2 from well casinghead vents:

$$Emissions = \left(Grand\ total\ CH_4\ emissions * \frac{C_{CO2,CG}}{C_{CH4,CG}} \right) * \left(\frac{M_{CO2}}{V} \right) * N$$

Where:

Grand total CH_4 emissions = Result from Equation 63
$C_{CO2,CG}$ = CO_2 content of casinghead vent gas (defined in template)
$C_{CH4,CG}$ = CH_4 content of casinghead vent gas (defined in template)
M_{CO2} = Molecular weight of CO_2 (defined in template)
V = Standard volume (defined in template)
N = Unit conversion factor (defined in template)

Equation 65: Calculate emissions of NMVOC from well casinghead vents:

$$Emissions = \left(Grand\ total\ CH_4\ emissions * \left((1 - C_{CH4,CG} - C_{CO2,CG} - C_{N2,CG} - C_{H2S,CG}) / C_{CH4,CG} \right) \right) * \frac{M_{NMVOC}}{V} * N$$

Where:

Grand total CH_4 emissions = Result from Equation 63
$C_{CO2,CG}$ = CO_2 content of casinghead vent gas (defined in template)
$C_{CH4,CG}$ = CH_4 content of casinghead vent gas (defined in template)
M_{NMVOC} = Molecular weight of NMVOC (defined in template)
V = Standard volume (defined in template)
N = Unit conversion factor (defined in template)

Other

Equation 66: Calculate emissions of CH4 from other direct measurements:

$$Emissions = \left(\sum_{1}^{4} K_n * D * N\right)$$

Where:

K = Measured contribution (from user input)
D = Density of CH_4
N = Unit conversion factor (defined in template)
n = Source subtype (1 through 4)

Equation 67: Calculate emissions of CO2 from other direct measurements:

$$Emissions = \left(Grand\ total\ CH_4\ emissions * \frac{C_{CO2,CG}}{C_{CH4,CG}}\right) * \left(\frac{M_{CO2}}{V}\right) * N$$

Where:

Grand total CH_4 emissions = Result from Equation 66
$C_{CO2,CG}$ = CO_2 content of casinghead vent gas (defined in template)
$C_{CH4,CG}$ = CH_4 content of casinghead vent gas (defined in template)
M_{CO2} = Molecular weight of CO_2 (defined in template)
V = Standard volume (defined in template)
N = Unit conversion factor (defined in template)

Equation 68: Calculate emissions of NMVOC from other direct measurements:

$$Emissions = \left(Grand\ total\ CH_4\ emissions * \left((1 - C_{CH4,CG} - C_{CO2,CG} - C_{N2,CG} - C_{H2S,CG})/C_{CH4,CG}\right)\right) * \frac{M_{NMVOC}}{V} * N$$

Where:

Grand total CH_4 emissions = above from equation 66
$C_{CO2,CG}$ = CO_2 content of casinghead vent gas (defined in template)
$C_{CH4,CG}$ = CH_4 content of casinghead vent gas (defined in template)
M_{NMVOC} = Molecular weight of NMVOC (defined in template)
V = Standard volume (defined in template)
N = Unit conversion factor (defined in template)

APPENDIX B: "Equipment Schedules" Worksheet Supplementary Tables

Table B-1: Equipment Component Types Analyzed for Leaks

Equipment Component Type	**Service**
Valves	Gas
Valves	Light Liquid
Valves	Heavy Liquid
Valves (Block)	Gas
Valves (Control)	Gas
Pump Seals	Light Liquid
Pump Seals	Heavy Liquid
Compressor Seals (Reciprocating - Operating)	Gas
Compressor Seals (Reciprocating - Standby & Pressurized)	Gas
Compressor Seals (Reciprocating - Depressurized)	Gas
Compressor Wet Seals (Centrifugal - Operating)	Gas
Compressor Wet Seals (Centrifugal - Standby & Pressurized)	Gas
Compressor Wet Seals (Centrifugal - Depressurized)	Gas
Compressor Dry Seals (Centrifugal - Operating)	Gas
Compressor Dry Seals (Centrifugal - Standby & Pressurized)	Gas
Compressor Dry Seals (Centrifugal - Depressurized)	Gas
Compressor (Reciprocating - Crankcase Vent)	Gas
Pressure Relief Valves	Gas
Regulators	Gas
Connectors	Gas
Connectors	Light Liquid
Connectors	Heavy Liquid
Open-ended Lines	Gas
Open-ended Lines	Light Liquid

Open-ended Lines	Heavy Liquid
Sampling Connections	All
Drains	All
Meter (Orifice)	Gas
Meter (Other)	Gas
Blowdown System	Gas
Others	Gas
Others	Light Liquid
Others	Heavy Liquid

<u>**APPENDIX C: “EFs-Other” Worksheet Supplementary Tables**</u>

Table C-1: Emission Factors for Pneumatic Controllers

Industry Segment	**Controller Type**	**Data Source**	**As Reported in Reference**	
			EF Value	**Units of Measure**
Offshore Oil Production	High-Bleed	API Compendium (2021) Table 6-14	37.3	scf/h/device
Offshore Oil Production	Intermittent Bleed	API Compendium (2021) Table 6-15	13.5	scf/h/device
Offshore Oil Production	Low-Bleed	API Compendium (2021) Table 6-14	1.39	scf/h/device
Offshore Oil Production	No-Bleed	None	0	scf/d/device
Offshore Oil Production	Not Applicable	None	0	scf/d/device
Offshore Oil Production	Type Unknown	API Compendium (2021)	9.2	scf/h/device
Offshore Gas Production	High-Bleed	API Compendium (2021) Table 6-14	37.3	scf/h/device
Offshore Gas Production	Intermittent Bleed	API Compendium (2021) Table 6-15	13.5	scf/h/device
Offshore Gas Production	Low-Bleed	API Compendium (2021) Table 6-14	1.39	scf/h/device
Offshore Gas Production	No-Bleed	None	0	scf/d/device
Offshore Gas Production	Not Applicable	None	0	scf/d/device
Offshore Gas Production	Type Unknown	API Compendium (2021)	9.2	scf/h/device

Onshore Oil Production	High-Bleed	API Compendium (2021) Table 6-14	37.3	scf/h/device
Onshore Oil Production	Intermittent Bleed	API Compendium (2021) Table 6-15	13.5	scf/h/device
Onshore Oil Production	Low-Bleed	API Compendium (2021) Table 6-14	1.39	scf/h/device
Onshore Oil Production	No-Bleed	None	0	scf/d/device
Onshore Oil Production	Not Applicable	None	0	scf/d/device
Onshore Oil Production	Type Unknown	API Compendium (2021)	9.2	scf/h/device
Onshore Gas Production	High-Bleed	API Compendium (2021) Table 6-14	37.3	scf/h/device
Onshore Gas Production	Intermittent Bleed	API Compendium (2021) Table 6-15	13.5	scf/h/device
Onshore Gas Production	Low-Bleed	API Compendium (2021) Table 6-14	1.39	scf/h/device
Onshore Gas Production	No-Bleed	None	0	scf/d/device
Onshore Gas Production	Not Applicable	None	0	scf/d/device
Onshore Gas Production	Type Unknown	API Compendium (2021)	9.2	scf/h/device
Gas Processing	High-Bleed	US EPA Subpart W RY 2014	407	scfd/device
Gas Processing	Intermittent Bleed	US EPA Subpart W RY 2014	53	scfd/device
Gas Processing	Low-Bleed	US EPA Subpart W RY 2014	30.4	scfd/device
Gas Processing	No-Bleed	None	0	scfd/device

Gas Processing	Not Applicable	None	0	scfd/device
Gas Transmission	High-Bleed	US EPA Subpart W RY 2014	407	scfd/device
Gas Transmission	Intermittent Bleed	US EPA Subpart W RY 2014	53	scfd/device
Gas Transmission	Low-Bleed	US EPA Subpart W RY 2014	30.4	scfd/device
Gas Transmission	No-Bleed	None	0	scfd/device
Gas Transmission	Not Applicable	None	0	scfd/device
Gas Storage	High-Bleed	US EPA Subpart W RY 2014	407	scfd/device
Gas Storage	Intermittent Bleed	US EPA Subpart W RY 2014	53	scfd/device
Gas Storage	Low-Bleed	US EPA Subpart W RY 2014	30.4	scfd/device
Gas Storage	No-Bleed	None	0	scfd/device
Gas Storage	Not Applicable	None	0	scfd/device
Gas Distribution	High-Bleed	US EPA Subpart W RY 2014	407	scfd/device
Gas Distribution	Intermittent Bleed	US EPA Subpart W RY 2014	53	scfd/device
Gas Distribution	Low-Bleed	US EPA Subpart W RY 2014	30.4	scfd/device
Gas Distribution	No-Bleed	None	0	scfd/device
Gas Distribution	Not Applicable	None	0	scfd/device
Petroleum Refining	High-Bleed	US EPA Subpart W RY 2014	407	scfd/device

Petroleum Refining	Intermittent Bleed	US EPA Subpart W RY 2014	53	scfd/device
Petroleum Refining	Low-Bleed	US EPA Subpart W RY 2014	30.4	scfd/device
Petroleum Refining	No-Bleed	None	0	scfd/device
Petroleum Refining	Not Applicable	None	0	scfd/device

Table C-2: Emission Factors for Pneumatic Chemical Injection Pumps

Industry Segment	**Subcategory**	**Data Source**	**As Reported in the Reference**		
			EF Value	**Units of Measure**	**CH4 Content Basis for Industry Segment (Mol%)**
Offshore Oil Production	Diaphragm pumps	API Compendium (2021) Table 6-16	895.2	scf/d/pump	78.8
Offshore Oil Production	Piston pumps	API Compendium (2021) Table 6-16	501.6	scf/d/pump	78.8
Offshore Oil Production	Average pump (if type unknown)	API Compendium (2021) Table 6-16	825.6	scf/d/pump	78.8
Offshore Gas Production	Diaphragm pumps	API Compendium (2021) Table 6-16	895.2	scf/d/pump	78.8
Offshore Gas Production	Piston pumps	API Compendium (2021) Table 6-16	501.6	scf/d/pump	78.8
Offshore Gas Production	Average pump (if type unknown)	API Compendium (2021) Table 6-16	825.6	scf/d/pump	78.8
Onshore Oil Production	Diaphragm pumps	API Compendium (2021) Table 6-16	895.2	scf/d/pump	78.8
Onshore Oil Production	Piston pumps	API Compendium (2021) Table 6-16	501.6	scf/d/pump	78.8

Onshore Oil Production	Average pump (if type unknown)	API Compendium (2021) Table 6-16	825.6	scf/d/pump	78.8
Onshore Gas Production	Diaphragm pumps	API Compendium (2021) Table 6-16	895.2	scf/d/pump	78.8
Onshore Gas Production	Piston pumps	API Compendium (2021) Table 6-16	501.6	scf/d/pump	78.8
Onshore Gas Production	Average pump (if type unknown)	API Compendium (2021) Table 6-16	825.6	scf/d/pump	78.8
Gas Processing	Diaphragm pumps	API Compendium (2021) Table 6-16	895.2	scf/d/pump	78.8
Gas Processing	Piston pumps	API Compendium (2021) Table 6-16	501.6	scf/d/pump	78.8
Gas Processing	Average pump (if type unknown)	API Compendium (2021) Table 6-16	825.6	scf/d/pump	78.8
Gas Transmission	Diaphragm pumps	API Compendium (2021) Table 6-16	895.2	scf/d/pump	78.8
Gas Transmission	Piston pumps	API Compendium (2021) Table 6-16	501.6	scf/d/pump	78.8
Gas Transmission	Average pump (if type unknown)	API Compendium (2021) Table 6-16	825.6	scf/d/pump	78.8
Gas Storage	Diaphragm pumps	API Compendium (2021) Table 6-16	895.2	scf/d/pump	78.8
Gas Storage	Piston pumps	API Compendium (2021) Table 6-16	501.6	scf/d/pump	78.8
Gas Storage	Average pump (if type unknown)	API Compendium (2021) Table 6-16	825.6	scf/d/pump	78.8
Gas Distribution	Diaphragm pumps	API Compendium (2021) Table 6-16	895.2	scf/d/pump	78.8
Gas Distribution	Piston pumps	API Compendium (2021) Table 6-16	501.6	scf/d/pump	78.8
Gas Distribution	Average pump (if type unknown)	API Compendium (2021) Table 6-16	825.6	scf/d/pump	78.8

Petroleum Refining	Diaphragm pumps	API Compendium (2021) Table 6-16	895.2	scf/d/pump	78.8
Petroleum Refining	Piston pumps	API Compendium (2021) Table 6-16	501.6	scf/d/pump	78.8
Petroleum Refining	Average pump (if type unknown)	API Compendium (2021) Table 6-16	825.6	scf/d/pump	78.8

Table C-3: Emission Factors for Dehydrators

Industry Segment	**Subcategory**	**Data Source**	**As Reported in the Reference**		
			EF Value	**Units of Measure**	**CH4 Content Basis for Industry Segment (Mol %)**
Offshore Oil Production	With Gas-Assisted Pump Emissions	API Compendium (2021) Table 6-18	992	scf/10^6 scf gas processed	78.8
Offshore Oil Production	Without Gas-Assisted Pump Emissions	API Compendium (2021) Table 6-17	275.57	scf/10^6 scf gas processed	78.8
Offshore Gas Production	With Gas-Assisted Pump Emissions	API Compendium (2021) Table 6-18	992	scf/10^6 scf gas processed	78.8
Offshore Gas Production	Without Gas-Assisted Pump Emissions	API Compendium (2021) Table 6-17	275.57	scf/10^6 scf gas processed	78.8
Onshore Oil Production	With Gas-Assisted Pump Emissions	API Compendium (2021) Table 6-18	992	scf/10^6 scf gas processed	78.8
Onshore Oil Production	Without Gas-Assisted Pump Emissions	API Compendium (2021) Table 6-17	275.57	scf/10^6 scf gas processed	78.8
Onshore Gas Production	With Gas-Assisted Pump Emissions	API Compendium (2021) Table 6-18	992	scf/10^6 scf gas processed	78.8
Onshore Gas Production	Without Gas-Assisted Pump Emissions	API Compendium (2021) Table 6-17	275.57	scf/10^6 scf gas processed	78.8
Gas Processing	With Gas-Assisted Pump Emissions	API Compendium (2021) Table 6-36	177.75	scf/10^6 scf gas processed	86.8

Gas Processing	Without Gas-Assisted Pump Emissions	API Compendium (2021) Table 6-35	121.55	scf/10^6 scf gas processed	86.8
Gas Transmission	With Gas-Assisted Pump Emissions	Adopted from API Compendium (2021) Table 6-36	177.75	scf/10^6 scf gas processed	86.8
Gas Transmission	Without Gas-Assisted Pump Emissions	Adopted from API Compendium (2021) Table 6-35	121.55	scf/10^6 scf gas processed	86.8
Gas Storage	With Gas-Assisted Pump Emissions	Adopted from API Compendium (2021) Table 6-36	177.75	scf/10^6 scf gas processed	86.8
Gas Storage	Without Gas-Assisted Pump Emissions	Adopted from API Compendium (2021) Table 6-35	121.55	scf/10^6 scf gas processed	86.8
Gas Distribution	With Gas-Assisted Pump Emissions	Adopted from API Compendium (2021) Table 6-36	177.75	scf/10^6 scf gas processed	86.8
Gas Distribution	Without Gas-Assisted Pump Emissions	Adopted from API Compendium (2021) Table 6-35	121.55	scf/10^6 scf gas processed	86.8
Petroleum Refining	With Gas-Assisted Pump Emissions	Adopted from API Compendium (2021) Table 6-36	177.75	scf/10^6 scf gas processed	86.8
Petroleum Refining	Without Gas-Assisted Pump Emissions	Adopted from API Compendium (2021) Table 6-35	121.55	scf/10^6 scf gas processed	86.8

Table C-4: Emission Factors for Gas Sweetening Units

Industry Segment	Subcategory	Data Source	As Reported in the Reference		
			EF Value	Units of Measure	CH4 Content Basis for Industry Segment (Mol%)
All	All	API Compendium (2021) Table 6-19	965	scf/10^6 scf gas processed	Not Applicable

Table C-5: Emission Factors for Storage Tanks

Industry Segment	Subcategory	Data Source	As Reported in the Reference		
			EF Value	Units of Measure	CH4 Content Basis for Industry Segment (Mol %)
Offshore Oil Production	Crude Oil (Without Control)	API Compendium (2021) Table 6-22	5.57E-03	tonnes/m^3 of crude oil	78.8
Offshore Oil Production	Crude Oil (Large Tanks Without Control)	API Compendium (2021) Table 6-22	1.21E-03	tonnes/m^3 of crude oil	81.6
Offshore Oil Production	Crude Oil (Large Tanks with VRU)	API Compendium (2021) Table 6-22	1.78E-04	tonnes/m^3 of crude oil	81.6
Offshore Oil Production	Crude Oil (Large Tanks with Flares)	API Compendium (2021) Table 6-22	3.30E-05	tonnes/m^3 of crude oil	81.6
Offshore Oil Production	Crude Oil (Small Tanks Without Control)	API Compendium (2021) Table 6-22	1.15E-04	tonnes/m^3 of crude oil	81.6
Offshore Oil Production	Crude Oil (Small Tanks with Flares)	API Compendium (2021) Table 6-22	1.29E-05	tonnes/m^3 of crude oil	81.6
Offshore Oil Production	Condensate (Large Tanks Without Control)	API Compendium (2021) Table 6-24	9.17E-04	tonnes/m^3 of condensate	81.6
Offshore Oil Production	Condensate (Large Tanks with VRU)	API Compendium (2021) Table 6-24	4.19E-05	tonnes/m^3 of condensate	81.6

Offshore Oil Production	Condensate (Large Tanks with Flares)	API Compendium (2021) Table 6-24	3.64E-05	tonnes/m^3 of condensate	81.6
Offshore Oil Production	Condensate (Small Tanks without Flares)	API Compendium (2021) Table 6-24	7.49E-04	tonnes/m^3 of condensate	81.6
Offshore Oil Production	Condensate (Small Tanks with Flares)	API Compendium (2021) Table 6-24	5.73E-06	tonnes/m^3 of condensate	81.6
Offshore Oil Production	Condensate (Without Control)	API Compendium (2021) Table 6-24	1.45E-02	tonnes/m^3 of condensate	81.6
Offshore Oil Production	Produced Water	API Compendium (2021) Table 6-26	1.50E-03	tonnes CH_4/1000 bbl produced water	81.6
Offshore Gas Production	Crude Oil (Without Control)	API Compendium (2021) Table 6-22	5.57E-03	tonnes/m^3 of crude oil	78.8
Offshore Gas Production	Crude Oil (Large Tanks Without Control)	API Compendium (2021) Table 6-22	1.21E-03	tonnes/m^3 of crude oil	81.6
Offshore Gas Production	Crude Oil (Large Tanks with VRU)	API Compendium (2021) Table 6-22	1.78E-04	tonnes/m^3 of crude oil	81.6
Offshore Gas Production	Crude Oil (Large Tanks with Flares)	API Compendium (2021) Table 6-22	3.30E-05	tonnes/m^3 of crude oil	81.6
Offshore Gas Production	Crude Oil (Small Tanks Without Control)	API Compendium (2021) Table 6-22	1.15E-04	tonnes/m^3 of crude oil	81.6
Offshore Gas Production	Crude Oil (Small Tanks with Flares)	API Compendium (2021) Table 6-22	1.29E-05	tonnes/m^3 of crude oil	81.6
Offshore Gas Production	Condensate (Large Tanks Without Control)	API Compendium (2021) Table 6-24	9.17E-04	tonnes/m^3 of condensate	81.6
Offshore Gas Production	Condensate (Large Tanks with VRU)	API Compendium (2021) Table 6-24	4.19E-05	tonnes/m^3 of condensate	81.6
Offshore Gas Production	Condensate (Large Tanks with Flares)	API Compendium (2021) Table 6-24	3.64E-05	tonnes/m^3 of condensate	81.6
Offshore Gas Production	Condensate (Small Tanks without Flares)	API Compendium (2021) Table 6-24	7.49E-04	tonnes/m^3 of condensate	81.6
Offshore Gas Production	Condensate (Small Tanks with Flares)	API Compendium (2021) Table 6-24	5.73E-06	tonnes/m^3 of condensate	81.6

Offshore Gas Production	Condensate (Without Control)	API Compendium (2021) Table 6-24	1.45E-02	tonnes/m^3 of condensate	81.6
Offshore Gas Production	Produced Water	API Compendium (2021) Table 6-26	1.50E-03	tonnes CH4/1000 bbl produced water	81.6
Onshore Oil Production	Crude Oil (Without Control)	API Compendium (2021) Table 6-22	5.57E-03	tonnes/m^3 of crude oil	78.8
Onshore Oil Production	Crude Oil (Large Tanks Without Control)	API Compendium (2021) Table 6-22	1.21E-03	tonnes/m^3 of crude oil	81.6
Onshore Oil Production	Crude Oil (Large Tanks with VRU)	API Compendium (2021) Table 6-22	1.78E-04	tonnes/m^3 of crude oil	81.6
Onshore Oil Production	Crude Oil (Large Tanks with Flares)	API Compendium (2021) Table 6-22	3.30E-05	tonnes/m^3 of crude oil	81.6
Onshore Oil Production	Crude Oil (Small Tanks Without Control)	API Compendium (2021) Table 6-22	1.15E-04	tonnes/m^3 of crude oil	81.6
Onshore Oil Production	Crude Oil (Small Tanks with Flares)	API Compendium (2021) Table 6-22	1.29E-05	tonnes/m^3 of crude oil	81.6
Onshore Oil Production	Condensate (Large Tanks Without Control)	API Compendium (2021) Table 6-24	9.17E-04	tonnes/m^3 of condensate	81.6
Onshore Oil Production	Condensate (Large Tanks with VRU)	API Compendium (2021) Table 6-24	4.19E-05	tonnes/m^3 of condensate	81.6
Onshore Oil Production	Condensate (Large Tanks with Flares)	API Compendium (2021) Table 6-24	3.64E-05	tonnes/m^3 of condensate	81.6
Onshore Oil Production	Condensate (Small Tanks without Flares)	API Compendium (2021) Table 6-24	7.49E-04	tonnes/m^3 of condensate	81.6
Onshore Oil Production	Condensate (Small Tanks with Flares)	API Compendium (2021) Table 6-24	5.73E-06	tonnes/m^3 of condensate	81.6
Onshore Oil Production	Condensate (Without Control)	API Compendium (2021) Table 6-24	1.45E-02	tonnes/m^3 of condensate	81.6
Onshore Oil Production	Produced Water	API Compendium (2021) Table 6-26	1.50E-03	tonnes CH4/1000 bbl produced water	81.6
Onshore Gas Production	Crude Oil (Without Control)	API Compendium (2021) Table 6-22	5.57E-03	tonnes/m^3 of crude oil	78.8

Onshore Gas Production	Crude Oil (Large Tanks Without Control)	API Compendium (2021) Table 6-22	1.21E-03	tonnes/m^3 of crude oil	81.6
Onshore Gas Production	Crude Oil (Large Tanks with VRU)	API Compendium (2021) Table 6-22	1.78E-04	tonnes/m^3 of crude oil	81.6
Onshore Gas Production	Crude Oil (Large Tanks with Flares)	API Compendium (2021) Table 6-22	3.30E-05	tonnes/m^3 of crude oil	81.6
Onshore Gas Production	Crude Oil (Small Tanks Without Control)	API Compendium (2021) Table 6-22	1.15E-04	tonnes/m^3 of crude oil	81.6
Onshore Gas Production	Crude Oil (Small Tanks with Flares)	API Compendium (2021) Table 6-22	1.29E-05	tonnes/m^3 of crude oil	81.6
Onshore Gas Production	Condensate (Large Tanks Without Control)	API Compendium (2021) Table 6-24	9.17E-04	tonnes/m^3 of condensate	81.6
Onshore Gas Production	Condensate (Large Tanks with VRU)	API Compendium (2021) Table 6-24	4.19E-05	tonnes/m^3 of condensate	81.6
Onshore Gas Production	Condensate (Large Tanks with Flares)	API Compendium (2021) Table 6-24	3.64E-05	tonnes/m^3 of condensate	81.6
Onshore Gas Production	Condensate (Small Tanks without Flares)	API Compendium (2021) Table 6-24	7.49E-04	tonnes/m^3 of condensate	81.6
Onshore Gas Production	Condensate (Small Tanks with Flares)	API Compendium (2021) Table 6-24	5.73E-06	tonnes/m^3 of condensate	81.6
Onshore Gas Production	Condensate (Without Control)	API Compendium (2021) Table 6-24	1.45E-02	tonnes/m^3 of condensate	81.6
Onshore Gas Production	Produced Water	API Compendium (2021) Table 6-26	1.50E-03	tonnes CH4/1000 bbl produced water	81.6
Gas Processing	Chemicals (Fixed - Roof Tank with Natural Gas Blanketing)	Adapted from API	9.17E-04	tonnes/m^3 of condensate	81.6
Gas Processing	Condensate (External Floating - Roof Tank)	Adapted from API	4.19E-05	tonnes/m^3 of condensate	81.6
Gas Processing	Condensate (Fixed - Roof Tank with Vapor Control)	Assumed	0.00E+00	tonnes/m^3 of condensate	81.6

Gas Processing	Condensate (Fixed - Roof Tank without Vapor Control)	Assumed	0.00E+00	tonnes/m^3 of condensate	81.6
Gas Processing	Condensate (Internal Floating - Roof Tank))	Adapted from API	1.50E-03	tonnes CH4/1000 bbl produced water	81.6
Gas Processing	Produced Water (External Floating - Roof Tank)	Assumed	0.00E+00	tonnes CH4/1000 bbl produced water	81.6
Gas Processing	Produced Water (Fixed - Roof Tank with Vapor Control)	Assumed	0.00E+00	tonnes CH4/1000 bbl produced water	81.6
Gas Processing	Produced Water (Fixed - Roof Tank without Vapor Control)	Assumed	0.00E+00	tonnes CH4/1000 bbl produced water	81.6
Gas Processing	Produced Water (Internal Floating - Roof Tank)	Assumed	0.00E+00	tonnes/m^3 of crude oil	81.6
Gas Transmission	Condensate	Assumed	0.00E+00	tonnes/m^3 of condensate	81.6
Gas Storage	Condensate	Assumed	0.00E+00	tonnes/m^3 of condensate	81.6
Gas Distribution	Condensate	Assumed	0.00E+00	tonnes/m^3 of condensate	81.6
Petroleum Refining	Crude Oil	Assumed	0.00E+00	tonnes/m^3 of condensate	81.6

Table C-6: Emission Factors for Oil Well Casing Vents

Industry Segment	**Well Type**	**Data Source**	**As Reported in the Reference**		
			EF Value	**Units of Measure**	**CH4 Content Basis for Industry Segment (Mol%)**
Onshore Oil Production	Cold Heavy Oil (Active)	API Compendium (2021) Table 6-12	3.28E+00	tonnes/1000 bbl oil produced	81.6
Onshore Oil Production	Cold Heavy Oil (Inactive)	Not Avialble	0.0	tonnes/1000 bbl oil produced	81.6
Onshore Oil Production	Thermal Heavy Oil	API Compendium (2021) Table 6-12	2.23E-01	tonnes/1000 bbl oil produced	81.6
Onshore Oil Production	Crude Bitumen	API Compendium (2021) Table 6-12	2.07E-01	tonnes/1000 bbl oil produced	81.6

Table C-7: Emission Factors for Wellhead Casing Vents

Industry Segment	**Well Type**	**Data Source**	**As Reported in the Reference**		
			EF Value	**Units of Measure**	**CH4 Content Basis for Industry Segment (Mol%)**
Onshore Oil Production	Low-Pressure Gas	API Compendium (2021) Page 6-31	2.13E-03	tonnes CH4/d/well	81.6
Onshore Oil Production	Conventional Crude Oil Wells	Not Available	0.00E+00	tonnes CH4/d/well	81.6
Onshore Oil Production	Cold Heavy Oil (Active)	API Compendium (2021) Table 6-13	2.05E-02	tonnes CH4/d/well	81.6
Onshore Oil Production	Cold Heavy Oil (Suspended)	API Compendium (2021) Table 6-14	1.11E-02	tonnes CH4/d/well	81.6
Onshore Oil Production	Crude Bitumen (Active)	API Compendium (2021) Table 6-15	2.05E-02	tonnes CH4/d/well	81.6

Onshore Oil Production	Crude Bitumen (Suspended)	API Compendium (2021) Table 6-16	1.11E-02	tonnes CH4/d/well	81.6

Table C-8: Emission Factors for Inspection and Maintenance Activities

Industry Segment	Activity	Uncontrolled Emissions Factor	Data Source	As Reported in the Reference		
		Units of Measure		CH4 EF Value	Units of Measure	CH4 Content
						Basis for Industry Segment (Mol%)
Offshore Oil Production	Vessel Blowdowns	m3/y/vessel	API Compendium (2021) Table 6-32	7.80E+01	scf CH4/y/vessel	78.8
Offshore Oil Production	Compressor Starts	m3/y/compressor	API Compendium (2021) Table 6-33	8.44E+03	scf CH4/y/compressor	78.8
Offshore Oil Production	Compressor Blowdowns	m3/y/compressor	API Compendium (2021) Table 6-32	3.77E+03	scf CH4/y/compressor	78.8
Offshore Oil Production	Gas Well Workover (Tubing Maintenance)	m3/workover	API Compendium (2021) Table 6-9	2.45E+03	scf CH4/workover	78.8
Offshore Oil Production	Oil Well Workover (Tubing Maintenance)	m3/workover	API Compendium (2021) Table 6-9	9.60E+01	scf CH4/workover	78.8
Offshore Oil Production	Gathering Gas Pipeline Blowdowns	m3/y/km of Gas Gathering Pipeline	Adopted from API Compendium	3.09E+02	scf CH4/y/mile of Gas Gathering Pipeline	78.8

			(2021) Table 6-32			
Offshore Oil Production	Gas Well Completions without Hydraulic Fracturing (Vented)	m3/completion-day	API Compendium (2021) Table 6-6	1.74E+03	kg CH4/completion	78.8
Offshore Oil Production	Oil Well Completions without Hydraulic Fracturing (Vented)	m3/completion-day	API Compendium (2021) Table 6-6	1.41E+01	kg CH4/completion	78.8
Offshore Oil Production	Oil Pump Station Maintenance	m3/y/station	API Compendium (2021) Table 6-33	1.56E+00	lb CH4/y/station	78.8
Offshore Oil Production	Offshore Emergency Shutdown	m3/y/station	API Compendium (2021) Table 6-28	2.57E+05	scf CH4/y/platform	78.8
Offshore Gas Production	Vessel Blowdowns	m3/y/vessel	API Compendium (2021) Table 6-32	7.80E+01	scf CH4/y/vessel	78.8
Offshore Gas Production	Compressor Starts	m3/y/compressor	API Compendium (2021) Table 6-33	8.44E+03	scf CH4/y/compressor	78.8
Offshore Gas Production	Compressor Blowdowns	m3/y/compressor	API Compendium (2021) Table 6-32	3.77E+03	scf CH4/y/compressor	78.8
Offshore Gas Production	Gas Well Workover (Tubing Maintenance)	m3/workover	API Compendium (2021) Table 6-9	2.45E+03	scf CH4/workover	78.8

Offshore Gas Production	Oil Well Workover (Tubing Maintenance)	m3/workover	API Compendium (2021) Table 6-9	9.60E+01	scf CH4/workover	78.8
Offshore Gas Production	Gathering Gas Pipeline Blowdowns	m3/y/km of Gas Gathering Pipeline	Adopted from API Compendium (2021) Table 6-32	3.09E+02	scf CH4/y/mile of Gas Gathering Pipeline	78.8
Offshore Gas Production	Gas Well Completions without Hydraulic Fracturing (Vented)	m3/completion-day	API Compendium (2021) Table 6-6	1.74E+03	kg CH4/completion	78.8
Offshore Gas Production	Oil Well Completions without Hydraulic Fracturing (Vented)	m3/completion-day	API Compendium (2021) Table 6-6	1.41E+01	kg CH4/completion	78.8
Onshore Oil Production	Vessel Blowdowns	m3/y/vessel	API Compendium (2021) Table 6-32	7.80E+01	scf CH4/y/vessel	78.8
Onshore Oil Production	Compressor Starts	m3/y/compressor	API Compendium (2021) Table 6-33	8.44E+03	scf CH4/y/compressor	78.8
Onshore Oil Production	Compressor Blowdowns	m3/y/compressor	API Compendium (2021) Table 6-32	3.77E+03	scf CH4/y/compressor	78.8
Onshore Oil Production	Gas Well Workover (Tubing Maintenance)	m3/workover	API Compendium (2021) Table 6-9	2.45E+03	scf CH4/workover	78.8
Onshore Oil Production	Oil Well Workover (Tubing Maintenance)	m3/workover	API Compendium (2021) Table 6-9	9.60E+01	scf CH4/workover	78.8

Onshore Oil Production	Gathering Gas Pipeline Blowdowns	m3/y/km of Gas Gathering Pipeline	API Compendium (2021) Table 6-32	3.09E+02	scf CH4/y/mile of Gas Gathering Pipeline	78.8
Onshore Oil Production	Gas Well Completions without Hydraulic Fracturing (Vented)	m3/completion-day	API Compendium (2021) Table 6-6	1.74E+03	kg CH4/completion	78.8
Onshore Oil Production	Oil Well Completions without Hydraulic Fracturing (Vented)	m3/completion-day	API Compendium (2021) Table 6-6	1.41E+01	kg CH4/completion	78.8
Onshore Oil Production	Oil Pump Station Maintenance	m3/y/station	API Compendium (2021) Table 6-33	1.56E+00	lb CH4/y/station	78.8
Onshore Gas Production	Vessel Blowdowns	m3/y/vessel	API Compendium (2021) Table 6-32	7.80E+01	scf CH4/y/vessel	78.8
Onshore Gas Production	Compressor Starts	m3/y/compressor	API Compendium (2021) Table 6-33	8.44E+03	scf CH4/y/compressor	78.8
Onshore Gas Production	Compressor Blowdowns	m3/y/compressor	API Compendium (2021) Table 6-32	3.77E+03	scf CH4/y/compressor	78.8
Onshore Gas Production	Gas Well Workover (Tubing Maintenance)	m3/workover	API Compendium (2021) Table 6-9	2.45E+03	scf CH4/workover	78.8
Onshore Gas Production	Oil Well Workover (Tubing Maintenance)	m3/workover	API Compendium (2021) Table 6-9	9.60E+01	scf CH4/workover	78.8

Onshore Gas Production	Gathering Gas Pipeline Blowdowns	m3/y/km of Gas Gathering Pipeline	API Compendium (2021) Table 6-32	3.09E+02	scf CH4/y/mile of Gas Gathering Pipeline	78.8
Onshore Gas Production	Gas Well Completions without Hydraulic Fracturing (Vented)	m3/completion-day	API Compendium (2021) Table 6-6	1.74E+03	kg CH4/completion	78.8
Onshore Gas Production	Oil Well Completions without Hydraulic Fracturing (Vented)	m3/completion-day	API Compendium (2021) Table 6-6	1.41E+01	kg CH4/completion	78.8
Onshore Gas Production	Gas Gathering Pipeline Mishaps (Dig-ins)	m3/y/km of Gas Gathering Pipeline	API Compendium (2021) Table 6-33	6.69E+02	scf CH4/y/mile of Gas Gathering Pipeline	78.8
Gas Processing	Vessel Blowdowns	m3/y/vessel	API Compendium (2021) Table 6-32	7.80E+01	scf CH4/y/vessel	78.8
Gas Processing	Compressor Starts	m3/y/compressor	API Compendium (2021) Table 6-33	8.44E+03	scf CH4/y/compressor	78.8
Gas Processing	Compressor Blowdowns	m3/y/compressor	API Compendium (2021) Table 6-32	3.77E+03	scf CH4/y/compressor	78.8
Gas Processing	Gas Well Workover (Tubing Maintenance)	m3/workover	API Compendium (2021) Table 6-9	2.45E+03	scf CH4/workover	78.8
Gas Processing	Oil Well Workover (Tubing Maintenance)	m3/workover	API Compendium (2021) Table 6-9	9.60E+01	scf CH4/workover	78.8

Gas Processing	Gathering Gas Pipeline Blowdowns	m3/y/km of Gas Gathering Pipeline	API Compendium (2021) Table 6-32	3.09E+02	scf CH4/y/mile of Gas Gathering Pipeline	78.8
Gas Processing	Gas Well Completions without Hydraulic Fracturing (Vented)	m3/completion-day	API Compendium (2021) Table 6-6	1.74E+03	kg CH4/completion	78.8
Gas Processing	Oil Well Completions without Hydraulic Fracturing (Vented)	m3/completion-day	API Compendium (2021) Table 6-6	1.41E+01	kg CH4/completion	78.8
Gas Processing	Non-routine Activities	m3/10^6 m3 processed	API Compendium (2021) Table 6-39	1.84E+02	scf CH4/10^6 scf processed	86.8
Gas Transmission	Vessel Blowdowns	m3/y/vessel	Adopted from API Compendium (2021) Table 6-32	7.80E+01	scf CH4/y/vessel	78.8
Gas Transmission	Compressor Starts	m3/y/compressor	Adopted from API Compendium (2021) Table 6-33	8.44E+03	scf CH4/y/compressor	78.8
Gas Transmission	Compressor Blowdowns	m3/y/compressor	Adopted from API Compendium (2021) Table 6-32	3.77E+03	scf CH4/y/compressor	78.8
Gas Transmission	PRV Lifts	m3/y/station	API Compendium (2021) Table 6-43	1.92E+05	scf CH4/y/station	93.4

Gas Transmission	ESD Activations	m3/y/station	API Compendium (2021) Table 6-43	4.15E+05	scf CH4/y/station	93.4
Gas Transmission	Meter and Regulator Station Blowdowns	m3/y/station	API Compendium (2021) Table 6-43	2.00E+04	m3 CH4/y/station	93.4
Gas Transmission	Miscellaneous	m3/y/station	API Compendium (2021) Table 6-43	1.13E+06	scf CH4/y/station	93.4
Gas Transmission	Pipeline Venting & Blowdowns	m3/y/km of Transmission Pipeline	API Compendium (2021) Table 6-43	6.14E-01	tonnes CH4/y/mile	93.4
Gas Storage	Vessel Blowdowns	m3/y/vessel	Adopted from API Compendium (2021) Table 6-32	7.80E+01	scf CH4/y/vessel	78.8
Gas Storage	Compressor Starts	m3/y/compressor	Adopted from API Compendium (2021) Table 6-33	8.44E+03	scf CH4/y/compressor	78.8
Gas Storage	Compressor Blowdowns	m3/y/compressor	Adopted from API Compendium (2021) Table 6-32	3.77E+03	scf CH4/y/compressor	78.8
Gas Storage	Gas Storage Station Venting	m3/y/station	API Compendium	4.30E+01	tonnes CH4/y/station	93.4

			(2021) Table 6-43			
Gas Distribution	Vessel Blowdowns	m3/y/vessel	Adopted from API Compendium (2021) Table 6-32	7.80E+01	scf CH4/y/vessel	78.8
Gas Distribution	Compressor Starts	m3/y/compressor	Adopted from API Compendium (2021) Table 6-33	8.44E+03	scf CH4/y/compressor	78.8
Gas Distribution	Compressor Blowdowns	m3/y/compressor	Adopted from API Compendium (2021) Table 6-32	3.77E+03	scf CH4/y/compressor	78.8
Gas Distribution	Meter & Regulator Station Maintenance	m3/y/station	API Compendium (2021) Table 6-46	4.27E+00	m3 CH4/y/station	94.8
Gas Distribution	Odorizer & Gas Sampling Vents	m3/y/station	API Compendium (2021) Table 6-46	3.36E+01	m3 CH4/y/station	94.8
Gas Distribution	Pipeline Blowdowns	m3/y/km	API Compendium (2021) Table 6-46	1.68E+03	scf CH4/y/mile	93.4
Gas Distribution	Pipeline Mishaps (Dig-ins)	m3/y/km	API Compendium (2021) Table 6-46	1.59E+03	scf CH4/y/mile	93.4

Gas Distribution	PRV Lifts	m3/y/km	API Compendium (2021) Table 6-46	5.00E+01	scf CH4/y/mile	93.4
Petroleum Refining	Vessel Blowdowns	m3/y/vessel	Adopted from API Compendium (2021) Table 6-32	7.80E+01	scf CH4/y/vessel	78.8
Petroleum Refining	Compressor Starts	m3/y/compressor	Adopted from API Compendium (2021) Table 6-33	8.44E+03	scf CH4/y/compressor	78.8
Petroleum Refining	Compressor Blowdowns	m3/y/compressor	Adopted from API Compendium (2021) Table 6-32	3.77E+03	scf CH4/y/compressor	78.8

Table C-9: Emission Factors for Compressors

Industry Segment	**Compressor Type**	**Data Source**	**As Reported in the Reference**		
			EF Value	**Units of Measure**	**CH4 Content Basis for Industry Segment (Mol%)**
Offshore Oil Production	Reciprocating Compressor Rod Packing (Operating Mode)	Adopted from API Compendium (2021) Table 6-37 (Assume 4 seals per compressor)	0.0648	tonnes CH4/compressor-day	87
Offshore Oil Production	Reciprocating Compressor Rod Packing (Standby Mode)	Adopted from API Compendium (2021) Table 6-37 (Assume 4 seals per compressor)	0.0648	tonnes CH4/compressor-day	87
Offshore Oil Production	Reciprocating Compressor Rod Packing (Average)	Adopted from API Compendium (2021) Table 6-37 (Assume 4 seals per compressor)	0.044657534	tonnes CH4/compressor-day	86.8
Offshore Oil Production	Centrifugal Compressor (Wet Seal)	Adopted from API Compendium (2021) Table 6-38 (Assume 2 seals per compressor)	0.236794521	tonnes CH4/compressor-day	86.8
Offshore Oil Production	Centrifugal Compressor (Dry Seal)	Adopted from API Compendium (2021) Table 6-38 (Assume 2 seals per compressor)	0.077232877	tonnes CH4/compressor-day	86.8
Offshore Gas Production	Reciprocating Compressor Rod Packing (Operating Mode)	Adopted from API Compendium (2021) Table 6-37 (Assume 4 seals per compressor)	0.0648	tonnes CH4/compressor-day	87
Offshore Gas Production	Reciprocating Compressor Rod	Adopted from API Compendium (2021) Table 6-	0.0648	tonnes CH4/compressor-day	87

	Packing (Standby Mode)	37 (Assume 4 seals per compressor)			
Offshore Gas Production	Reciprocating Compressor Rod Packing (Average)	Adopted from API Compendium (2021) Table 6-37 (Assume 4 seals per compressor)	0.044657534	tonnes CH4/compressor-day	86.8
Offshore Gas Production	Centrifugal Compressor (Wet Seal)	Adopted from API Compendium (2021) Table 6-38 (Assume 2 seals per compressor)	0.236794521	tonnes CH4/compressor-day	86.8
Offshore Gas Production	Centrifugal Compressor (Dry Seal)	Adopted from API Compendium (2021) Table 6-38 (Assume 2 seals per compressor)	0.077232877	tonnes CH4/compressor-day	86.8
Onshore Oil Production	Reciprocating Compressor Rod Packing (Operating Mode)	Adopted from API Compendium (2021) Table 6-37 (Assume 4 seals per compressor)	0.0648	tonnes CH4/compressor-day	87
Onshore Oil Production	Reciprocating Compressor Rod Packing (Standby Mode)	Adopted from API Compendium (2021) Table 6-37 (Assume 4 seals per compressor)	0.0648	tonnes CH4/compressor-day	87
Onshore Oil Production	Reciprocating Compressor Rod Packing (Average)	Adopted from API Compendium (2021) Table 6-37 (Assume 4 seals per compressor)	0.044657534	tonnes CH4/compressor-day	86.8
Onshore Oil Production	Centrifugal Compressor (Wet Seal)	Adopted from API Compendium (2021) Table 6-38 (Assume 2 seals per compressor)	0.236794521	tonnes CH4/compressor-day	86.8
Onshore Oil Production	Centrifugal Compressor (Dry Seal)	Adopted from API Compendium (2021) Table 6-	0.077232877	tonnes CH4/compressor-day	86.8

		38 (Assume 2 seals per compressor)			
Onshore Gas Production	Reciprocating Compressor Rod Packing (Operating Mode)	Adopted from API Compendium (2021) Table 6-37 (Assume 4 seals per compressor)	0.0648	tonnes CH4/compressor-day	87
Onshore Gas Production	Reciprocating Compressor Rod Packing (Standby Mode)	Adopted from API Compendium (2021) Table 6-37 (Assume 4 seals per compressor)	0.0648	tonnes CH4/compressor-day	87
Onshore Gas Production	Reciprocating Compressor Rod Packing (Average)	Adopted from API Compendium (2021) Table 6-37 (Assume 4 seals per compressor)	0.044657534	tonnes CH4/compressor-day	86.8
Onshore Gas Production	Centrifugal Compressor (Wet Seal)	Adopted from API Compendium (2021) Table 6-38 (Assume 2 seals per compressor)	0.236794521	tonnes CH4/compressor-day	86.8
Onshore Gas Production	Centrifugal Compressor (Dry Seal)	Adopted from API Compendium (2021) Table 6-38 (Assume 2 seals per compressor)	0.077232877	tonnes CH4/compressor-day	86.8
Gas Processing	Reciprocating Compressor Rod Packing (Operating Mode)	API Compendium (2021) Table 6-37 (Assume 4 seals per compressor)	0.0648	tonnes CH4/compressor-day	87
Gas Processing	Reciprocating Compressor Rod Packing (Standby Mode)	Adopted from API Compendium (2021) Table 6-37 (Assume 4 seals per compressor)	0.0648	tonnes CH4/compressor-day	87
Gas Processing	Reciprocating Compressor Rod Packing (Average)	API Compendium (2021) Table 6-37 (Assume 4 seals per compressor)	0.044657534	tonnes CH4/compressor-day	86.8

Gas Processing	Centrifugal Compressor (Wet Seal)	API Compendium (2021) Table 6-38 (Assume 2 seals per compressor)	0.236794521	tonnes CH4/compressor-day	86.8
Gas Processing	Centrifugal Compressor (Dry Seal)	API Compendium (2021) Table 6-38 (Assume 2 seals per compressor)	0.077232877	tonnes CH4/compressor-day	86.8
Gas Transmission	Reciprocating Compressor Rod Packing (Operating Mode)	API Compendium (2021) Table 6-40 (Assume 4 seals per compressor)	0.04704	tonnes CH4/compressor-day	93.4
Gas Transmission	Reciprocating Compressor Rod Packing (Standby Mode)	API Compendium (2021) Table 6-40 (Assume 4 seals per compressor)	0.02976	tonnes CH4/compressor-day	93.4
Gas Transmission	Reciprocating Compressor Rod Packing (Average)	API Compendium (2021) Table 6-40 (Assume 4 seals per compressor)	0.17808	tonnes CH4/compressor-day	93.4
Gas Transmission	Centrifugal Compressor (Wet Seal)	API Compendium (2021) Table 6-41 (Assume 2 seals per compressor)	0.4416	tonnes CH4/compressor-day	93.4
Gas Transmission	Centrifugal Compressor (Dry Seal)	API Compendium (2021) Table 6-41 (Assume 2 seals per compressor)	0.138	tonnes CH4/compressor-day	93.4
Gas Storage	Reciprocating Compressor Rod Packing (Operating Mode)	API Compendium (2021) Table 6-40 (Assume 4 seals per compressor)	0.05784	tonnes CH4/compressor-day	93.4
Gas Storage	Reciprocating Compressor Rod Packing (Standby Mode)	API Compendium (2021) Table 6-40 (Assume 4 seals per compressor)	0.05616	tonnes CH4/compressor-day	93.4

Gas Storage	Reciprocating Compressor Rod Packing (Average)	API Compendium (2021) Table 6-40 (Assume 4 seals per compressor)	0.19176	tonnes CH4/compressor-day	93.4
Gas Storage	Centrifugal Compressor (Wet Seal)	API Compendium (2021) Table 6-41 (Assume 2 seals per compressor)	0.4416	tonnes CH4/compressor-day	93.4
Gas Storage	Centrifugal Compressor (Dry Seal)	API Compendium (2021) Table 6-41 (Assume 2 seals per compressor)	0.138	tonnes CH4/compressor-day	93.4
Gas Distribution	Reciprocating Compressor Rod Packing (Operating Mode)	Adopted from API Compendium (2021) Table 6-40 (Assume 4 seals per compressor)	0.04704	tonnes CH4/compressor-day	93.4
Gas Distribution	Reciprocating Compressor Rod Packing (Standby Mode)	Adopted from API Compendium (2021) Table 6-40 (Assume 4 seals per compressor)	0.02976	tonnes CH4/compressor-day	93.4
Gas Distribution	Reciprocating Compressor Rod Packing (Average)	Adopted from API Compendium (2021) Table 6-40 (Assume 4 seals per compressor)	0.17808	tonnes CH4/compressor-day	93.4
Gas Distribution	Centrifugal Compressor (Wet Seal)	Adopted from API Compendium (2021) Table 6-41 (Assume 2 seals per compressor)	0.4416	tonnes CH4/compressor-day	93.4
Gas Distribution	Centrifugal Compressor (Dry Seal)	Adopted from API Compendium (2021) Table 6-41 (Assume 2 seals per compressor)	0.138	tonnes CH4/compressor-day	93.4
Petroleum Refining	Reciprocating Compressor Rod Packing (Operating Mode)	Adopted from API Compendium (2021) Table 6-40 (Assume 4 seals per compressor)	0.04704	tonnes CH4/compressor-day	93.4

Petroleum Refining	Reciprocating Compressor Rod Packing (Standby Mode)	Adopted from API Compendium (2021) Table 6-40 (Assume 4 seals per compressor)	0.02976	tonnes CH4/compressor-day	93.4
Petroleum Refining	Reciprocating Compressor Rod Packing (Average)	Adopted from API Compendium (2021) Table 6-40 (Assume 4 seals per compressor)	0.17808	tonnes CH4/compressor-day	93.4
Petroleum Refining	Centrifugal Compressor (Wet Seal)	Adopted from API Compendium (2021) Table 6-41 (Assume 2 seals per compressor)	0.4416	tonnes CH4/compressor-day	93.4
Petroleum Refining	Centrifugal Compressor (Dry Seal)	Adopted from API Compendium (2021) Table 6-41 (Assume 2 seals per compressor)	0.138	tonnes CH4/compressor-day	93.4

APPENDIX D: “EFs – Equipment Leaks” Worksheet Supplemental Tables

Table D-1: Available Selections for Process Units When Determining Equipment Leaks

Blowdown System: Generic (Pit or Vent)
Chemical Injection Pump: Pneumatic (Diaphragm Type)
Chemical Injection Pump: Pneumatic (Piston Type)
Chemical Injection Pump: Pneumatic (Unknown Type)
Chemicals (Fixed - Roof Tank with Natural Gas Blanketing)
Compressor: Centrifugal: (Stages: 1) (Seals: Wet) (Driver: Electric Motor)
Compressor: Centrifugal: (Stages: 1) (Seals: Wet) (Driver: Gas Turbine)
Compressor: Centrifugal: (Stages: 2) (Seals: Wet) (Driver: Electric Motor)
Compressor: Centrifugal: (Stages: 2) (Seals: Wet) (Driver: Gas Turbine)
Compressor: Centrifugal: (Stages: 1) (Seals: Dry) (Driver: Electric Motor)
Compressor: Centrifugal: (Stages: 1) (Seals: Dry) (Driver: Gas Turbine)
Compressor: Centrifugal: (Stages: 2) (Seals: Dry) (Driver: Electric Motor)
Compressor: Centrifugal: (Stages: 2) (Seals: Dry) (Driver: Gas Turbine)
Compressor: Reciprocating: (Stages: 1) (Driver: Electric Motor)
Compressor: Reciprocating: (Stages: 1) (Driver: Recip Engine)
Compressor: Reciprocating: (Stages: 2) (Driver: Electric Motor)
Compressor: Reciprocating: (Stages: 2) (Driver: Recip Engine)
Compressor: Reciprocating: (Stages: 3) (Driver: Electric Motor)
Compressor: Reciprocating: (Stages: 3) (Driver: Recip Engine)
Compressor: Screw (Driver: Electric Motor)
Compressor: Screw (Driver: Recip Engine)
Condensate (External Floating - Roof Tank)
Condensate (Fixed - Roof Tank with Vapor Control)

Condensate (Fixed - Roof Tank without Vapor Control)
Condensate (Internal Floating - Roof Tank))
Dehydration: Desiccant (Adsorber Columns: 2)
Dehydration: Desiccant (Adsorber Columns: 3)
Dehydration: Glycol (with Gas-assisted Pump)
Dehydration: Glycol (without Gas-assisted Pump)
District Regulating Station
Drain Tank
Flare System: Generic (Including Knock-out Drum)
Gate Station
Heat Exchanger: Gas/Gas
Heat Exchanger: Gas/Liquid
Heater/Boiler/Reboiler: Generic (Burner Assemblies: 1)
Heater/Boiler/Reboiler: Generic (Burner Assemblies: 2)
Heater/Boiler/Reboiler: Generic (Burner Assemblies: 3)
Heater/Boiler/Reboiler: Line (Burner Assemblies: 1)
Heater/Boiler/Reboiler: Line (Burner Assemblies: 2)
Heater/Boiler/Reboiler: Line (Burner Assemblies: 3)
Heater/Boiler/Reboiler: Treater (Burner Assemblies: 1)
Heater/Boiler/Reboiler: Treater (Burner Assemblies: 2)
Heater/Boiler/Reboiler: Treater (Burner Assemblies: 3)
Hydrocarbon Dewpoint Control: Joule-Thomson Unit (Excluding Compressor)
Hydrocarbon Dewpoint Control: Propane Refrigeration
Inlet Header : Heavy Oil Battery
Inlet Header: Conventional Oil Battery
Inlet/Outlet Header: Gas Facilities (Fittings Per Pipeline)
Inlet/Outlet Header: Oil Facilities (Fittings Per Pipeline)
Isolation Block Valve
LPG Extraction: Deepcut (C2 to C4)
LPG Extraction: Shallow Cut (C3 to C4)

Mainline Block Valve
Meter Run: Generic
Meter Set: Commercial
Meter Set: Farm Tap
Meter Set: Industrial
Meter Station: Border
Meter Station: Receipt/Sales
Meter Set: Residential
NGL – Natural Gas Liquefaction
PIG Receiver or Sender
Power Generator: Natural Gas Fuelled (Driver: Gas Turbine)
Power Generator: Natural Gas Fuelled (Driver: Recip. Engine)
Produced Water (External Floating - Roof Tank)
Produced Water (Fixed - Roof Tank with Vapor Control)
Produced Water (Fixed - Roof Tank without Vapor Control)
Produced Water (Internal Floating - Roof Tank)
Pump: Natural Gas Fuelled (Driver: Recip. Engine)
Refrigeration (Propane)
Separator: Filter Separator
Separator: Horizontal (Phases: 2)
Separator: Horizontal (Phases: 3)
Separator: Vertical (Phases: 2)
Separator: Vertical (Phases: 3)
Stabilizer: with Reflux Loop
Stabilizer: without Reflux Loop
Storage Tank (Produced Oil, with Vapor Control)
Storage Tank (Produced Oil, without Vapor Control)
Storage Tank (Produced Water, with Vapor Control)
Storage Tank (Produced Water, without Vapor Control)
Sulphur Recovery: Claus
Sulphur Recovery: MCRC (Sub-dewpoint)

Sweetening: (Physical Solvent)
Sweetening: Chemsweet
Sweetening: DEA (Diethanolamine)
Sweetening: DGA (Diglycolamine)
Sweetening: Generic
Sweetening: Iron Sponge
Sweetening: LoCat
Sweetening: MDEA (Monodiethanolamine)
Sweetening: MEA (Monoethanolamine)
Sweetening: Selexol
Sweetening: Sulfacheck
Sweetening: Sulfinol
Vapor Recovery Unit: Offshore
Vapor Recovery Unit: Onshore
Well: Conventional Oil
Well: Gas
Well: Heavy Oil
Well: Offshore

APPENDIX E: "Constants" Worksheet Supplemental Tables

Table E-1: Chemical Library

Substance		Molecular Weight	Gas Density at STP		Liquid Density		Specific Heat Capacity (Cp)		
Name	Formula	(kg/kmol)	At 15°C	At Standard T	At 15°C		Ideal Gas		Liquid
			(kg/m3)	(kg/m3)	(kg/m3)	(Nm3/kmol)	(kJ/(kg·°C)	(kJ/kmol·°C)	(kJ/(kg·°C)
Methane	CH_4	16.043	0.678	0.678	300.000	0.050	2.204	35.359	0.000
Ethane	C_2H_6	30.070	1.272	1.272	357.800	0.084	1.706	51.299	3.807
Propane	C_3H_8	44.097	1.865	1.865	507.800	0.087	1.625	71.658	2.476
iso-Butane	C_4H_{10}	58.124	2.458	2.458	563.200	0.103	1.616	93.928	2.366
n-Butane	C_4H_{10}	58.124	2.458	2.458	584.200	0.099	1.652	96.021	2.366
iso-Pentane	C_5H_{12}	72.151	3.051	3.051	624.400	0.116	1.600	115.442	2.239
n-Pentane	C_5H_{12}	72.151	3.051	3.051	631.000	0.114	1.622	117.029	2.292
Hexane	C_6H_{14}	86.178	3.645	3.645	663.800	0.130	1.613	139.005	2.231
Heptane	C_7H_{16}	100.205	4.238	4.238	688.000	0.146	1.606	160.929	2.209
Octane	C_8H_{18}	114.229	4.831	4.831	706.700	0.162	1.601	182.881	2.191
Nonane	C_9H_{20}	128.255	5.424	5.424	721.700	0.178	1.598	204.951	2.184
Decane	$C_{10}H_{22}$	142.282	6.017	6.017	733.900	0.194	1.595	226.940	2.179
Hydrogen Sulphide	H_2S	34.076	1.441	1.441	789.000	0.043	0.996	33.940	0.996
Carbon Dioxide	CO_2	44.010	1.861	1.861	821.900	0.054	0.833	36.660	0.000
Nitrogen	N_2	28.013	1.185	1.185	808.600	0.035	1.040	29.134	0.000
Water	H_2O	18.015	0.762	0.762	999.100	0.018	1.862	33.544	4.191

Sulphur Dioxide	SO_2	64.059	2.709	2.709	1,396.00	0.046	0.606	38.833	1.359
Oxygen	O_2	31.999	1.353	1.353	1,141.00	0.028	0.917	29.330	0.000

Table E-2: Chemical Library Continued

Substance	**Lower Heating Value**				**Higher Heating Value**			
Name	**At 15°C**		**At Standard T**		**At 15°C**		**At Standard T**	
	(MJ/m3)	**(MJ/kmol)**	**(MJ/kmol)**	**(GJ/10^3 Nm3)**	**(MJ/m3)**	**(MJ/kmol)**	**(MJ/kmol)**	**(GJ/10^3 m3)**
Methane	33.936	802.411	802.411	33.936	37.694	891.268	891.3	37.694
Ethane	60.395	1,428.029	1,428.029	60.395	66.032	1,561.315	1,561.3	66.032
Propane	86.456	2,044.237	2,044.237	86.456	93.972	2,221.951	2,222.0	93.972
iso-Butane	112.031	2,648.953	2,648.953	112.031	121.426	2,871.096	2,871.1	121.426
n-Butane	112.384	2,657.300	2,657.300	112.384	121.779	2,879.443	2,879.4	121.779
iso-Pentane	138.044	3,264.026	3,264.026	138.044	149.319	3,530.621	3,530.6	149.319
n-Pentane	138.380	3,271.970	3,271.970	138.380	149.654	3,538.542	3,538.5	149.654
Hexane	164.402	3,887.256	3,887.256	164.402	177.556	4,198.280	4,198.3	177.556
Heptane	190.398	4,501.927	4,501.927	190.398	205.431	4,857.379	4,857.4	205.431
Octane	216.372	5,116.077	5,116.077	216.372	233.285	5,515.982	5,516.0	233.285
Nonane	242.398	5,731.458	5,731.458	242.398	261.19	6,175.791	6,175.8	261.190
Decane	268.393	6,346.105	6,346.105	268.393	289.064	6,834.867	6,834.9	289.064
Hydrogen Sulphide	21.912	518.105	518.105	21.912	23.791	562.534	562.5	23.791
Carbon Dioxide	0	0	0.000	0.000	0	0	0.0	0.000
Nitrogen	0.000	0.000	0.000	0.000	0	0.000	0.0	0.000
Water	0	0	0.000	0.000	0	0	0.0	0.000
Sulphur Dioxide	0.000	0.000	0.000	0.000	0	0.000	0.0	0.000
Oxygen	0	0	0.000	0.000	0	0	0.0	0.000

Table E-3: Chemical Library Continued

Substance	**Composition (Atoms/Molecule)**					**Carbon Content**	
Name	**C**	**H**	**S**	**N**	**O**	**(tonnes/10^3 Nm3)**	**kg/kg**
Methane	1	4	0	0	0	0.508	0.749
Ethane	2	6	0	0	0	1.016	0.799
Propane	3	8	0	0	0	1.524	0.817
iso-Butane	4	10	0	0	0	2.032	0.827
n-Butane	4	10	0	0	0	2.032	0.827
iso-Pentane	5	12	0	0	0	2.540	0.832
n-Pentane	5	12	0	0	0	2.540	0.832
Hexane	6	14	0	0	0	3.048	0.836
Heptane	7	16	0	0	0	3.556	0.839
Octane	8	18	0	0	0	4.064	0.841
Nonane	9	20	0	0	0	4.572	0.843
Decane	10	22	0	0	0	5.080	0.844
Hydrogen Sulphide	0	2	1	0	0	0.000	0.000
Carbon Dioxide	0	0	0	0	0	0.000	0.000
Nitrogen	0	0	0	2	0	0.000	0.000
Water	0	2	0	0	1	0.000	0.000
Sulphur Dioxide	0	0	1	2	0	0.000	0.000
Oxygen	0	0	0	0	2	0.000	0.000

Table E-4: Molecular Weight of Various Substances

Substance	**Symbol**	**Molecular Weight**
Carbon Monoxide	CO	28.010
Nitrous Oxide	N2O	44.013
Oxides of Nitrogen	NOx	46.006
Non-Methane VOC	NMVOC	35.08

Table E-5: Atomic Data

Name	Formula	Atomic Mass
Carbon	C	12.011
Hydrogen	H	1.00784
Oxygen	O	15.999
Nitrogen	N	140067
Sulphur	S	32.065

Table E-6: Miscellaneous Constants

Constant	Value	Unit
Standard Temperature	15	°C
Standard Pressure	101.325	kPa
Standard Volume	23.64	m3/kmol
Ambient Pressure	100.00	kPa
Gas Constant	8.3144598	m3·kPa·kmol-1·°K-1
NG Specific Heat Ratio	1.32	Dimensionless
NG Molecualr Weight	18.625504	kg/kmol
NG Density	0.7877202	kg/m3
Air Specific Heat Ratio	1.4	Dimensionless
Air Molecular Weight	28.9647	kg/kmol
Air Cv Specific Heat	717.5	J/kg
Air Cp Specific Heat	1005	J/kg
Air Density	1.2249912	kg/m3
Fuel Gas HHV	42.295567	MJ/m3
Fuel Gas LHV	38.250156	MJ/m3
Fuel Gas Molecular Weight	18.872111	kg/kmol
Fuel Gas Density	0.7981498	kg/kmol
Flare Gas HHV	40.255408	MJ/m3
Acid Gas HHV	68.424444	MJ/m3
NMVOC HHV	76.00658	MJ/m3
NMVOC LHV	69.698777	MJ/m3

APPENDIX F: Lookup Tables and Lookup Lists Worksheets Supplemental Tables

Table F-1: Unit Conversion Values

From	To	Conversion Factor	
		Value	Descriptor
g/gal	tonne/m3	0.000264172	"g/gal" to "tonne/m3"
g/ton	tonne/tonne	1.10231E-06	"g/ton" to "tonne/tonne"
g/scf	kg/Nm3	0.035314662	"g/scf" to "kg/Nm3"
kg CH4/activity	m3 CH4/activity	1.47384043	"kg CH4/activity" to "m3 CH4/activity"
lb CH4	m3 CH4	0.668522	"lb CH4" to "m3 CH4"
lb/10^3 gal	tonne/m3	0.119826428	"lb/10^3 gal" to "tonne/m3"
lb/mmBTU	tonnes/GJ	0.000430	"lb/mmBTU" to "tonnes/GJ"
lb/mmscf	tonne/10^3 m3	1.60185E-05	"lb/mmscf" to "tonne/10^3 m3"
lb/ton	tonne/tonne	0.0005	"lb/ton" to"tonne/tonne"
mile	km	1.609344	"mile" to "km"
scf/106 scf gas processed	m3/106 m3 gas processed	1	"scf/106 scf gas processed" to "m3/106 m3 gas processed"
scf/activity	m3/activity	0.028317	"scf/activity" to "m3/activity"
scf/h/device	m3/d/device	0.6796044	"scf/h/devioce" to "m3/d/device"
scf/d/device	m3/d/device	0.028317	"scf/d/device" to "m3/d/device"
scf/y/pipeline-mile	m3/y/pipeline-km	0.017595275	"scf/y/pipeline-mile" to "m3/y/pipeline-km"
scf/y/source	m3/y/source	0.028317	"scf/y/source" to "m3/y/source"
tonnes CH4	m3 CH4	1473.84043	"tonnes CH4" to "m3 CH4"
tonnes CH4/pipeline-mile	m3 CH4/pipeline-km	915.8019853	"tonnes CH4/pipeline-mile" to "m3 CH4/pipeline-km"
tonnes CH4/1000 bbl of Liquid	m3 CH4/m3 of Liquid	9.3	"tonnes CH4/1000 bbl of Liquid" to "m3 CH4/m3 of Liquid"
tonnes CH4/d/source	m3 CH4/d/source	1,473.8	"tonnes CH4/d/source" to "m3 CH4/d/source"
tonnes CH4/m3 of Liquid	m3 CH4/m3 of Liquid	1473.84043	"tonnes CH4/m3 of Liquid" to "m3 CH4/m3 of Liquid"
m^3/h	m3/h	1.000000	"m^3/h" to "m3/h"
m^3/d	m3/h	0.041666667	"m^3/d" to "m3/h"

kPa	psi	0.1450377	"kPa" to "psi"
m3/d	E3 m3/d	0.001	"m3/d" to "E3 m3/d"
m3/d	scf/h	1.471444447	"m3/d" to "scf/h"
m3/d	mmscf/d	3.53147E-05	"m3/d" to "mmscf/d"
kg/m3	lb/ft3	0.062427881	"kg/m3" to "lb/ft3l"
m3/d	m3/mo	30.41666667	"m3/d" to "m3/h"
m3/d	m3/y	365	"m3/d" to "m3/h"
m3/d	gal/h	11.00717083	"m3/d" to "gal/h"
m3/d	bbl/d	6.28981057	"m3/d" to "bbll/d"
m3/d	bbl/mo	191.3150715	"m3/d" to "bbl/mo"
m3/d	bbl/y	2295.780858	"m3/d" to "bbl/y"
m3/d	E3 m3/y	0.365	"m3/d" to "E3 m3/y"
kW	HP	1.341022	"kW" to "HP"
HP	kW	0.7456999	"HP" to "kW"
kW	GJ/h	0.0036	"kW" to "GJ/h"
mmBTU/h	kW	292.8104	"mmBTU/h" to "kW"
GJ/H	kW	277.7777778	"GJ/h" to "kW"
tonne	kg	1000	"tonne" to "kg"
y	h	8760	"y" to "h"
kg/h	lb/h	2.20462	"kg/h" to "lb/h"
kg/h	ton/d	0.0264552	"kg/h" to "ton/d"
kg/h	tonne/d	0.024	"kg/h" to "tonne/d"
kg/h	ton/mo	0.804679	"kg/h" to "ton/mo"
kg/h	tonne/mo	0.73	"kg/h" to "tonne/mo"
kg/h	ton/y	9.656148	"kg/h" to "ton/y"
kg/h	tonne/y	8.76	"kg/h" to "tonne/y"
m3/h	gal/h	264.1721	"m3/h" to "gal/h"
m3/h	L/h	1000	"m3/h" to "L/h"
m3/h	gal/d	6340.1304	"m3/h" to "gal/d"
m3/h	m3/d	24	"m3/h" to "m3/d"
m3/h	gal/mo	192845.633	"m3/h" to "gal/mo"
m3/h	m3/mo	730	"m3/h" to "m3/mo"
m3/h	gal/y	2314147.596	"m3/h" to "gal/y"

m3/h	m3/y	8760	"m3/h" to "m3/y"
m3/h	scf/h	35.31466672	"m3/h" to "scf/h"
m3/h	mscf/d	0.847552001	"m3/h" to "mscf/d"
m3/h	E3 m3/d	0.024	"m3/h" to "E3 m3/d"
m3/h	mscf/mo	25.77970671	"m3/h" to "mscf/mo"
m3/h	E3 m3/mo	0.73	"m3/h" to "E3 m3/mo"
m3/h	mscf/y	309.3564805	"m3/h" to "mscf/y"
m3/h	E3 m3/y	8.76	"m3/h" to "E3 m3/y"
m3/d	m3/d	1	"m3/d" to "m3/d"
E3 m3/d	scf/h	1471.444447	"E3 m3/d" to "scf/h"
E3 m3/d	m3/h	41.66666667	"E3 m3/d" to "m3/h"
E3 m3/d	mscf/d	35.31466672	"E3 m3/d" to "mscf/d"
E3 m3/d	mmscf/d	0.035314667	"E3 m3/d" to "mmscf/d"
E3 m3/d	E3 m3/d	1	"E3 m3/d" to "E3 m3/d"
E3 m3/d	E6 m3/d	0.001	"E3 m3/d" to "E6 m3/d"
E3 m3/d	mscf/mo	1074.154446	"E3 m3/d" to "mscf/mo"
E3 m3/d	mmscf/mo	1.074154446	"E3 m3/d" to "mmscf/mo"
E3 m3/d	E6 m3/mo	0.030416667	"E3 m3/d" to "E6 m3/mo"
E3 m3/d	mmscf/y	12.88985335	"E3 m3/d" to "mmscf/y"
E3 m3/d	bscf/y	0.012889853	"E3 m3/d" to "bscf/y"
E3 m3/d	E6 m3/y	0.365	"E3 m3/d" to "E6 m3/y"
E3 m3/d	E3m3/y	365	"E3 m3/d" to "E6 m3/y"
E3 m3/d	m3/d	1000	"E3 m3/d" to "m3/d"
E3 m3/d	E3 m3/mo	30.41666667	"E3 m3/d" to "E3 m3/mo"
kPa (g)	psi(g)	0.1450377	"kPa(g)" to "psi(g)"
kPa (g)	kPa(g)	1	"kPa(g)" to "kPa(g)"
kPa (g)	kg/cm2(g)	0.01019716	"kPa(g)" to "kg/cm2(g)"
kPa (g)	bar(g)	0.01	"kPa(g)" to "bar(g)"
kPa	oz/in2	0.009064856	"kPa" to "oz/in2"
kPa	Pa	0.001	"kPa" to "Pa"
kPa	kPa	1	"kPa" to "kPa"
kPa	bar	0.01	"kPa" to "bar"
kPa	kg/cm2	0.010197162	"kPa" to "kg/cm2"

kW	kW	1	"kW" to "kW"
kW	kWh/d	24	"kW" to "kWh/d"
kW	kWh/mo	730	"kW" to "kWh/mo"
kW	MWh/y	8.76	"kW" to "MWh/y"
kW	mBTU/h	3.415179	"kW" to "mBTU/h"
kW	mmBTU/h	0.003415179	"kW" to "mmBTU/h"
kW	MW	0.001	"kW" to "MW"
kg/m3	lb/gal	0.008345393	"kg/m3" to "lb/gal"
m3/m3 Oil	scf/bbl Oil	5.614584034	"m3/m3 Oil" to "scf/bbl Oil"
m3/m3 Water	scf/bbl Water	5.614584034	"m3/m3 Water" to "scf/bbl Water"
GJ/y	mBTU/h	0.108198299	"GJ/y" to "mBTU/h"
GJ/y	mmBTU/d	0.002596759	"GJ/y" to "mmBTU/d"
GJ/y	mmBTU/mo	0.078984758	"GJ/y" to "mmBTU/mo"
GJ/y	mmBTU/y	0.9478171	"GJ/y" to "mmBTU/y"
GJ/y	MJ/h	0.114155251	"GJ/y" to "MJ/h"
GJ/y	GJ/d	0.002739726	"GJ/y" to "GJ/d"
GJ/y	GJ/mo	0.083333333	"GJ/y" to "GJ/mo"
E3 m3/d	E6 m3/d	0.001	"E3 m3/d" to "E6 m3/d"

Table F-2: Leak Control Factors

Equipment Type	**Modification**	**Control Efficiency (%)**
Compressor Crankcase Vent	Closed-vent System	90
Compressor Crankcase Vent	None	0
Compressor Seals	Closed-vent System	90
Compressor Seals	Dual Mechanical Seals With Barrier Fluid System	100
Compressor Seals	None	0
Connectors	None	0
Connectors	Welded Together	100
Drains	Closed-vent System	90
Drains	None	0
Open-Ended Lines	Blind, Cap, Plug or Second Valve	100

Open-Ended Lines	None	0
Others	None	0
Pressure Relief Devices	Closed-Vent System	90
Pressure Relief Devices	None	0
Pressure Relief Devices	Rupture Disk Assembly	100
Pumps	Closed-Vent System	90
Pumps	Dual Mechanical Seals With Barrier Fluid System	100
Pumps	None	0
Pumps	Sealless Design	100
Regulators	None	0
Sampling Connections	Blind, Cap, Plug or Second Valve	100
Sampling Connections	None	0
Valves	None	0
Valves	Sealless Design	100

Table F-3: Available User-Defined Facility Types

Offshore Oil Production	**Offshore Gas Production**	**Onshore Oil Production**	**Onshore Gas Production**	**Gas Processing**	**Gas Transmission**	**Gas Storage**	**Gas Distribution**	**Petroleum Refining**
Processing Platform	Processing Platform	Abandoned wells	Abandoned wells	LNG Plant (Liquefaction)	Compressor Station	Storage Facility	Compressor Station	Conventional and Synthetic Crude Oil
Production Platform (c/w Compression)	Production Platform (c/w Compression)	Group Battery - Extra Heavy Oil	Compressor Station - Gas Gathering	Sour Gas Plant	LNG Peak Shaving	Storage Well	Distribution LNG Satellite	Heavy Oil
Production Platform (wells only)	Production Platform (wells only)	Group Battery - Heavy Oil	Field Dehydrator	Sweet Gas Plant	LNG Regasification		Main Lines	
		Group Battery - Oil	Gas Exploration		LNG Shipping		Post-Meter	
		Oil Exploration	Group Battery - Gas		LNG Transport (Truck or Rail)		Pressure Regulator Station	
		Oil Sands Mine and Ore Processing	Other (Conventional)		Pipeline		Receipt Meter Station	
		Oil Sands Upgrading	Other (Unconventional)		Receipt Meter Station		Sales Meter Station - Commercial	
		Oil Terminal (Marine)	Single-Well Battery - Gas		Sales Meter Station		Sales Meter Station - Industrial	
		Oil Terminal (Pipeline)					Sales Meter Station - Residential	
		Oil Terminal (Truck & Rail)					Service Lines	
		Other (Conventional)						
		Other (Unconventional)						
		Single-Well Battery - Extra Heavy Oil						

		Single-Well Battery - Heavy Oil						
		Single-Well Battery - Oil						

Table F-4: Available Units of Measure for Combusted Fuels

Solid (Input Unit of Measure)	**Liquid (Input Unit of Measure)**	**Gaseous (Input Unit of Measure)**
lb/h	gal/h	scf/h
kg/h	L/h	m3/h
ton/d	gal/d	mscf/d
tonne/d	m3/d	E3 m3/d
ton/mo	gal/mo	mscf/mo
tonne/mo	m3/mo	E3 m3/mo
ton/y	gal/y	mscf/y
tonne/y	m3/y	E3 m3/y

Table F-5: Available Units of Measure for Oil and Produced Water Receipts

Oil (Input Unit of Measure)	**Water (Input Unit of Measure)**
gal/h	gal/h
m3/h	m3/h
bbl/d	bbl/d
m3/d	m3/d
bbl/mo	bbl/mo
m3/mo	m3/mo
bbl/y	bbl/y
E3m3/y	E3m3/y

Table F-6: Available Units of Measure for Natural Gas Receipts

Natural Gas Receipts (input Units of Measure)
scf/h
m3/h
mscf/d
mmscf/d
E3 m3/d
E6 m3/d

mscf/mo
mmscf/mo
E6 m3/mo
mmscf/y
bscf/y
E6 m3/y

Table F-7: Available Units of Measure for Vented and Flared Volumes

Vented Natural Gas (Input Unit of Measure)	**Flared (Input Unit of Measure)**
scf/h	scf/h
m3/h	m3/h
mscf/d	mscf/d
m3/d	m3/d
E3 m3/d	E3 m3/d
E3 m3/mo	E3 m3/mo
mscf/mo	mscf/mo
mmscf/y	mmscf/y
E6 m3/y	E6 m3/y

Table F-8: Available Units of Measure for Heat Purchases

Heat Purchased (Input Unit of Measure)
mBTU/h
mmBTU/d
mmBTU/mo
mmBTU/y
MJ/h
GJ/d
GJ/mo
GJ/y

Table F-9: Available Units of Measure for Gauge Pressure and Absolute Pressure

Gauge Pressure (Input Unit of Measure)	**Absolute Pressure (Input Unit of Measure)**
psi(g)	oz/in2
kPa(g)	Pa
kg/cm2(g)	psi
bar(g)	kPa
	kg/cm2
	bar

Table F-10: Available Units of Measure for Oil Density

Oil Density (Input Unit of Measure)
kg/m3
lb/gal
lb/ft3
API

Table F-11: Available Units of Measure for Flash Gas Factors

Flash Gas Factor for Oil (Input Unit of Measure)	**Flash Gas Factor for Produced Water (Input Unit of Measure)**
scf/bbl of Oil	scf/bbl of Water
m3/m3 of Oil	m3/m3 of Water

Table F-12: Available Units of Measure for Electricity Consumption or Generation

Electricity Consumption or Generation (Input Unit of Measure)
kW
kWh/d
kWh/mo
MWh/y

Table F-13: Available Units of Measure for Heater and Boiler Output Power Rating

Heater & Boiler Output Power Rating (Input Unit of Measure)
mBTU/h
mmBTU/h
GJ/h
kW
MW

Table F-14: Available Units of Measure for Engine Output Power Rating

Engine Output Power Rating (Input Unit of Measure)
HP
kW
MW

Table F-15: Available Options for "Emitted Substance Type"

Emitted Substance
Natural Gas
Methane

Table F-16: Available Options within Various Lists

List	**Valid Options**
Industry Segment	
	Offshore Oil Production
	Offshore Gas Production
	Onshore Oil Production
	Onshore Gas Production
	Gas Processing
	Gas Transmission
	Gas Storage
	Gas Distribution
	Petroleum Refining
Dehydrator Types	
	Without Gas-Assisted Pump Emissions
	With Gas-Assisted Pump Emissions

Pneumatic Supply Gas	
	Compressed Air
	Natural Gas
Hydrocarbon Liquids	
	Light
	Medium
	Heavy
	Very Heavy
Type of Controllers	
	Not Applicable
	Low-Bleed
	High-Bleed
	Intermittent Bleed
	No-Bleed
Source of Quantity	
	Calculated
	Engineering Judgement
	Measured
	Reported by Facility
Source of Property	
	Default
	Measured
	Calculated
Fuel Category	
	Solid
	Liquid
	Gaseous
Fuel Category	
	Liquid
	Gaseous
Solid Fuels	
	Anthracite
	Bituminous
	Lignite
	Cleaned Coal
	Other Washed Coal
	Briquette Coal
	Coke
	Petroleum Coke
Liquid Fuels	
	Crude Oil
	Fuel Oil
	Gasoline

	Diesel
	Aviation Kerosene
	Common Kerosene
	Naphtha
	Liquefied Petroleum Gas
	Liquefied Natural Gas
	Propane (liquid)
Gaseous Fuels	
	Natural Gas
Application Type	
	Turbine
	Gas Engine (2-Stroke Lean-Burn)
	Gas Engine (4-Stroke Lean-Burn)
	Gas Engine (4-Stroke Rich-Burn)
	Heaters & Boilers
	Heaters & Boilers (Low-NOx)
Heater/Boiler Type	
	Heaters & Boilers
	Heaters & Boilers (Low-NOx)
Engine Type	
	Turbine
	Engine (Liquid Fuel)
	Gas Engine (2-Stroke Lean-Burn)
	Gas Engine (4-Stroke Lean-Burn)
	Gas Engine (4-Stroke Rich-Burn)
Basis	
	Manufacturer
	Engineering Judgement
Oil Storage System Type	
	Separator
	Treater
	Vapor Recovery Tower
Produced Water Storage System Type	
	Inlet Separator
	Free-Water Knock-Out
Vent Control Device	
	None
	Flare
	Vapor Recovery Compressor

APPENDIX G: Utilities and Compressibility Factors Worksheets Supplemental Information

There are a variety of different estimation and measurement techniques that may be used to assess the amount of methane emissions due to fugitive equipment leaks. These techniques may be divided into the following four categories, presented in the general order of increasing rigor and accuracy:

- Average emission factors.
- Screening-based approaches.
- Screening coupled with direct measurement of significant leakers.
- Whole-facility quantification approaches.

G.1 AVERAGE EMISSION FACTORS

The "average emission factor" method is the simplest, most cost-effective, but least reliable, approach for estimating emissions due to fugitive equipment leaks. It offers a reasonable first-order means of estimating total fugitive emissions from a large number of facilities or for an overall company. However, it assumes that the target facility or facilities are well represented by the industry average leak statistics. Often, this may be a poor assumption due to differences in environmental conditions, maintenance practices, age of equipment, equipment specifications, and design standards. The results are especially susceptible to errors when the method is applied to only a few facilities. For a single facility, the results may easily be in error by several orders of magnitude.

To apply the method, an inventory of equipment components must first be developed for each target facility or installation. Ideally, this should be done based on actual site surveys or counts taken from process flow diagrams and bills of materials. Using drawings and bills of materials is quite adequate for small, relatively simple, installations (e.g., receipt meter stations and farm taps). However, for larger facilities (e.g., compressor stations and gas processing plants), actual field counts are preferable since the drawings and bills of materials become tedious to use and may not provide complete details (especially on threaded piping and pre-packaged process units such as compressor units).

Special care must be taken when counting components to ensure that all potential leakage points are properly tallied and classified. For example, a threaded union is equivalent to three connectors, a flanged or threaded valve is counted as a valve, two connectors, and possibly an open-ended valve or line (i.e., if it is open to the atmosphere on one side). Appendix 3 describes specific procedures for counting equipment components.

In the absence of actual information, the default equipment schedules provided in the *SMART Plus* Facility template on the "Equipment Schedules" worksheet may be used.

The amount of compressor station yard piping, excluding suction and discharge headers and valving for each unit, was determined to be essentially independent of the number of compressor units. Accordingly, the total number of equipment components at a compressor station is calculated by adding the components from yard piping plus the components from each of the compressor units. The components from discharge coolers used on site must also be added.

Once the equipment component inventory has been compiled, the emissions are estimated using the equation:

$$\boldsymbol{ER_k = \sum_i \sum_j EF_{i,j} \cdot N_{i,j} \cdot OH_j \cdot X_{j,k}}$$

Equation G-1

Where

ER_k = Total leak rate (kg/h) of substance k for the target source population (i.e., a specific facility),
$EF_{i,j}$ = Applicable average emission factor (kg/h/source) for equipment components of type i in service j,
$N_{i,j}$ = Total number of potential components of type i in service j,
X_j = Mass fraction of substance k in the process fluid for service j,
OH_j = Annual operating hours the components in service j are in pressurized service (hours/year).

The potential fluid service categories are gas/vapor, light liquid, and heavy liquid.

The average emission factors are normally expressed as total hydrocarbon emissions. To calculate fugitive methane emissions for a facility, the gas composition must be known.

G.2 SCREENING-BASED APPROACHES

Screening-based approaches require that each target facility conduct a full leak detection program. This would normally be done using a portable intrinsically safe optical gas imaging (OGI) infrared (IR) camera in accordance U.S. EPA *Alternative Work Practice to Detect Leaks from Equipment* (https://www.federalregister.gov/documents/2008/12/22/E8-30196/alternative-work-practice-to-detect-leaks-from-equipment) or an organic vapor analyzer (OVA) in accordance with U.S. EPA Method 21 (https://www.epa.gov/emc/method-21-volatile-organic-compound-leaks). With the first approach, leakers are components that have visible emissions. With the latter approach, the OVA is used to measure the maximum concentration of organic vapors above background at each potential leakage point, and those that have a screening value equal to or greater than the regulatory leak definition are deemed to be leaking. The leaker results are recorded along with the corresponding type of component and service.

To achieve realistic results, the screening should be done towards the middle of a maintenance period (e.g., midway between scheduled facility turn-a-rounds). Most screening instruments will not function properly in cold weather, which makes screening difficult to do during the winter. Also, not all components are accessible for screening (e.g., due to high temperatures, heights, or being covered by insulation). Useful data to record during a leak survey includes the following (the critical items are presented in italicized text):

- Monitoring instrument type, model and last calibration date.
- Operator's name.
- Date.
- Facility name.
- Component identification number (if permanent IDs are not in place, assign IDs as each source is screened).
- Component type (e.g., valve, connector, open-ended line), style, and nominal size.
- Process unit/stream where the screened component is located.
- Process fluid type and composition.
- Process conditions (i.e., temperature and pressure).
- Ambient conditions (e.g., mean temperature, pressure, and wind speed).
- Service (i.e., gas, light liquid, or heavy liquid).
- Number of hours per year the component is in service.
- Screening value (ppm).
- Background concentration (ppm).
- Comments.

Facilities may apply response factors to raw OVA screening values to correct for the analyzer's sensitivity to the actual chemical composition of the sampled vapors. However, provided the instrument has been calibrated to methane, there will be little benefit in doing this (e.g., less than a 10 percent change in the estimated emissions). Some OVA manufacturers provide response factors in their user documentation. Also, some published values for selected OVAs are presented U.S. EPA (1995).

Facilities may use the data compiled from a leak survey to estimate leak rates by applying leak/no-leak emission factors.

To apply this approach, the screening values must be classified as either leaking (i.e., has a maximum screening value of 10,000 ppm or more) or non-leaking (i.e., has a maximum screening value of less than 10,000 ppm), and categorized by type of component and type of service. The amount of emissions is then estimated for each source category using the equation:

$$\boldsymbol{ER = \sum_{i} \sum_{j} N_{i,j} \cdot \left[\frac{EF_L \cdot n_L + EF_N \cdot n_N}{n_L + n_N}\right]_{i,j} \cdot X_j}$$

Equation G-69

Where

ER	=	Total methane leak rate (kg/h) of pollutant k for the target source population,
EF_L	=	Appropriate 'leaker' emission factor for the source/service category of interest,

EF_N = Appropriate non-leaking emission factor for the components of type i in service j,

n_L = Number of components screened and determined to be leaking (i.e., give a screening value of 10,000 ppm or more) for the source category of interest,

n_N = Number of components screened and determined not to be leaking (i.e., give a screening value of less than 10,000 ppm, including those sources with a screening value of zero) for the source category of interest,

$N_{i,j}$ = Total number of components of type i in service j (i.e., all components screened plus those not screened),

X_j = Mass fraction of methane in the process stream.