Methane Emissions Estimation Protocol

Prepared for:

ONE
OUR NATION'S ENERGY
FUTURE

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DOCUMENT VERSION CONTROL PAGE

Version	Date	Explanation
Original	August 3, 2016	Original Version of Protocol, approved by ONE Future members, posted to website
Version 2	August 27, 2018	Revised by ONE Future to reflect minor changes
Version 3	August 3, 2020	Updated to show T&S mileage surrogate for throughput, corrected Appendix C Equations, added Appendix D to clarify annual ONE Future segment methane intensity calculations, updated some “examples”, corrected format errors, and made other minor clarifications
Version 4	December 1, 2021	Updated to include LNG Storage with T&S calculations, company-specific way of calculating T&S methane intensity using PHMSA throughput (a method described here but not used in the official report), additional distribution emission sources from other material mains and services, and made other minor clarifications
Version 5	January 10, 2023	Revised to include updated combustion exhaust methane emissions calculation methodology update for the production, G&B, processing, and T&S segments. Also revised to include emissions from tanks at underground natural gas storage sites and emissions from odorizers at distribution facilities.
Version 6	December 15, 2023	Updated to include more detailed information about the combustion exhaust methane emissions calculation methodology in Appendix B. Also revised to include updated underground storage and LNG storage allocation to both the T&S and Distribution segments in Appendices B and D.

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Acknowledgements:

ONE Future gratefully acknowledges the contribution of the following participant companies:

ONE Future Member Company	Year Joined
Antero Resources	2018
*Apache Corporation	2014
Arsenal Resources	2022
Ascent Resources	2019
Atmos Energy	2020
BHE Pipeline Group	2018
BKV Corporation	2021
Black Bear	2022
Black Hills Energy	2021
Blue Racer Midstream	2021
Boardwalk Pipelines	2019
Caerus Oil and Gas	2020
ConEdison	2021
Crestwood	2020
Dominion Energy	2018
DTE Energy	2021
DT Midstream	2021
Duke Energy	2020
Enbridge	2020
Encino Energy	2020
Enstor	2021
EQT Corporation	2018
Equitrans Midstream	2019
Flywheel Energy	2021
Forge Energy	2022
*Hess Corporation	2014
Jonah Energy	2021
*Kinder Morgan	2014
Kinetik	2020
National Fuel	2021
*National Grid	2014
New Jersey Natural Gas	2018
NiSource	2022

Northeast Natural Energy	2021
NW Natural	2020
ONE Gas	2020
ONEOK	2020
Roanoke Gas	2021
Sheridan Production	2021
*Southern Company Gas	2014
Southern Star	2020
*Southwestern Energy	2014
Spire	2021
Summit Utilities	2016
Targa	2021
TC Energy	2016
Terra Energy Partners	2021
UGI	2021
WBI Energy	2022
Western Midstream	2022
West Texas Gas	2021
WhiteWater Midstream	2022
Williams	2019
Xcel Energy	2020

* Represents the founding ONE Future Member Companies.

**Formerly called "EagleClaw Midstream"

ONE Future also thanks the following companies contributing to this protocol:

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AECOM

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ONE Future Member Companies

Antero Resources
Apache
Arsenal Resources
Ascent Resources
Atmos energy — Your natural gas company
BHE Pipeline Group
BKV
Black Bear Transmission
Black Hills Energy Ready
BlueRacer Midstream
Boardwalk Pipelines
Caerus Operating LLC
conEdison
Crestwood
Dominion Energy
DT Midstream
DTE
Duke Energy
Enbridge — Life Takes Energy
Encino Acquisition Partners
Enstor
EQT
equitrans Midstream
Flywheel Energy
Forge energy II
Hess
Jonah Energy LLC
Kinder Morgan
Kinetik
National Fuel
nationalgrid
New Jersey Natural Gas

EXECUTIVE SUMMARY

Who we are.

Our Nation's Energy Future Coalition, Inc. (ONE Future) is a non-profit trade group comprised of leading natural gas companies with operations in one or more of the five principal industry segments: (1) oil and natural gas production; (2) natural gas gathering and boosting; (3) natural gas processing; (4) natural gas transmission and storage; and (5) natural gas distribution.

Our mission.

ONE Future is focused on reducing methane emissions across the entire value chain by means of an innovative, flexible, and performance-based approach to the management of methane emissions.

Our approach.

ONE Future's approach begins with the establishment of a specific, measurable, and ambitious goal. By the year 2025, our member companies aim to achieve an average annual methane intensity across our collective operations that, if achieved by all operators across the natural gas value chain, would be equivalent to one percent or less of gross U.S. natural gas production. By orienting our activities toward a specific measurable outcome (a sustained low rate of methane emissions that is consistent with efficient operations), we focus on identifying the most cost-effective abatement opportunities.

Purpose of this document and Relationship with the EPA's Methane Challenge Program.

The U.S. Environmental Protection Agency (EPA) finalized the Methane Challenge Program[1] ONE Future Emissions Intensity Commitment (ONE Future Commitment) on August 3, 2016 and issued the initial Supplementary Technical Information (STI) document[2] for the ONE Future Commitment Option and has since issued an updated STI[3].

ONE Future strongly encourages, but does not require, its membership to participate in the Methane Challenge Program. ONE Future member companies that participate in the EPA Methane Challenge ONE Future Emissions Intensity Commitment (ONE Future Methane Challenge Partners) will sign a Partnership Agreement with EPA. These companies will report supplemental data to comprehensively track progress towards their commitments, including data that enables these firms to highlight emission reductions achieved through voluntary action. ONE Future Methane

[1] See EPA's Methane Challenge Website: https://www.epa.gov/natural-gas-star-program/methane-challenge-program
[2] http://onefuture.us/wp-content/uploads/2018/05/ONE-Future-Supplemental-Technical-Information.pdf
[3] https://www.epa.gov/sites/default/files/2016-08/documents/methanechallenge_one_future_supp_tech_info.pdf

Challenge Partners will quantify emissions and reductions, and report to the Methane Challenge Program using the protocols outlined in the STI.

All ONE Future companies, regardless of their participation in the EPA Methane Challenge Program, will use this Methane Emissions Estimation Protocol[4] to quantify and report their methane intensity. In addition, all ONE Future companies will need to execute an agreement with Our Nation's Energy Future (ONE Future) Coalition, Inc. and will work with other ONE Future members to achieve a sustained rate of methane emissions that is less than one percent of production across the entire natural gas value chain.

This protocol also defines how participating companies will estimate their average methane intensity and compare it to segment targets and the national goal of one percent methane intensity.

What is not contained in this document.

ONE Future published a review of the marginal abatement costs (MAC) of various methane emission abatement technologies and work practices for the natural gas industry (ICF, 2016). This MAC analysis had three goals: (1) to identify the emission sources that provide the greatest opportunity for methane emission reduction from the natural gas system, (2) to develop a comprehensive listing of known emission abatement technologies for each of the identified emission sources, and (3) to calculate the cost of deploying each emission abatement technology and to develop a MAC curve for these emission reductions. ONE Future used the findings of the MAC report to develop the segment-specific methane emission reduction goals outlined in this document that, when combined, will achieve a collective one percent (or less) methane intensity target in the most cost-effective manner.

The scope of this protocol is limited to methane intensity reporting and progress tracking. The specific emissions estimation methods to quantify and report the absolute emissions and reductions to the EPA's Methane Challenge program is specified in the EPA- issued STI. Specific program elements for company engagement in the EPA Methane Challenge Program, such as memorandums of understanding (MOU) between participating companies and the EPA, implementation plans, and specific data submission and management software to support emissions reporting, will be defined by EPA and are outside the scope of this document.

[4] ONE Future reserves the right to update the contents of this document at any time.

CHAPTER 1: INTRODUCTION

1.1 Background

Our Nation's Energy Future Coalition, Inc. (ONE Future) is a unique group of leading companies that collectively have operations in every segment of the natural gas value chain. An established non-profit 501(c)(6) trade group, ONE Future was formed to develop and demonstrate cost-effective policy and technical solutions to methane emission impact challenges associated with the production, gathering and boosting, processing, transmission, storage, and distribution of natural gas.

ONE Future's focus is on improving the management of methane (CH_4) emissions from the wellhead to the burner tip. By bringing together companies from every segment of the natural gas value chain, ONE Future aims to deploy innovative solutions to operational and policy challenges that will deliver better results to customers, increase value to shareholders, and improve the environment.

The ONE Future Coalition has established a specific, measurable, and ambitious goal: by the year 2025, member companies aim to achieve an average annual rate of CH_4 emissions across the value chain equivalent to one percent or less of gross U.S. natural gas production. This goal (emissions divided by gross production) is also called a "methane intensity". Stated differently, ONE Future aspires to demonstrate that through existing regulatory compliance and through additional voluntary actions, an industry-wide average methane intensity of one percent is achievable by 2025.

Why start with a goal of one percent? First, while this goal is ambitious, ONE Future believes that it is feasible using existing technology and practices. Secondly, peer-reviewed analyses suggest that for natural gas to provide greenhouse gas (GHG) reduction benefits compared to any other fossil fuel in any other end use application, the natural gas industry would have to achieve a methane emission rate of one percent or less across the natural gas value chain (IEA, 2012). Finally, by orienting ONE Future member activities toward a specific and measurable outcome (a sustained low rate of CH_4 emissions that is consistent with efficient operations), member companies will focus on identifying the most cost-effective abatement opportunities.

ONE Future's approach is goal-oriented but flexible. ONE Future believes that individual companies are best situated to choose how they can most cost-effectively and efficiently achieve their methane intensity goal – whether that is by deploying an innovative technology, modifying a work practice, or in some cases, replacing a high emissions asset with a low emissions asset. What is important is that member companies demonstrate progress toward the respective methane intensity targets.

The ONE Future framework calls for using this protocol to track company progress and program progress by computing methane intensities from natural gas systems at the national industry level, segment level,[5] and participating company level[6]. At the national level, ONE Future's overall program goal is to reduce CH_4 emissions to one percent of gross natural gas production by 2025. This is ONE Future's National Methane Intensity Target. The target is based on the U.S. EPA inventory of GHG emissions (GHGI) and U.S. Energy Information Administration (EIA) gas production data[7]. Calendar year 2012 emissions data were used when ONE Future announced its methane intensity goal (EPA, 2014). Based on 2012 emissions and production data, emissions from the natural gas segment were 1.44 percent of production[8]. These emissions can be broken down by industry segment as shown in Figure 1.1, where the emissions from each segment (Es) are divided by total gross production (GP).

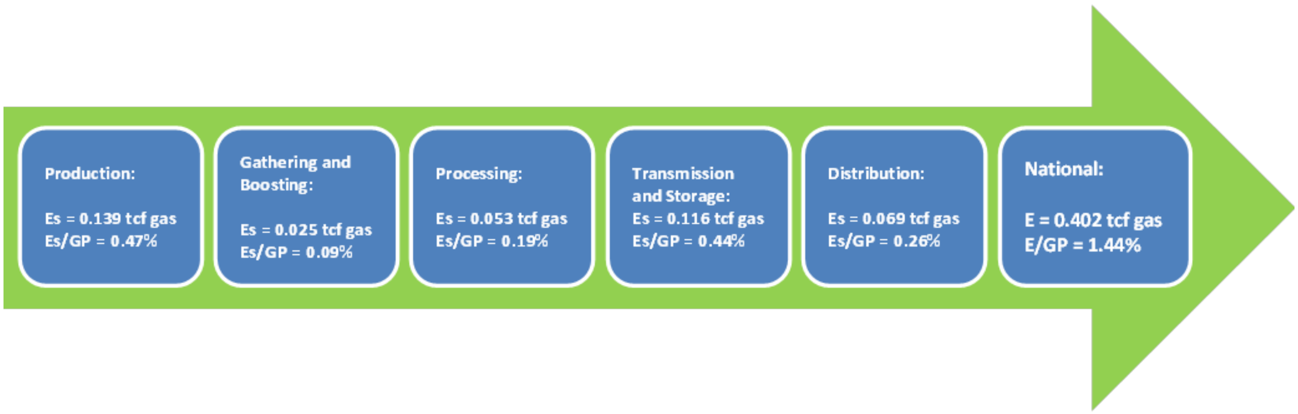

Figure 1.1. Illustration of 2012 Segment Methane Intensity Values and the 2012 National Methane Intensity Value.

The ONE Future goal is to demonstrate that participants along the natural gas value chain can reduce the 1.44% segment methane intensity shown in Figure 1.1 to one percent by 2025. The focus of this document is to explain how this goal will be established and tracked for participating companies within each industry segment. The first step is to translate the goal into Segment Methane Intensity Targets that represent targets for individual companies. While total emissions from each segment can be related to gross production to reflect the overall contribution from each segment, gross production is not a meaningful metric to calculate performance for the processing, transmission and storage, and distribution segments. The national level segment targets will be converted to Segment Methane Intensity Targets based on segment throughput parameters that individual companies can use to target and demonstrate their attainment of the goals (Section 2.4 explains this process in more detail). The reductions required from each segment will be based on a marginal abatement cost curve analysis of where the reductions can most effectively be achieved.

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[5] Segments are production, gathering and boosting, processing, transmission and storage, and distribution.
[6] Companies with assets in multiple segments may report all segments or may select segments to report.
[7] http://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_nus_a.htm
[8] The methane intensity for the entire natural gas segment for 2012 is 1.31% without accounting for co-allocation of emissions from associated gas originating at oil wells or lease condensates from gas wells. The 1.44% methane intensity target incorporates co-allocation from gas and oil wells and gas plant liquids and includes offshore gas production.

The Segment Methane Intensity Target will be used to track the progress of participant companies and to relate participant emissions to the segment and national level. The Segment Methane Intensity Targets do not add up to one percent because they are referenced to different throughput quantities in the denominator; however, they are developed in such a way that meeting these targets within each segment corresponds to meeting the overall ONE Future one percent National Methane Intensity Target.

The second step in meeting the ONE Future goal is to establish the procedures by which companies will measure and report their emissions, as well as their progress towards meeting the targets. The detailed procedure that companies use to compute their emissions largely follows the EPA's Greenhouse Gas Reporting Rule (GHGRP) or the national GHG Inventory prepared annually by EPA (referred to as the GHGI). The ONE Future framework significantly streamlines reporting requirements consistent with existing U.S. reporting requirements and therefore minimizes the additional burdens for participating companies.

This protocol document focuses on the necessary steps and processes to calculate emissions and targets as discussed in greater detail below.

1.2 ONE Future and the EPA Methane Challenge

The ONE Future Coalition remains an industry-led and operated organization, which operates independently, but which also collaborates with and can report under the EPA's Methane Challenge program. (Refer to Appendix A for an overview of the structure of the Methane Challenge Program.) ONE Future's participation augments and enhances the Methane Challenge program by providing a performance-based alternative to the EPA-administered "Best Management Practice" Commitment (BMP) option. The principles of the ONE Future option are as follows:

- **ONE Future's framework is performance-based and specific.** The end goal is to achieve a methane intensity of one percent or less of natural gas production. The goal is specific, measurable, and outcome-oriented in that the result is more important than how it is achieved.
- **ONE Future's approach is flexible.** ONE Future's approach is goal-oriented, which affords participants full flexibility in choosing where, when, and how to abate their methane intensity. This flexible approach is intended to prioritize emission reduction opportunities that are most cost-effective and efficiently deployed under corporate planning and strategy programs. In other words, a ONE Future participant incorporates serious corporate considerations such as capital and resource constraints in a low commodity pricing environment while also focusing on the environmental and operational benefits of lower CH_4 emissions.

ONE Future encourages all members to participate in the EPA Methane Challenge. However, ONE Future recognizes that a member company may not want to participate in the EPA Methane Challenge Program, but instead continue to participate in ONE Future's overall goal of achieving an industry-wide average methane intensity of one percent (emissions/gross production) by 2025.

The ONE Future Coalition is a recognized program partner of the EPA Methane Challenge Program. EPA's Methane Challenge aims to promote and support voluntary industry efforts to reduce CH_4 emission from natural gas systems. Under the EPA Methane Challenge Program, companies can be recognized as partners by opting to choose one or more commitment options, which include: (a) "Best Management Practice" Commitment Option or (b) "ONE Future Emissions Intensity" Commitment Option. ONE Future member companies opting to make the Methane Challenge ONE Future Emissions Intensity Commitment would sign a Partnership Agreement with EPA[9]. The Partnership Agreement will confirm each company's intention to join the EPA Methane Challenge Program and to provide relevant supplemental data to the EPA, as outlined in the Methane Challenge Program ONE Future Commitment Option Technical Document (MC Technical Document)[10], to reflect company-wide emissions volumes and demonstrate their methane emission reduction actions. The EPA would count the ONE Future Partners that opt to join Methane Challenge as partners in the EPA Methane Challenge Program and EPA would provide a reporting platform for transparently tracking company progress toward their Methane Challenge Program commitments.

The ONE Future companies not participating in the EPA's Methane Challenge will also use calculation methodologies that are in alignment with those that are presented in the MC Technical Document to compute their emissions, thereby ensuring consistency with the ONE Future Methane Challenge Partner companies. As noted in Section 2, these companies will compute their annual methane emissions for reporting as a member of ONE Future but they are not required compute and report their voluntary methane emission reductions. As a member of ONE Future, the companies track their methane emissions and report their progress to ONE Future and, at a minimum, include the data elements in Appendix B.

All ONE Future companies, regardless of their participation in the EPA's Methane Challenge Program will use this Methane Emissions Estimation Protocol[11] to quantify and report their methane intensity to the Executive Director of ONE Future by a timeline established by the ONE Future Board of Directors.

1.3 Methane Emissions Estimation Protocol

To enable diverse companies involved in different segments of the natural gas value chain to report CH_4 emissions in a manner that is both consistent and transparent, ONE Future has developed this Methane Emissions Estimation Protocol.[12] To minimize reporting burdens and provide consistent and transparent reporting, this protocol relies in large part on existing EPA estimation and reporting mechanisms – principally the U.S. EPA's GHGRP and the GHGI.

The protocol also defines the means by which participating companies will estimate their average methane intensity and compare it to their corresponding industry segment's average

[9] http://onefuture.us/wp-content/uploads/2018/05/ONE-Future-Commitment-Partnership-Agreement.pdf
[10] https://www.epa.gov/natural-gas-star-program/methane-challenge-program
[11] ONE Future reserves the right to update the contents of this document at any time.
[12] The scope of this protocol is limited to CH_4 emissions reporting and progress tracking. Specific program elements for company engagement in the EPA Methane Challenge Program, such as memorandums of understanding (MOU) between participating companies and the EPA, implementation plans, and specific data submission and management software to support emissions reporting will be defined by EPA and are outside the scope of this document.

methane intensity, as well as to the national goal set by ONE Future. A participating company meets its voluntary commitment by deploying appropriate abatement technologies or practices at any of its facilities to achieve an average annual methane intensity (expressed as a percentage of emissions over segment throughput on a mass of methane basis) that is less than or equal to the methane intensity target for its industry segment.

This protocol defines both the annual methane intensity calculation techniques, as well as the method by which annual results will be compared to the ONE Future segment goals. It is expected that this protocol will continue to evolve and be updated over the course of the multi-year ONE Future program. By using a written protocol, ONE Future participants aim to benchmark performance according to a common and uniform set of emission calculations and measurements so that our results are transparent and verifiable.

The written description of this methane intensity calculation and goal comparison is provided so that external stakeholders, whether the public, investors, other potential company participants, or regulators, can understand and validate the approach being used.

The document establishes guidelines for the following:

1) Calculating annual emissions from each participant using a combination of a) existing reported emissions inventories, b) supplements for any sources not covered in those approaches, and c) new measurements that may be performed by the companies;
2) Calculating emissions reductions that are not already tracked in the annual emissions in Step 1;
3) Calculating the resulting ONE Future participant methane intensities and aggregated segment methane intensities;
4) Comparing the resulting participant methane intensities to segment targets and national total performance; and, finally
5) Adjusting company methane intensities due to addition or sales of assets or updates to emissions methods.

1.4 Natural Gas Systems Value Chain

Approximately one-fourth of all energy used in the U.S. is from natural gas, which is comprised primarily of CH_4 (EIA, 2017). As illustrated in Figure 1.2, CH_4 emissions from Natural Gas Systems comprise approximately 2.0% of the total U.S. GHG emissions reported for calendar year 2012 (EPA, 2014)[13].

[13] 2012 data were presented in ONE Future's original protocol and 2012 is the basis for ONE Future's initial published methane intensity targets. ONE Future intends to revisit the Protocol document in 2021 and reserves the right to update information to reflect EPA's most current GHG emissions data at that time.

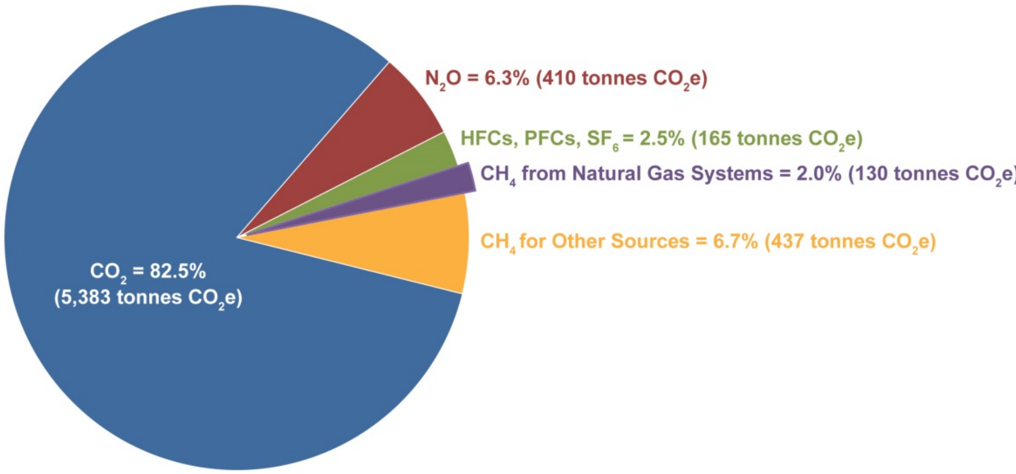

Figure 1.2. 2012 U.S. GHG Emissions by Pollutant (EPA, 2014)[14]

The natural gas industry produces and delivers natural gas to various residential, commercial, and industrial customers. The industry uses wells to produce natural gas existing in underground formations and then processes and compresses the gas and transports it to the customer. Transportation to the customer involves intrastate and interstate pipeline transportation, storage, and finally distribution of the gas to the customer through local distribution pipeline networks.

The generally accepted segments of the natural gas industry are:

- Production,
- Gathering and Boosting,
- Gas Processing,
- Transmission and Storage, and
- Distribution.

Each of these segments is illustrated in the flow chart for the industry in Figure 1.3 and is described in further detail below.

In the U.S. GHG Inventory[15] (abbreviated here as the GHGI), EPA addresses Natural Gas Systems separately from Petroleum Systems. The Production segment consists of wells producing natural gas (including oil wells producing gas), equipment located at the well site associated with natural gas production, and offshore gas production.

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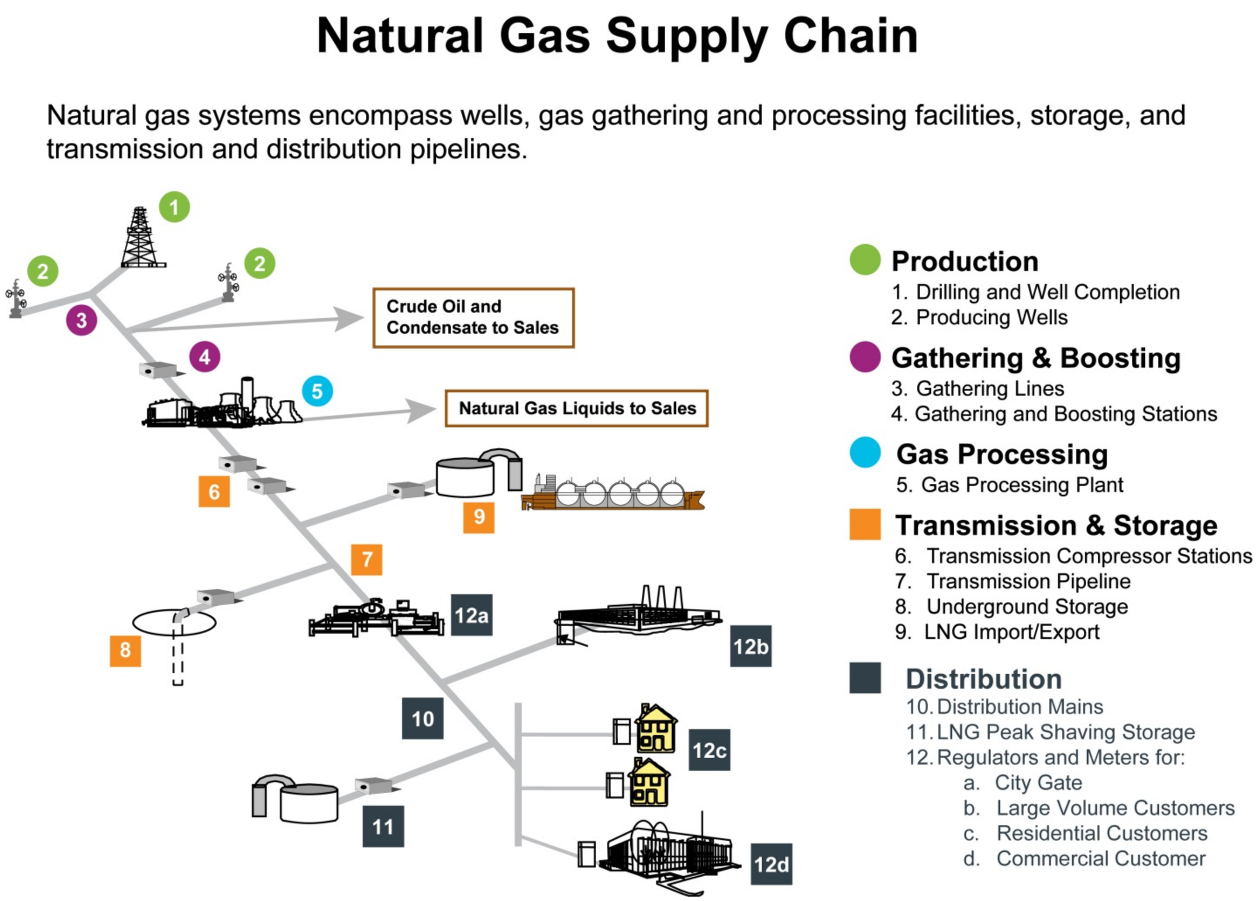
[14] tonnes = metric tons; CO_2e emissions are based on Global Warming Potential values from IPCC's Fourth Assessment Report (IPCC, 2007).

[15] The United States Environmental Protection Agency (EPA) prepares the official U.S. GHGI to comply with existing commitments under the United Nations Framework Convention on Climate Change (UNFCCC) by April 15th of each year.



Source: Adapted from American Gas Association and EPA Natural Gas STAR Program

Figure 1.3. Natural Gas Industry Segments

The EPA finalized a rule adding a separate industry segment covering Gathering and Boosting (separate from Production) in October 2015[16]. This rule enables EPA to collect new data on Gathering and Boosting emission sources such as gathering pipelines and gathering compressor stations beginning with the calendar year 2016 (CY2016) GHGRP reports. Data for this new segment were first available publicly in late 2017.

The Processing segment is made up of gas processing plants where natural gas liquids and other constituents are removed from raw gas, resulting in pipeline quality natural gas. Equipment associated with the gas processing segment includes all equipment inside a gas processing plant, such as: compressors, dehydrators, and acid gas removal units.

The Transmission and Storage segment is comprised of high pressure, large diameter pipelines that transport natural gas from production and processing to natural gas distribution systems or large-volume consumers such as power plants or chemical plants. This includes interstate and intrastate facilities. Storage facilities, such as underground storage in expended gas reservoirs or Liquefied Natural Gas (LNG) above-ground storage, are used by transmission companies to hold

[16] https://www.gpo.gov/fdsys/pkg/FR-2015-10-22/pdf/2015-25840.pdf

gas and allow for seasonal demand differences. LNG import/export terminals are also included in this segment. EPA combines Transmission and Storage in one segment since many of the storage facilities are owned and operated by the transmission companies, and since, in some cases the surface facilities (compression at underground storage, for example) are similar to other transmission facilities. For consistency the ONE Future program is aligned to the emission sources and types assigned to Transmission and Storage operations under the GHGI.

The Distribution segment covers natural gas pipelines that take the high-pressure gas from the transmission system, reduce the pressure, and distribute the gas through primarily underground mains and service lines to individual end users. This segment includes natural gas mains and services, metering and pressure regulating stations, and customer meters. It also includes some LNG peak shaving storage and underground storage facilities that are owned and operated by the distribution companies.

CHAPTER 2: GHG EMISSION ESTIMATION METHODS

2.1 Scope and Boundaries

On January 14, 2015, EPA announced its methane strategy to achieve methane reductions of 40-45% of 2012 levels by 2025. This document employs the methane data available from the April 2014 GHGI since the U.S.'s goals were based on the GHGI that was released on April 15, 2014. The emissions data provided in the April 2014 GHGI were for calendar year 2012. As a result, GHGI information used in developing ONE Future's initial segment methane intensities and natural gas industry methane intensity also reflect calendar-year 2012 data.

Consistent with ONE Future's goal of achieving CH_4 emissions that are less than or equal to one percent of gross production by the year 2025, only CH_4 emissions data will be quantified and tracked (CO_2 and N_2O emissions are excluded from the analysis). All ONE Future partners will report the minimum data elements as outlined in Appendix B to the ONE Future Executive Director. ONE Future participants will also compute their absolute CH_4 emissions data using estimation methodologies in alignment with those outlined in the MC Technical Document. In addition, ONE Future Methane Challenge Partners will report annually through a reporting platform developed by the EPA.

In general, the physical boundaries of ONE Future company assets included in this program are those of the U.S. natural gas value chain ranging from natural gas production through natural gas distribution. As noted in the MC Technical Document, ONE Future intends to use the same source, segment, and facility definitions as Subpart W, to the extent applicable[17] to compute the absolute CH_4 emissions. ONE Future will use each company's total absolute emissions data to determine its respective methane intensity. Methane intensity will be determined and reported at an appropriate business level or segment level of the company that includes the U.S. natural gas

[17] The ONE Future Commitment allows an alternate facility definition for Natural Gas Transmission Compression & Underground Natural Gas Storage facilities that do not report to Subpart W, which will be reported at an aggregated level by each partner company. See the MC Technical Document for details.

assets covered under the industry segment(s) chosen for the ONE Future program. The chosen industry segment(s) and its assets to be included under the ONE Future program will be specified in the company's ONE Future Implementation Plan to be submitted to the EPA[18].

Each of the following segments is included in the ONE Future program: Production, Gathering and Boosting, Processing, Transmission and Storage, and Distribution. End-use emissions associated with combustion of natural gas by the final consumers are not included in the ONE Future boundary (i.e., 40 CFR 98, Subpart NN emissions are excluded from the boundaries). End-use emissions are excluded as they are not controlled by ONE Future participants.

Assets that a company holds that are neither in the U.S. nor are not part of the U.S. natural gas value chain will not be included. Companies may purchase or sell assets during the ONE Future program, and those assets will be included or removed from the ONE Future inventory. Participant emissions and segment methane intensities will be compiled annually to track progress toward the program's goal. As a result, the annual updates will include changes resulting from participant company acquisitions or divestitures. In addition, upstream assets producing associated gas (gas co-produced from well sites that are primarily producing oil) will be included, but emissions from these assets will be allocated to each product (co-allocation techniques to exclude emissions associated with processing liquids co-produced with gas). Emissions from upstream well sites primarily producing natural gas, but which also co-produce some liquids, will also have emissions allocated to each main hydrocarbon product. The emissions allocation approach is described further in Appendix C and Appendix D.

Where CH_4 emissions are reported in terms of carbon dioxide equivalents (CO_2e), the global warming potential (GWP) values from the Intergovernmental Panel for Climate Change (IPCC) Fourth Assessment Report (AR4) are applied (for CH_4, the 100-year GWP value is 25[19]).

2.2 General Principles

The ONE Future framework is a performance- or methane intensity- (emissions divided by throughput) based structure. ONE Future's annual emission participant calculations are intended to be a supplementary extension of the reports that the participant companies already submit through the U.S. EPA's GHGRP. Throughput volumes reported by each Natural Gas segment for use in calculating methane intensities are noted in Section 2.4.

The GHGRP requires mandatory reporting of GHG emissions from facilities that emit 25,000 tonnes or more of CO_2 equivalent emissions per year. The GHGRP emission sources for the natural gas value chain are defined in Subpart W of the rule (40 CFR Part 98). Rather than substitute a new emissions calculation protocol, such as one using the latest available data in literature, ONE Future intends to primarily rely on the GHGRP techniques and approaches. ONE Future will supplement the GHGRP approach where it does not include all facilities or GHG emission sources for a particular segment.

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[18] https://www.epa.gov/natural-gas-star-program/methane-challenge-program

[19] ONE Future will employ newer GWPs once EPA updates their estimates to use the same.

The EPA also produces a national annual GHG inventory (GHGI) for all U.S. industries, including the natural gas industry. The latest version covers emissions from 1990 through 2020 (EPA, 2022). Each year, EPA uses national energy data, data on national agricultural activities, and other national statistics to provide a comprehensive accounting of total GHG emissions for all man-made sources in the U.S. In producing the GHGI, the EPA is advised by, but does not totally incorporate, the results of the GHGRP program. As the GHGI is the official U.S. inventory to the United Nations and accounts for emissions from the entire natural gas system, ONE Future will use the GHGI results as the benchmark for comparing ONE Future's segment methane intensities to the national segment methane intensity and for comparing ONE Future's overall progress to the national methane intensity of the natural gas industry.

As noted above, this document reflects 2012 methane emissions data from the GHGI published in April 2014 to establish the initial ONE Future Segment Methane Intensity Targets. In future years, as the U.S. EPA updates the GHGRP and the GHGI, ONE Future will make use of those updates to adjust and inform the ONE Future calculations described in this document.

2.3 Calculating Emissions for Member Companies

All ONE Future participants will compute absolute methane emissions using the specific methodologies prescribed in this Methane Emissions Estimation Protocol. ONE Future companies not participating in the EPA's Methane Challenge Program will use similar emission estimation methods as outlined in the MC Technical Document, except that for each emission source category, the company is not obligated to highlight or compute voluntary emission reductions. For example, for the Acid Gas Removal Vents source category, the company will use the GHGI segment-specific emission factors[20] to compute the emissions. Annually, the company will report its emissions to the ONE Future Executive Director as follows in Table 2.1.

Table 2.1. MC Technical Document Emission Data Reporting for Acid Gas Removal Units

Emission Source	Data Elements Collected via Facility-Level Reporting
Acid Gas Removal (AGR) vents	Actual count of AGR units
	Annual CH_4 Emissions (mt CH_4)

Tables B.1 through B.5 in Appendix B highlight the minimum data elements that will need to be reported to ONE Future as well as associated details.

2.4 Calculating Methane Intensities for Member Companies

Each ONE Future participant will estimate its methane intensities from all U.S.-based operations, including onshore and offshore production. Each company will compute its segment emissions (Ec), which will be normalized to methane intensity by dividing the company segment emissions by the total company throughput of natural gas for the segment (TPc). The corresponding

[20] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2014, Table A-136: 2014 Data and CH_4 Emissions [Mg] for the Natural Gas Processing Stage

throughput from these facilities reported to the Department of Energy's (DOE) Energy Information Administration (EIA) will be used to compute the methane intensities[21] (see Appendices C and D for detailed data).

For production companies, segment throughput equates to the volume of gas produced at wells. The volume of gas transferred from a gathering and boosting facility is the segment throughput for the Gathering and Boosting segment, since not all ONE Future participants with gathering and boosting operations have corresponding production operations. For natural gas processing companies, segment throughput refers to the volume of natural gas that has gone through a processing plant as reported to the EIA. For a natural gas transmission company, segment throughput refers to the volume of natural gas transported by the pipeline company. However, as explained in more detail in Appendix D, there is no single reported company-specific 'gas transported' values, so ONE Future has created an "estimated gas transported" for each transmission and storage company. ONE Future used the company's known and reported miles of transmission pipeline times a national ratio of gas transported to national pipeline miles. This estimated company throughput calculation is explained in more detail in Appendix D.4. For local distribution companies (LDCs), segment throughput[22] excludes sales to other LDCs to avoid double-counting and is weather-normalized for heat-sensitive residential and commercial loads using state-specific Heating Degree Day (HDD) values. Natural gas delivered to Industrial users, compressed natural gas (CNG) stations, and Power Generation facilities will not be weather-normalized. An example showing the adjustment to account for HDDs is provided in Appendix D.5.

Thus, a quantity of emissions is converted to emissions per gas throughput for each company (Ec/TPc), where both values are expressed in terms of the mass of CH_4. An example is provided for a hypothetical production company (see Example 1).

The emissions will be reported as an aggregate of all U.S. facilities within a segment (including onshore and offshore) owned or operated by the company and will be computed using the methodologies prescribed below.

EXAMPLE 1.

A Production company with U.S. operations in multiple basins has U.S. corporate-wide total emissions (Ec) of 1,200 tonnes of CH_4. The annual throughput (gross production) from all operations was 13,500,000 Mscf (TPc). Using a company-specific CH_4 fraction of 83.3% (molar volume) in natural gas and a methane density of 0.0192 kg/scf, the methane emissions equate to 215,914 tonnes of CH_4. Therefore, the company methane intensity = Ec/TPc = 1,200/215,914 = 0.56%

[21] Energy Information Administration, Annual Natural gas Gross Withdrawals and Production, http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_a.htm
[22] EIA publishes volumes reported by various companies in the Form 176 data response at http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RP4&f_sortby=&f_items=&f_year_start=&f_year_end=&f_show_compid=&f_fullscreen=

2.4.1 ONE Future Reporting

As noted earlier, ONE Future will track company progress and program progress by calculating methane intensities at the national, segment, and participant levels. At the national level, ONE Future's overall Program Goal and National Methane Intensity Target is to reduce CH_4 emissions by 2025 to one percent or less of gross natural gas production. However, while total national emissions from natural gas systems, as well as emissions from the Production and Gathering and Boosting segments can be related to gross production, gross production cannot be used as the methane intensity metric for the Processing, Transmission and Storage, and Distribution segments. At the segment level, segment emissions relative to segment throughput can be computed nationally as well as at the company level for each ONE Future participant. National segment throughputs are gathered primarily from EIA data, and are different for each segment of the natural gas value chain. Similar to computation at a Partner level, gross gas withdrawals minus repressuring as reported by the EIA are used as the national throughput value for both the Production and Gathering and Boosting segments. For the Processing segment, the national throughput equates to the total volume of natural gas processed as reported by EIA. For the Transmission segment, national throughput for the total volume of natural gas transported through transmission pipelines is not reported by EIA and is therefore estimated using techniques listed in Appendix D.6. For the Distribution segment, national throughput equates to the net volumes of gas delivered by the distribution companies and will be computed employing the EIA data[23]. For 2012, these throughput volumes for various segments are shown in Table 2.2.

A Segment Methane Intensity Target will be used as the Segment Performance Goal to track the progress of the participant companies and will also be used to relate participant emissions to the segment and national level. The following sub-sections describe the use of methane intensities to track a participant's performance and to relate participant emissions to the segment and national level.

Table 2.2. Summary of National Segment Throughputs for 2012

Segment	National Throughput Volume (Tcf natural gas)	National Throughput Mass (Gg CH_4)[a]	Average CH_4 Content (mol %)[b]
Production	29.5	471,716	83.3
Gathering and Boosting	29.5	471,716	83.3
Processing	17.5	292,477	87.0
Transmission and Storage	25.6	457,475	93.4
Distribution	13.3	238,704	93.4

[a] The conversion from throughput on a volume of natural gas basis to throughput on a mass of CH_4 basis applies a molar volume conversion of 1.198 gmol/scf based on ideal gas at 14.73 psi and 60 degrees F.
[b] Average methane contents for each segment are taken from EPA's 2012 National GHG Inventory Table A-131 and pages A-177 to A-178.

[23] https://www.eia.gov/naturalgas/ngqs/#?year1=2013&year2=2020&company=Name

The Executive Director of the ONE Future Coalition will publish the performance of ONE Future annually for the previous calendar year.

Within each industry segment, a weighted average Emission Rate per segment Throughput of the participant companies, represented in Equation 1 as:

$$\left(Average\ \frac{Ec}{TPc} = \frac{\sum Company\ emissions\ for\ all\ participants}{\sum Company\ throughputs\ for\ all\ participants}\right) \qquad \text{(Equation 1)}$$

will be calculated. This will serve as the Segment Performance for the calendar year and is illustrated in Figure 2.1.

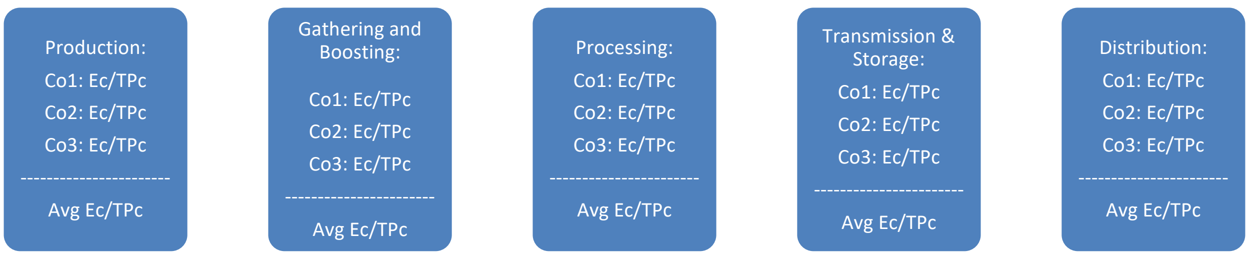

Figure 2.1. Illustration of Average Annual Segment Performance

2.5 Segment Methane Intensity Targets

Under the Methane Challenge Program's ONE Future methane intensity option, the participant company has the flexibility to implement reduction technologies and work-practices of its choice to achieve an average methane intensity[24] less than the goals outlined in Table 2.3.

The performance of each ONE Future company is determined by comparing the company's average methane intensity against the methane intensity goals for each segment (Segment Methane Intensity Targets) outlined in Table 2.3 for 2025. The Segment Methane Intensity Targets will be used to track the progress of the participant companies and will also be used to relate participant emissions to the segment and national level. Due to different segment throughputs, which are used in the denominator for computing the Segment Methane Intensity Goals, the values shown in Table 2.3 are not additive.

[24] Methane intensity is computed as net methane emissions from the participating Company divided by segment throughput for the participating Company.

Table 2.3. ONE Future Company's Segment Methane Intensity Goals (shown as a percent of segment throughput)

Industry Segment	Segment Methane Intensity[25] 2012	Methane Intensity Goals (percent of Segment throughput) 2025
Gas Production	0.47%	0.28%
Gas Gathering and Boosting	0.09%	0.08%
Gas Processing	0.30%	0.18%
Gas Transmission and Storage	0.45%	0.31%
Gas Distribution	0.52%	0.44%

Table 2.4 presents the ONE Future 'methane intensity' commitments on the basis of Gross Production. Collectively, ONE Future companies aim to achieve a goal whereby the rate of methane emissions across all industry segments is equivalent to or less than one percent of gross U.S. natural gas production in the year 2025. This is ONE Future's National Methane Intensity Target and is expressed as methane emissions per gross production for each segment of the natural gas value chain in Table 2.4. Each methane intensity value shown in Table 2.4 is calculated based on gross gas production, and therefore these methane intensities can be summed to result in an overall methane intensity value and compared against ONE Future's target.

Table 2.4. ONE Future Gross Production Segment Methane Intensity Values (methane emissions per gross production)[26]

Industry Segment	Methane Intensity Values (percent of Gross Production)	
	2012	2025[27]
Gas Production	0.47%	0.28%
Gas Gathering and Boosting	0.09%	0.08%
Gas Processing	0.19%	0.11%
Gas Transmission and Storage	0.44%	0.30%
Gas Distribution	0.26%	0.22%
Total	1.44%	1.00%

[25] ONE Future reserves the right to revise the segment targets and methods.

[26] The methane intensities computed using co-allocation based on energy to ensure emissions resulting from production of associated gas at oil wells, lease condensates and natural gas plant liquids (NGPL) are reasonably accounted. Without co-allocation, the 2012 methane intensity of the natural gas segment is 1.31%. Table 2.4 goals are collective goals of ONE Future and not for individual participant companies.

[27] For the purposes of Table 2.4 individual segment methane intensity targets were rounded to two significant digits.

2.6 Determination of Progress

The ONE Future participant companies individually and the ONE Future Coalition collectively will track their progress against the Segment Performance Targets as noted in Section 2.5. The Executive Director of ONE Future will compile participant data annually and develop the average annual segment methane intensities (emissions per segment throughputs), based on participant company annual reports, and scale the performance for participants in each segment to the annual national gross production. This provides the collective performance of all participants in each segment and enables comparison with the ONE Future national methane intensity goals.

2.6.1 Tracking Performance for ONE Future Participants

ONE Future participant companies will report methane intensities (Ec/TPc) annually to the ONE Future Coalition using this protocol. The performance of each participant company is determined by comparing the company's annual methane intensity (Ec/TPc) against the particular segment target methane intensity (Tsi) for 2025.

In addition, each participant company may also compute their *weighted average* methane intensity over particular *five-year* periods against the particular segment target methane intensity. This five-year weighted average can be useful for normalizing year-to-year operational variability.

For example, the following is a hypothetical illustration. Assume a production company X reports the emissions and production throughput values for five calendar years for all its U.S. onshore operations as noted in Table 2.5. The participant's methane intensity is calculated as the ratio of emissions to throughput for each year. A five-year weighted average methane intensity is calculated by summing the company's emissions over the five-year period and dividing by the sum of the company's segment (gross production for this example) throughput over the same period.

Table 2.5. Hypothetical Performance of ONE Future Participant in Production Segment

	Year 1	Year 2	Year 3	Year 4	Year 5	Totals
Total Participant Methane Emissions (Gg CH_4)	18	17.6	17.4	17.2	16.7	86.9
Production Throughput (Bcf)	370	390	410	390	420	1,980
Production Throughput (Gg CH_4 – assuming a CH_4 concentration of 85 mol% and density of 0.0192 kg/scf)	6,038	6,365	6,691	6,365	6,854	32,313
Methane Intensity (%)	0.30%	0.28%	0.26%	0.27%	0.24%	
Weighted Average (5 year) Methane Intensity						**0.27%**

The 5-year weighted average methane intensity for company X is 0.27%. The company's 5-year average methane intensity is less than the 2025 segment target of 0.28% from Table 2.3 and, therefore, company X is on track to meet the ONE Future Program Goal.

2.6.2 Tracking Performance for ONE Future Coalition

A mechanism is needed to translate the results from the ONE Future participant companies and to translate the Segment Methane Intensities (i.e., segment emissions divided by segment throughput) to the ONE Future national methane intensity target (national emissions from the natural gas value chain divided by gross natural gas production).

Overall progress toward ONE Future's reduction goal will be tracked by multiplying the average segment emission rates per segment throughputs for the participant companies ($SI_p = \frac{\sum E_c}{\sum TP_c}$), as developed from the participant company data, and shown in Example 2, by the ratio of the national segment throughput per national gross production (TPs/GP). This accomplishes two things:

> EXAMPLE 2.
>
> Assume the weighted average CH_4 intensity (as a function of throughput) of the Transmission and Storage Segment is equal to 0.51%. The 2012 Transmission and Storage segment throughput is 25.6 Tcf $(TPs)_{T\&S}$; while 2012 gross production equaled 29.5 Tcf (GP). Therefore, the ONE Future Segment Methane Intensity in terms of gross production is:
> 0.51% × 25.6/29.5 = 0.44%.

1. Scaling the Segment Methane Intensities calculated from the participant data to a national level (which assumes all companies in the natural gas value chain would produce similar results by implementing CH_4 mitigation methods); and
2. Converting the Segment Methane Intensities to a common gross production basis such that the segment methane intensities can be added to compare to the ONE Future national methane intensity target.

This is demonstrated in Equation 2 for the Transmission and Storage Segment. An example calculation is provided in Appendix D.6.

$$\frac{(E_S)_{T\&S}}{GP} = \left(\frac{\sum E_c}{\sum TP_c}\right)_{T\&S} \times \frac{(TP_S)_{T\&S}}{GP} \qquad \text{(Equation 2)}$$

Where:

$\frac{(E_S)_{T\&S}}{GP}$	=	ONE Future transmission and storage segment methane intensity (emissions per throughput) for the participant companies
$\left(\frac{\sum E_c}{\sum TP_c}\right)_{T\&S}$	=	Weighted average participant emissions per participant throughput for the Transmission and Storage segment
$(TP_S)_{T\&S}$	=	National Transmission and Storage segment Throughput
GP	=	National Gross Production

The ratios of national segment throughput to national gross production are used to convert the segment emissions to a common gross production basis (as illustrated in Equation 2) so that the segment emissions (Es/GP) can be added to arrive at an overall performance of ONE Future participants across all segments of the natural gas system. Additional details demonstrating the derivation of the methane intensity values are provided in Appendix C and D.

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Appendix A: Comparison of Two Options under the Methane Challenge Program

EPA's Natural Gas STAR Methane Challenge Program offers two options for participating companies to reduce CH_4 emissions from their operations: the Best Management Practice (BMP) option and the ONE Future Emissions Intensity Commitment Option. Figure A.1 illustrates key aspects of the two program options.

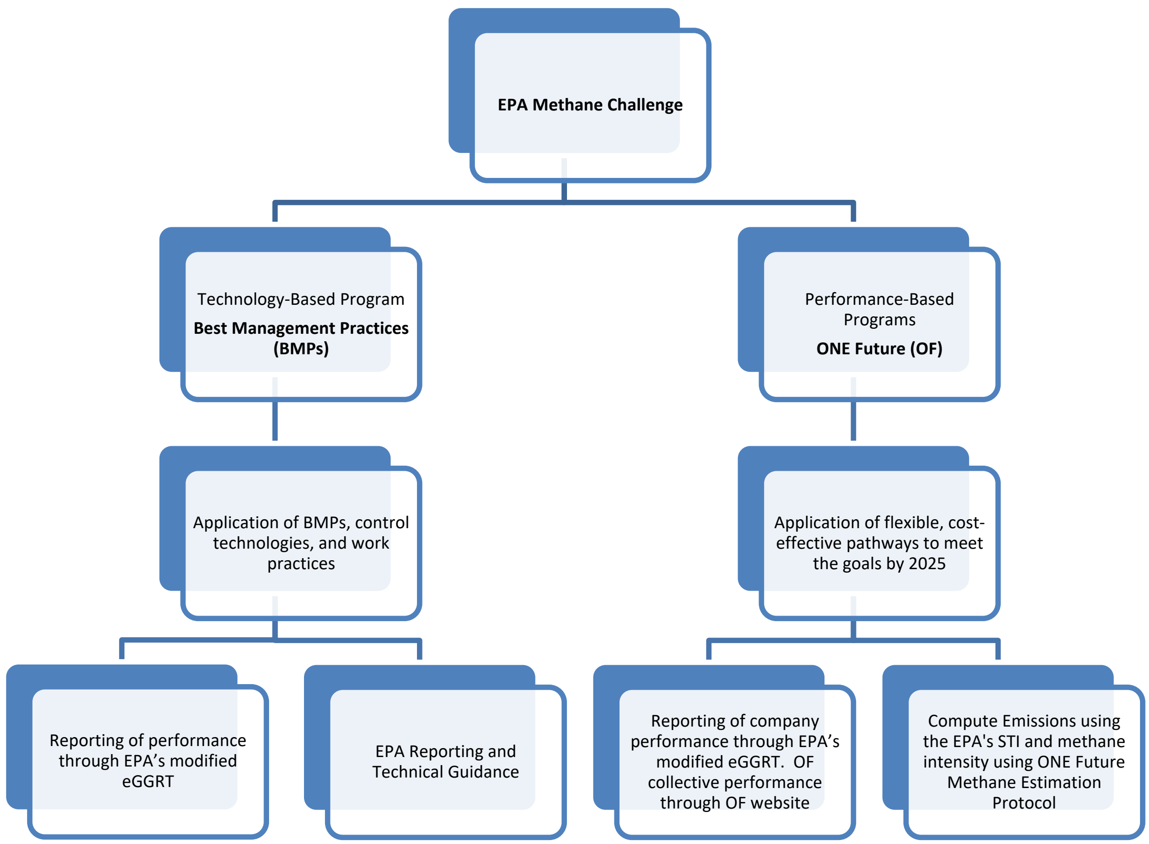

Figure A.1. EPA Methane Challenge Program

Appendix B: Annual Reporting Summaries

Each ONE Future company will report the following data elements annually to the ONE Future Executive Director following the calendar year being reported. ONE Future Methane Challenge Partners will submit the necessary reports as prescribed by the EPA Methane Challenge program. The following tables outline the data reporting requirements for each industry segment. The majority of these data elements align with the reporting requirements described in the Methane Challenge ONE Future Commitment Option Technical Document.[28]

The ONE Future report template is subject to change if additional data are required to be reported.

Table B.1. Production Facility Level Data Requirements

Emission Source	Activity Data	GHGRP Data	Annual Emissions, tonnes CH_4
Facility Throughput	Gross Gas Production for all wells in the reporting basin	Yes	
Exploration			
Well Drilling	Count of wells drilled	No	Annual CH_4 Emissions (Applies GHGI emission factor)
Well Completions with HF	Count of completions with HF	Yes	Annual CH_4 Emissions
	Count of wells that conduct flaring	Yes	
	Count of wells that have reduced emission completions	Yes	
Well Completions without HF	Count of completions that vented directly to the atmosphere without flaring	Yes	Annual CH_4 Emissions
	Count of completions with flaring	Yes	
Well Testing Venting and Flaring	Actual count of wells tested in a calendar year that vented emissions to the atmosphere	Yes	Annual CH_4 Emissions from venting
	Average number of days wells were tested that vented emissions to the atmosphere	Yes	
	Actual count of wells tested in a calendar year that flared emissions	Yes	Annual CH_4 Emissions from flaring
	Average number of days wells were tested that flared emissions	Yes	
Vented Sources			
Workovers with HF	Count of workovers with HF	Yes	Annual CH_4 Emissions
	Count of wells that conduct flaring	Yes	
	Count of wells that have reduced emission workovers	Yes	

[28] Based on the March 15, 2019 version of the Methane Challenge Technical Document. https://www.epa.gov/natural-gas-star-program/methane-challenge-program-one-future-commitment-option-technical-document

Emission Source	Activity Data	GHGRP Data	Annual Emissions, tonnes CH_4
Workovers without HF	Count of workovers that vented directly to the atmosphere without flaring	Yes	Annual CH_4 Emissions
	Count of workovers with flaring	Yes	
Liquids Unloading	Actual count of wells conducting liquids unloading without plunger lifts that are vented to the atmosphere	Yes	Annual CH_4 Emissions from wells without plunger lifts that are vented to the atmosphere
	Count of unloadings for all wells without plunger lifts	Yes	
	Actual count of wells conducting liquids unloading with plunger lifts that are vented to the atmosphere	Yes	Annual CH_4 Emissions from wells with plunger lift that are vented to the atmosphere
	Count of unloadings for all wells with plunger lifts	Yes	
Pneumatic Devices	Count of high bleed pneumatic controllers	Yes	Annual CH_4 Emissions
	Count of intermittent bleed pneumatic controllers	Yes	Annual CH_4 Emissions
	Count of low bleed pneumatic controllers	Yes	Annual CH_4 Emissions
Pneumatic Pumps	Count of pneumatic pumps	Yes	Annual CH_4 Emissions
Dehydrator Vents	Count of dehydrators > 0.4 MMscfd	Yes	
	Count of dehydrators < 0.4 MMscfd	Yes	
	Count of desiccant dehydrators	Yes	
	Count of Dehydrators venting to flare or regenerator firebox/fire tubes	Yes	Annual CH_4 emissions from dehydrators venting to a flare or regenerator firebox/fire tubes
	Count of dehydrators vented to vapor recovery units	Yes	Annual CH_4 emissions from all dehydrators that were not vented to a flare or regenerator firebox/fire tubes
Storage Tanks (Fixed Roof) Using Calculation Methods 1 & 2	Total volume of oil sent to tanks from all gas-liquid separators or non-separator equipment or wells flowing directly to atmospheric tanks with oil throughput ≥ 10 barrels/day (bbl/day)	Yes	Annual CH_4 Emissions
	Number of wells sending oil to gas-liquid separators or wells flowing directly to atmospheric tanks at ≥10 bbl/day	Yes	
	Actual count of atmospheric tanks	Yes	
	Count of tanks that control emissions with vapor recovery systems	Yes	Annual CH_4 emissions from tanks with vapor recovery systems
	Count of tanks that vented directly to the atmosphere	Yes	Annual CH_4 emissions from venting
	Count of tanks with flaring emission control measures	Yes	Annual CH_4 emissions from flaring
	Count of gas-liquid separators whose liquid dump valves did not close properly	Yes	Annual CH_4 emissions from improperly functioning dump valves

Emission Source	Activity Data	GHGRP Data	Annual Emissions, tonnes CH_4
Storage Tanks (Fixed Roof) Using Calculation Method 3	The total annual oil/condensate throughput that is sent to all atmospheric tanks in the basin, in barrels	Yes	Annual CH_4 Emissions
	Count of wells with gas-liquid separators	Yes	
	Count of wells without gas-liquid separators	Yes	
	Actual count of atmospheric tanks	Yes	
	Count of tanks that did not control emissions with flares	Yes	Annual CH_4 Emissions from tanks without flares
	Count of tanks that vented directly to the atmosphere	No	Annual CH_4 Emissions from venting
	Count of tanks with flaring emission control measures	Yes	Annual CH_4 Emissions from flaring
Floating Roof Tanks	Count of floating roof tanks	No	Annual CH_4 Emissions (Applies GHGI emission factor)
Associated Gas Venting and Flaring	Volume of oil produced during venting/flaring (bbls)	Yes	
	Volume of associated gas sent to sales (scf)	Yes	
	Actual count of wells venting associated gas	Yes	Annual CH_4 Emissions from venting
	Actual count of wells flaring associated gas	Yes	Annual CH_4 Emissions from flaring
Fugitive Sources			
Equipment Leaks	Count of each major equipment type	Yes	Total fugitive emissions calculated using population counts
	Number of each surveyed component type identified as leaking	Yes for OOOOa facilities	Total fugitive emissions calculated using fugitive surveys and leaker emission factors
Centrifugal Compressors	Number of centrifugal compressors with wet seal oil degassing vents	Yes	Annual CH_4 Emissions
	Number of centrifugal compressors with dry seals	No	Annual CH_4 Emissions (Applies GHGI emission factor)
Reciprocating Compressors	Number of reciprocating compressors	Yes	Annual CH_4 Emissions
Routine Maintenance			
Blowdowns	Count of vessels	No	Annual CH_4 Emissions (Applies GHGI emission factor)
	Count of compressors	No	Annual CH_4 Emissions (Applies GHGI emission factor)
Compressor Starts	Count of compressors	No	Annual CH_4 Emissions (Applies GHGI emission factor)
Pressure Relief Valves	Count of PRVs	No	Annual CH_4 Emissions (Applies GHGI emission factor)

Emission Source	Activity Data	GHGRP Data	Annual Emissions, tonnes CH_4
Combustion Sources			
Small Internal and External combustion sources	Actual count of external fuel combustion units with a rated heat capacity ≤ 5 MMBtu/hr PLUS internal fuel combustion units that are not compressor-drivers, with a rated heat capacity to ≤ 1 MMBtu/hr	Yes	
Large Internal Combustion Sources	Actual count of internal fuel combustion units that are not compressor-drivers, with a rated heat capacity >1 million Btu per hour	Yes	Annual CH_4 Emissions for internal fuel combustion units that are not compressor-drivers, with a rated heat capacity > 1 million Btu per hour
Internal Combustion Sources (Compressor Drivers)	Fuel usage and fuel heating value activity data for rich-burn engines, lean-burn engines, and turbines. If available (optional), direct measurement data of combustion exhaust methane emissions from stack tests performed on rich-burn engines, lean-burn engines, and turbines	No	Three (3) Options Option 1. Emission Factor only: Annual CH_4 Emissions for internal fuel combustion units of any heat capacity that are compressor-drivers (Applies AP-42 combustion exhaust methane emission factor, fuel use and fuel heating value) Option 2. Combination of Emission Factor and Methane Stack Test Measurements: Annual CH_4 Emissions for internal fuel combustion units of any heat capacity that are compressor-drivers (Applies AP-42 combustion exhaust methane emission factor for drivers not stack tested for methane combined with stack test measurements for all the other drivers stack tested for methane) Option 3. Methane Stack Test Measurements only: Annual CH_4 Emissions for internal fuel combustion units of any heat capacity that are compressor-drivers (Stack test measurements for all drivers tested for methane. This option is only used if all drivers have been tested for methane during the year.)
Large External Combustion Sources	Actual count of external fuel combustion units with a rated heat capacity > 5 million Btu per hour	Yes	Annual CH_4 Emissions for external fuel combustion units with a rated heat capacity > 5 million Btu per hour
Flares	Count of flare stacks	Yes	Annual CH_4 Emissions

Table B.2. Gathering and Boosting Facility Level Data Requirements

Emission Source	Activity Data	GHGRP Data	Annual Emissions, tonnes CH_4
Facility Throughput	Quantity of gas received at the facility, Mscf	Yes	
	Quantity of gas transferred from the facility, Mscf	Yes	
Vented Sources			
Pneumatic Devices	Count of high bleed pneumatic controllers	Yes	Annual CH_4 Emissions
	Count of intermittent bleed pneumatic controllers	Yes	Annual CH_4 Emissions
	Count of low bleed pneumatic controllers	Yes	Annual CH_4 Emissions
Pneumatic Pumps	Count of pneumatic pumps	Yes	Annual CH_4 Emissions
Dehydrator Vents	Count of dehydrators > 0.4 MMscfd	Yes	
	Count of dehydrators < 0.4 MMscfd	Yes	
	Count of desiccant dehydrators	Yes	
	Count of Dehydrators venting to flare or regenerator firebox/fire tubes	Yes	Annual CH_4 emissions from dehydrators venting to a flare or regenerator firebox/fire tubes
	Count of dehydrators vented to vapor recovery units	Yes	Annual CH_4 Emissions from all dehydrators that were not vented to a flare or regenerator firebox/fire tubes
Storage Tanks (Fixed Roof) Using Calculation Methods 1 & 2	Total volume of oil sent to tanks from all gas-liquid separators or gathering and boosting non-separator equipment or wells flowing directly to atmospheric tanks with oil throughput ≥ 10 barrels/day (bbl/day)	Yes	Annual CH_4 Emissions
	Number of wells sending oil to gas-liquid separators or wells flowing directly to atmospheric tanks at ≥10 bbl/day	Yes	
	Actual count of atmospheric tanks	Yes	
	Count of tanks that control emissions with vapor recovery systems	Yes	Annual CH_4 emissions from tanks with vapor recovery systems
	Count of tanks that vented directly to the atmosphere	Yes	Annual CH_4 emissions from venting
	Count of tanks with flaring emission control measures	Yes	Annual CH_4 emissions from flaring
	Count of gas-liquid separators whose liquid dump valves did not close properly	Yes	Annual CH_4 emissions from improperly functioning dump valves
Storage Tanks (Fixed Roof) Using Calculation Method 3	The total annual oil/condensate throughput that is sent to all atmospheric tanks in the basin, (bbls)	Yes	Annual CH_4 Emissions
	Count of wells with gas-liquid separators	Yes	
	Count of wells without gas-liquid separators	Yes	
	Actual count of atmospheric tanks	Yes	

Emission Source	Activity Data	GHGRP Data	Annual Emissions, tonnes CH_4
Storage Tanks (Fixed Roof) Using Calculation Method 3, Continued	Count of tanks that did not control emissions with flares	Yes	Annual CH_4 Emissions from tanks without flares
	Count of tanks that vented directly to the atmosphere	No	Annual CH_4 Emissions from venting
	Count of tanks with flaring emission control measures	Yes	Annual CH_4 Emissions from flaring
Floating Roof Tanks	Count of floating roof tanks	No	Annual CH_4 Emissions (Applies GHGI emission factor)
Fugitive Sources			
Equipment Leaks	Count of each major equipment type	Yes	Total fugitive emissions calculated using population counts
	Number of each surveyed component type identified as leaking	Yes for OOOOa facilities	Total fugitive emissions calculated using fugitive surveys and leaker emission factors
Equipment Leaks – Gathering Pipelines	Miles of cast iron gathering pipelines	Yes	Annual CH_4 Emissions
	Miles of protected steel gathering pipelines	Yes	Annual CH_4 Emissions
	Miles of unprotected steel gathering pipelines	Yes	Annual CH_4 Emissions
	Miles of plastic/composite gathering pipelines	Yes	Annual CH_4 Emissions
Centrifugal Compressors	Number of centrifugal compressors with wet seal oil degassing vents	Yes	Annual CH_4 Emissions
	Number of centrifugal compressors with dry seals	No	Annual CH_4 Emissions (Applies GHGI emission factor)
Reciprocating Compressors	Number of reciprocating compressors	Yes	Annual CH_4 Emissions
Routine Maintenance and Upsets			
Blowdown Vent Stacks	Count of blowdowns by equipment type	Yes	Annual emissions by equipment or event type
		Yes	Annual emissions calculated by flow meter
Mishaps (Pipeline Dig-ins)	Miles of gathering pipeline	No	Annual CH_4 Emissions (Applies GHGI emission factor)
Combustion Sources			
Small Internal and External combustion sources	Actual count of external fuel combustion units with a rated heat capacity ≤ 5 MMBtu/hr PLUS internal fuel combustion units that are not compressor-drivers, with a rated heat capacity to ≤ 1 MMBtu/hr	Yes	
Large Internal Combustion Sources	Actual count of internal fuel combustion units that are not compressor-drivers, with a rated heat capacity >1 million Btu per hour	Yes	Annual CH_4 Emissions for internal fuel combustion units that are not compressor-drivers, with a rated heat capacity > 1 million Btu per hour

Emission Source	Activity Data	GHGRP Data	Annual Emissions, tonnes CH_4
Internal Combustion Sources (Compressor Drivers)	Fuel usage and fuel heating value activity data for rich-burn engines, lean-burn engines, and turbines. If available (optional), direct measurement data of combustion exhaust methane emissions from stack tests performed on rich-burn engines, lean-burn engines, and turbines	No	<u>Three (3) Options</u> Option 1. Emission Factor only: Annual CH_4 Emissions for internal fuel combustion units of any heat capacity that are compressor-drivers (Applies AP-42 combustion exhaust methane emission factor, fuel use and fuel heating value) Option 2. Combination of Emission Factor and Methane Stack Test Measurements: Annual CH_4 Emissions for internal fuel combustion units of any heat capacity that are compressor-drivers (Applies AP-42 combustion exhaust methane emission factor for drivers not stack tested for methane combined with stack test measurements for all the other drivers stack tested for methane) Option 3. Methane Stack Test Measurements only: Annual CH_4 Emissions for internal fuel combustion units of any heat capacity that are compressor-drivers (Stack test measurements for all drivers tested for methane. This option is only used if all drivers have been tested for methane during the year.)
Large External Combustion Sources	Actual count of external fuel combustion units with a rated heat capacity > 5 million Btu per hour	Yes	Annual CH_4 Emissions for external fuel combustion units with a rated heat capacity > 5 million Btu per hour
Flares	Count of flare stacks	Yes	Annual CH_4 Emissions

Table B.3. Gas Processing Facility Data Requirements

Emission Source	Activity Data	GHGRP Data	Annual Emissions tonnes CH_4
Facility Throughput	Quantity of gas delivered to end users	Yes	
Vented Sources			
Pneumatic Devices	Count of high bleed pneumatic controllers	No	Annual CH_4 Emissions (Applies emission factor)
	Count of intermittent bleed pneumatic controllers	No	Annual CH_4 Emissions (Applies emission factor)
	Count of low bleed pneumatic controllers	No	Annual CH_4 Emissions (Applies emission factor)
Dehydrator Vents	Count of dehydrators > 0.4 MMscfd	Yes	
	Count of dehydrators < 0.4 MMscfd	Yes	
	Count of desiccant dehydrators	Yes	
	Count of Dehydrators venting to Flare or regenerator firebox/fire tubes	Yes	Annual CH_4 emissions from dehydrators venting to a flare or regenerator firebox/fire tubes
	Count of dehydrators vented to Vapor Recovery Units	Yes	Annual CH_4 emissions from all dehydrators that were not vented to a flare or regenerator firebox/fire tubes
Acid Gas Removal Units	Count of AGR Units	No	Annual CH_4 Emissions (Applies GHGI emission factor)
Fugitive Sources			
Equipment Leaks	Number of each surveyed component type identified as leaking	Yes for OOOOa facilities	Total fugitive emissions calculated using fugitive surveys and leaker emission factors
Centrifugal Compressors	Number of centrifugal compressors with wet seals	Yes	Annual CH_4 emissions vented to the atmosphere (applies GHGI emission factor to dry seal compressors)
	Number of centrifugal compressors with dry seals	Yes	
	Count routed to combustion	No	
	Count of manifolded groups	Yes	
	Count routed to flare	Yes	
	Count routed to vapor recovery	Yes	
	Count of compressors using the alternate method	No	Annual CH_4 Emissions
Reciprocating Compressors	Count of compressors with rod packing vented to atmosphere	Yes	Annual CH_4 emissions vented to the atmosphere from isolation valves, blowdown valves, and rod packing (including estimated fraction of CH_4 from manifolded compressor sources)
	Count of manifold groups	No	
	Count of compressor isolation valves w/control	No	
	Count of compressors blowdown valves w/control	No	
	Count of compressor rod packing w/control	No	
	Count of compressors using the alternate method	No	Annual CH_4 Emissions
Routine Maintenance			
Blowdown Vent Stacks	Count of blowdowns by equipment type	Yes	Annual CH_4 emissions by equipment or event type
		Yes	Annual CH_4 emissions calculated by flow meter

Emission Source	Activity Data	GHGRP Data	Annual Emissions tonnes CH_4
Combustion Sources			
Smaller Combustion Sources (not including engines and turbines)	Combustion emissions from smaller sources	No	Annual CH_4 Emissions
Internal Combustion Sources (engines and turbines that include compressor drivers)	Fuel usage and fuel heating value activity data for rich-burn engines, lean-burn engines, and turbines. If available (optional), direct measurement data of combustion exhaust methane emissions from stack tests performed on rich-burn engines, lean-burn engines, and turbines	No	Three (3) Options Option 1. Emission Factor only: Annual CH_4 Emissions for internal fuel combustion units of any heat capacity that are engines and turbines including those that are compressor-drivers (Applies AP-42 combustion exhaust methane emission factor, fuel use and fuel heating value) Option 2. Combination of Emission Factor and Methane Stack Test Measurements: Annual CH_4 Emissions for internal fuel combustion units of any heat capacity that are engines and turbines including those that are compressor-drivers (Applies AP-42 combustion exhaust methane emission factor for drivers not stack tested for methane combined with stack test measurements for all the other drivers stack tested for methane) Option 3. Methane Stack Test Measurements only: Annual CH_4 Emissions for internal fuel combustion units of any heat capacity that are engines and turbines including those that are compressor-drivers (Stack test measurements for all drivers tested for methane. This option is only used if all drivers have been tested for methane during the year.)
Flares	Count of flare stacks	Yes	Annual CH_4 Emissions

Table B.4. Transmission and Storage Facility[29] Level Data Requirements

Emission Source	Activity Data	GHGRP Data	Annual Emissions, tonnes CH_4
Facility Throughput	Miles of transmission pipeline (A surrogate quantity of gas transported will then be calculated by multiplying the provided miles by a national ratio of gas transported to total national pipeline miles)	No	
Vented Sources			
Pneumatic Devices (Transmission)	Count of high bleed pneumatic controllers	Yes	Annual CH_4 Emissions
	Count of intermittent bleed pneumatic controllers	Yes	Annual CH_4 Emissions
	Count of low bleed pneumatic controllers	Yes	Annual CH_4 Emissions
Pneumatic Devices (Storage)	Count of high bleed pneumatic controllers	Yes	Annual CH_4 Emissions
	Count of intermittent bleed pneumatic controllers	Yes	Annual CH_4 Emissions
	Count of low bleed pneumatic controllers	Yes	Annual CH_4 Emissions
Dehydrator Vents (Transmission)	Volume of gas dehydrated for transmission	No	Annual CH_4 Emissions (Applies GHGI emission factor)
Dehydrator Vents (Storage)	Volume of gas dehydrated for storage	No	Annual CH_4 Emissions (Applies GHGI emission factor)
Storage Tanks (Transmission)	Count of storage tank vent stacks with flares attached	Yes	
	Count of storage tank vent stacks without flares attached	Yes	
	Count of storage tank vent stacks with dump valve leakage direct to atmosphere	Yes	Annual CH_4 emissions from storage tank vent stacks with dump valve leakage venting gas directly to the atmosphere
	Count of storage tank vent stacks with flared dump valve leakage	Yes	Annual CH_4 emissions from storage tank vent stacks with flared dump valve leakage
	Count of storage tanks using the alternate calculation method	No	Annual CH_4 Emissions
Fugitive Sources			
Equipment Leaks (Compressor Stations)	Count of surveyed components identified as leaking	Yes	Annual CH_4 Emissions
	Indicate if the facility used the alternate method (company-based EF)	No	Annual CH_4 Emissions from fugitive sources

[29] The “facility” term for Transmission and Storage is aggregated at a **Pipeline Entity** level

Emission Source	Activity Data	GHGRP Data	Annual Emissions, tonnes CH_4
Equipment Leaks (Storage)	Count of surveyed components identified as leaking	Yes	Annual CH_4 Emissions from storage station and storage wellhead components
	Count of each emission source type	Yes	
	Indicate if the facility used the alternate method (company-based EF)	No	Annual CH_4 Emissions from fugitive sources
	Tank emissions from storage facilities	No	Annual CH_4 Emissions from tanks
Transmission Pipeline Leaks	Miles of pipeline	No	Annual CH_4 Emissions (Applies GHGI emission factor)
Centrifugal Compressors (Transmission)	Number of centrifugal compressors with wet seals	Yes	Annual CH_4 emissions vented to the atmosphere (applies GHGI emission factor to dry seal compressors)
	Number of centrifugal compressors with dry seals	Yes	
	Count routed to combustion	No	
	Count of manifolded groups	Yes	
	Count routed to flare	Yes	
	Count routed to vapor recovery	Yes	
	Count of compressors using the alternate method	No	Annual CH_4 Emissions
Centrifugal Compressors (Storage)	Number of centrifugal compressors with wet seals	Yes	Annual CH_4 emissions vented to the atmosphere (applies GHGI emission factor to dry seal compressors)
	Number of centrifugal compressors with dry seals	Yes	
	Count routed to combustion	No	
	Count of manifolded groups	Yes	
	Count of routed to flare	Yes	
	Count of routed to vapor recovery	Yes	
	Count of compressors using the alternate method	No	Annual CH_4 Emissions
Reciprocating Compressors (Transmission)	Count of compressors with rod packing vented to atmosphere	Yes	Annual CH_4 emissions vented to the atmosphere from isolation valves, blowdown valves, and rod packing (including estimated fraction of CH_4 from manifolded compressor sources)
	Count of manifold groups	No	
	Count of compressor isolation valves w/control	No	
	Count of compressors blowdown valves w/control	No	
	Count of compressor rod packing w/control	No	
	Count of compressors using the alternate method	No	Annual CH_4 Emissions

Emission Source	Activity Data	GHGRP Data	Annual Emissions, tonnes CH_4
Reciprocating Compressors (Storage)	Count of compressors with rod packing vented to atmosphere	Yes	Annual CH_4 emissions vented to the atmosphere from isolation valves, blowdown valves, and rod packing (including estimated fraction of CH_4 from manifolded compressor sources)
	Count of manifold groups	No	
	Count of compressor isolation valves w/control	No	
	Count of compressors blowdown valves w/control	No	
	Count of compressor rod packing w/control	No	
	Count of compressors using the alternate method	No	Annual CH_4 Emissions
Routine Maintenance			
Transmission Pipeline Blowdowns	Count of blowdowns	Yes	Annual CH_4 Emissions
Transmission Station Blowdowns	Count of blowdowns by equipment type	Yes	Annual emissions by equipment or event type
		Yes	Annual emissions calculated by flow meter
	Count of blowdowns using alternate calculation method	No	Annual CH_4 Emissions
Storage Station Venting	Count of Storage Stations	No	Annual CH_4 Emissions (Applies GHGI emission factor)
Combustion Sources			
Smaller Combustion Sources (not including engines and turbines) (Transmission)	Combustion emissions from smaller sources	No	Annual CH_4 Emissions
Smaller Combustion Sources (not including engines and turbines) (Storage)	Combustion emissions from smaller sources	No	Annual CH_4 Emissions
Internal Combustion Sources (engines and turbines that include compressor drivers at both Transmission and Storage facilities)	Fuel usage and fuel heating value activity data for rich-burn engines, lean-burn engines, and turbines. If available (optional), direct measurement data of combustion exhaust methane emissions from stack tests performed on rich-burn engines, lean-burn engines, and turbines	No	Three (3) Options Option 1. Emission Factor only: Annual CH_4 Emissions for internal fuel combustion units of any heat capacity that are engines and turbines including those that are compressor-drivers (Applies AP-42 combustion exhaust methane emission factor, fuel use and fuel heating value) Option 2. Combination of Emission Factor and Methane Stack Test Measurements: Annual CH_4 Emissions for internal fuel combustion units of any heat capacity that are engines and turbines including those that are compressor-drivers (Applies AP-42 combustion exhaust methane emission factor for drivers not stack tested for methane combined with stack test

Emission Source	Activity Data	GHGRP Data	Annual Emissions, tonnes CH_4
			measurements for all the other drivers stack tested for methane) Option 3. Methane Stack Test Measurements only: Annual CH_4 Emissions for internal fuel combustion units of any heat capacity that are engines and turbines including those that are compressor-drivers (Stack test measurements for all drivers tested for methane. This option is only used if all drivers have been tested for methane during the year.)
Flares (Transmission)	Count of flare stacks	Yes	Annual CH_4 Emissions
Flares (Storage)	Count of flare stacks	Yes	Annual CH_4 Emissions

Table B.5. Distribution Facility Level Data Requirements

Emission Source	Activity Data	GHGRP Data	Annual Emissions, tonnes CH_4
Facility Throughput	Quantity of gas delivered to end users weather-normalized for heat-sensitive residential and commercial load using state-specific Heating Degree Days (HDD) values	No	
Fugitive Sources			
Distribution Mains	Miles of cast iron mains	Yes	Annual CH_4 Emissions (Applies GHGI factor)
	Miles of unprotected steel mains	Yes	Annual CH_4 Emissions (Applies GHGI factor)
	Miles of protected steel mains	Yes	Annual CH_4 Emissions (Applies GHGI factor)
	Miles of plastic mains	Yes	Annual CH_4 Emissions (Applies GHGI factor)
	Miles of copper mains	No	Annual CH_4 Emissions (Applies GHGI factor)
	Miles of cast iron or unprotected steel mains with plastic liners or inserts	No	Annual CH_4 Emissions (Applies GHGI factor)
	Miles of ductile iron mains	No	Annual CH_4 Emissions (Applies GHGI factor)
	Miles of "other" [30] mains	No	Annual CH_4 Emissions (Applies GHGI factor)
Distribution Services	Count of unprotected steel services	Yes	Annual CH_4 Emissions (Applies GHGI factor)
	Count of protected steel services	Yes	Annual CH_4 Emissions (Applies GHGI factor)
	Count of plastic services	Yes	Annual CH_4 Emissions (Applies GHGI factor)
	Count of cast iron/wrought iron services	No	Annual CH_4 Emissions (Applies GHGI factors)
	Count of copper services	Yes	Annual CH_4 Emissions (Applies GHGI factor)
	Count of cast iron or unprotected steel services with plastic lines or inserts	No	Annual CH_4 Emissions (Applies GHGI factor)
	Count of ductile iron services	No	Annual CH_4 Emissions (Applies GHGI factor)
	Count of "other" [31] services	No	Annual CH_4 Emissions (Applies GHGI factor)
Above Grade Transmission-Distribution Transfer Stations	Actual count of above grade T-D transfer stations	Yes	Annual CH_4 Emissions
	Actual count of meter/regulator runs at above grade T-D transfer station facilities	Yes	
	Number of above grade T-D transfer stations surveyed	Yes	
	Number of meter/regulator runs at above grade T-D transfer stations surveyed	Yes	

[30] "Other" does not include unprotected steel mains, protected steel mains, plastic mains, cast iron mains, cast iron or unprotected steel mains with plastic liners or inserts, copper mains, or ductile iron mains.
[31] "Other" does not include unprotected steel services, protected steel services, plastic services, cast iron services, cast iron or unprotected steel services with plastic liners or inserts, copper services, or ductile iron services.

Emission Source	Activity Data	GHGRP Data	Annual Emissions, tonnes CH_4
Above Grade Transmission-Distribution Transfer Stations, Continued	Average time that meter/regulator runs were operational, in hours	Yes	Annual CH_4 Emissions
Below-grade Transmission-Distribution Transfer Stations	Actual count of below grade transmission-distribution transfer stations with inlet pressure > 300 psig)	Yes	Annual CH_4 Emissions
	Actual count of below grade transmission-distribution transfer station with inlet pressure 100 to 300 psig	Yes	
	Actual count of below grade transmission-distribution transfer station with inlet pressure < 100 psig	Yes	
	Average estimated time that the emission source type was operational	Yes	
Above-grade Metering-Regulating stations that are not T-D transfer stations	Actual count of above grade metering-regulating stations that are not T-D transfer stations	Yes	Annual CH_4 Emissions
	Actual count of meter/regulator runs at above grade metering-regulating stations that are not above grade T-D transfer stations	Yes	
	Average annual estimated time that each M/R run at above grade M/R stations that are not above grade T-D transfer stations was operational	Yes	
Below-grade Metering-Regulating stations	Actual count of below grade M-R Station with Inlet Pressure > 300 psig	Yes	Annual CH_4 Emissions
	Actual count of below grade M-R Station with Inlet Pressure 100 to 300 psig	Yes	
	Actual count of below grade M-R Station with Inlet Pressure < 100 psig	Yes	
	Average annual estimated time that the emission source type was operational	Yes	
Residential Meters	Number of outdoor meters	No	Annual CH_4 Emissions (Applies GHGI factor)
Industrial Meters	Number of industrial meters	No	Annual CH_4 Emissions (Applies GHGI factor)
Commercial Meters	Number of commercial meters	No	Annual CH_4 Emissions (Applies GHGI factor)
Odorizers	Number of odorizers	No	Annual CH_4 Emissions (Applies GTI OTD 7.7b factor)
Equipment Leaks (Storage)[32]	Count of surveyed components identified as leaking	Yes	Annual CH_4 Emissions from storage station and storage wellhead components
	Count of each emission source type	Yes	
	Indicate if the facility used the alternate method (company-based EF)	No	Annual CH_4 Emissions from fugitive sources
	Tank emissions from storage facilities	No	Annual CH_4 Emissions from tanks
Centrifugal Compressors (Storage)[32]	Number of centrifugal compressors with wet seals	Yes	

[32] For CY2022, underground natural gas storage and LNG storage facilities were able to be included with either the T&S segment or the Distribution segment depending on which segment they are physically located and operated. Refer to section D.5.1.

Emission Source	Activity Data	GHGRP Data	Annual Emissions, tonnes CH_4
	Number of centrifugal compressors with dry seals	Yes	Annual CH_4 emissions vented to the atmosphere (applies GHGI emission factor to dry seal compressors)
	Count routed to combustion	No	
	Count of manifolded groups	Yes	
	Count of routed to flare	Yes	
	Count of routed to vapor recovery	Yes	
	Count of compressors using the alternate method	No	Annual CH_4 Emissions
Reciprocating Compressors (Storage)[32]	Count of compressors with rod packing vented to atmosphere	Yes	Annual CH_4 emissions vented to the atmosphere from isolation valves, blowdown valves, and rod packing (including estimated fraction of CH_4 from manifolded compressor sources)
	Count of manifold groups	No	
	Count of compressor isolation valves w/control	No	
	Count of compressors blowdown valves w/control	No	
	Count of compressor rod packing w/control	No	
	Count of compressors using the alternate method	No	Annual CH_4 Emissions
Routine Maintenance / Upsets			
Pressure Relief Valves	Miles of distribution mains	No	Annual CH_4 Emissions (Applies GHGI factor)
Pipeline Blowdowns	Miles of distribution pipeline mains and services	No	Annual CH_4 Emissions (Applies GHGI factor)
Mishaps (Dig-ins, Pipeline Damages)	Miles of distribution pipeline mains and services	No	Annual CH_4 Emissions (Applies GHGI factor)
Storage Station Venting[32]	Count of Storage Stations	No	Annual CH_4 Emissions (Applies GHGI factor)
Combustion Sources			
Small Internal and External combustion sources	Actual count of external fuel combustion units with a rated heat capacity ≤ 5 MMBtu/hr PLUS internal fuel combustion units that are not compressor-drivers, with a rated heat capacity to ≤ 1 MMBtu/hr	Yes	
Large Internal Combustion Sources (Distribution; excluding storage facilities)	Actual count of internal fuel combustion units that are not compressor-drivers, with a rated heat capacity >1 million Btu per hour	Yes	Annual CH_4 Emissions for internal fuel combustion units that are not compressor-drivers, with a rated heat capacity > 1 million Btu per hour
	Actual count of internal fuel combustion units of any heat capacity that are compressor-drivers	Yes	Annual CH_4 Emissions for internal fuel combustion units of any heat capacity that are compressor-drivers
Large External Combustion Sources	Actual count of external fuel combustion units with a rated heat capacity > 5 million Btu per hour	Yes	Annual CH_4 Emissions for external fuel combustion units with a rated heat capacity > 5 million Btu per hour

Emission Source	Activity Data	GHGRP Data	Annual Emissions, tonnes CH_4
Internal Combustion Sources (engines and turbines that include compressor drivers at Storage facilities)[32]	Fuel usage and fuel heating value activity data for rich-burn engines, lean-burn engines, and turbines. If available (optional), direct measurement data of combustion exhaust methane emissions from stack tests performed on rich-burn engines, lean-burn engines, and turbines	No	Three (3) Options Option 1. Emission Factor only: Annual CH_4 Emissions for internal fuel combustion units of any heat capacity that are engines and turbines including compressor-drivers at storage facilities (Applies AP-42 combustion exhaust methane emission factor, fuel use and fuel heating value) Option 2. Combination of Emission Factor and Methane Stack Test Measurements: Annual CH_4 Emissions for internal fuel combustion units of any heat capacity that are engines and turbines including compressor-drivers at storage facilities (Applies AP-42 combustion exhaust methane emission factor for drivers not stack tested for methane combined with stack test measurements for all the other drivers stack tested for methane) Option 3. Methane Stack Test Measurements only: Annual CH_4 Emissions for internal fuel combustion units of any heat capacity that are engines and turbines including compressor-drivers at storage facilities (Stack test measurements for all drivers tested for methane. This option is only used if all drivers have been tested for methane during the year.)
Flares (Storage)[32]	Count of flare stacks	Yes	Annual CH_4 Emissions
Vented Sources			
Pneumatic Devices (Storage)[32]	Count of high bleed pneumatic controllers	Yes	Annual CH_4 Emissions
	Count of intermittent bleed pneumatic controllers	Yes	Annual CH_4 Emissions
	Count of low bleed pneumatic controllers	Yes	Annual CH_4 Emissions
Dehydrator Vents (Storage)[32]	Volume of gas dehydrated for storage	No	Annual CH_4 Emissions (Applies GHGI emission factor)

Appendix C: Derivation of 2012 National Methane Intensities

C.1 Methane Intensities

Figure C.1 provides a summary of methane intensity computation on a gross gas production (Es/GP) and throughput basis (Es/TPs) using 2012 data for each segment from the 2014 GHGI.

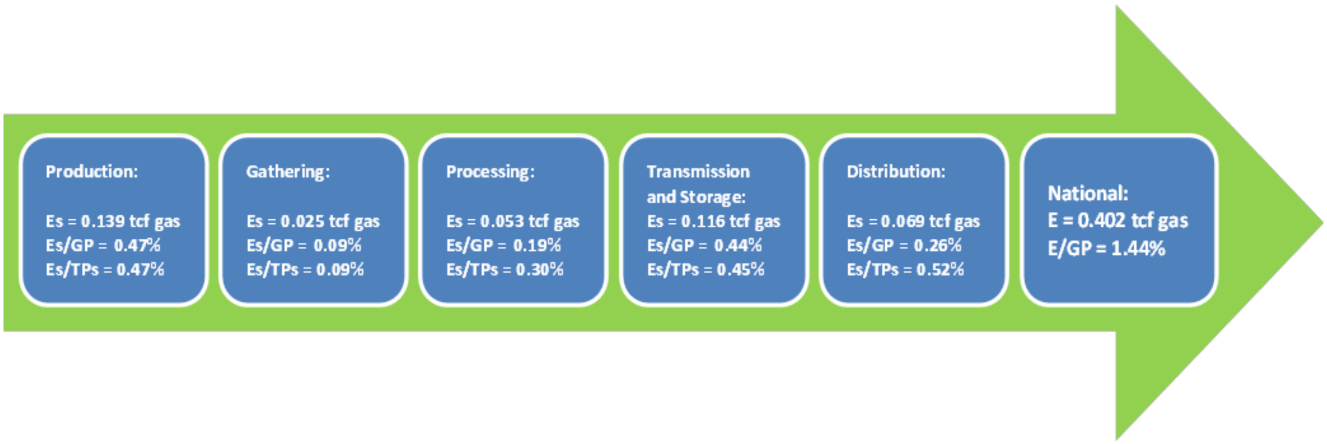

Figure C.1. Illustration of Segment Methane Intensity Targets and the National Methane Intensity Target (CY2012 Data from the 2014 GHGI are Shown)

C.1.1 Emissions per Gross Production

The emissions per gross production (E_s/GP) for each segment are calculated based on the ratio of emissions for each segment (Gg CH_4 from EPA's national GHG Inventory) and gross natural gas withdrawals (from Energy Information Administration[33] converted to Gg CH_4).

The gross gas production is represented by the gross natural gas withdrawals as reported by the Energy Information Administration (EIA).[33] Gross withdrawal is the full well stream volume, including all natural gas plant liquids and all non-hydrocarbon gases, excluding lease condensate. This volume, 29.5 Trillion cubic feet (Tcf) for 2012, is used in the denominator for all of the segment E_s/GP values. The E_s/GP is shown on a mass of CH_4 basis, which using the conversion factors shown in Equation C-1, results in 471,716 Gg CH_4 gross gas withdrawal.

As an example, the 2012 methane intensity calculation for the Transmission and Storage segment target is shown in Equation C-1.

$$\frac{E_S}{GP}_{T\&S} = \frac{2{,}071\ Gg\ CH_4}{29.5\ TCF\ gross\ production} \times \frac{Tcf\ gas}{10^{12}\ scf\ gas} \times \frac{scf\ gas}{1.198\ gmol\ gas} \times \frac{gmol\ Nat.Gas}{0.833\ gmol\ CH_4} \times$$

$$\frac{g\ ole\ CH_4}{16\ g\ CH_4} \times \frac{10^9\ g\ CH_4}{Gg\ CH_4} = 0.44\% \qquad \text{(Equation C-1)}$$

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[33] Energy Information Administration, 2012 Natural gas Gross Withdrawals and Production, http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_a.htm

Sources for the data used in the example equation above are summarized in Table C.1 below.

Table C.1. Data Sources for Values Shown in Equation C-1

Equation Value	Source of the Equation Term
2,071 Gg CH_4	2012 EPA National GHG Inventory, Table A-129 for transmission and storage.
29.5 Tcf Gross production	2012 Gross gas Withdrawals from Energy Information Administration (EIA).[33] This gas volume is used in the denominator for each of the segment E_s/GP ratios. Equivalent to 471,716 Gg CH_4.
1.198 gmol gas/scf gas	Gas molar volume based on 14.73 psi, 60 ºF
0.833 mol CH_4/mol gas for the production segment	2014 EPA National GHG Inventory Report, Table A-131, value for general sources, lower 48 states in 2012. This is needed to convert the volume of natural gas gross production to mass of CH_4. Composition data for the other industry segments is from the 2014 EPA National GHG Inventory Report, Annex 3, pages A177-178. These values are shown in Table C.2.
16 g CH_4/gmol CH_4	Molecular weight of CH_4

C.1.2 Emissions Per Segment Throughput

Segment methane intensities are used to track the progress of ONE Future companies and will also be used to relate ONE Future company emissions to the segment and national levels. The ratio of segment emissions per segment throughput uses the same segment emissions in the numerator but applies segment-specific throughput values in the denominator. Table C.2 shows the segment-specific values used in deriving the E_s/GP and E_s/TP_s values shown in Figure C.1. Figure C.2 illustrates the points in the natural gas value chain where these volumes are determined.

For the Production and Gathering and Boosting segments, the "segment throughput" is the same as the national gross production of natural gas, discussed earlier in Section C.1.1. However, for all other segments, the throughput is a smaller volume than gross gas production as illustrated in Figure C.2. For example, for the processing segment, only a portion of the gas goes through a gas processing plant; some gas goes directly to transmission.

EIA data are also used for the segment throughput values for Gas Processing, Transmission and Storage, and Distribution segments. For Gas Processing, EIA reports an annual volume of gas processed, representing the volume of natural gas that has gone through the processing plant, from EIA form 64A that is completed by natural gas processing plant operators.[34]

[34] http://www.eia.gov/dnav/ng/ng_prod_pp_a_EPG0_ygp_mmcf_a.htm

The throughput volume for Transmission and Storage on a national basis is the combination of the volume of dry gas production and net imports. Dry gas production represents consumer-grade natural gas and is equivalent to marketed gas production less extraction losses.[35] This assumes that all dry gas production is transported in transmission lines. Net imports represent the difference between imported natural gas and exported natural gas and include imports and exports by both pipeline and LNG. The volumes of gas imported and exported are reported to EIA by the U.S. Department of Energy.[36]

Table C.2. 2012 Segment Data for Emissions per Gross Throughput and Emissions per Segment Throughput

Segment	GHG Inventory 2012 Emissions		Segment CH_4 Fractions[37]	Segment Throughput Volumes	Source of Segment Throughput Volumes	Mass Ratio ($Gg\ CH_4/Gg\ CH_4$) E_s/GP	Volume Ratio (Tcf gas/Tcf gas) E_s/TP
	$Gg\ CH_4$[38]	Tcf Natural Gas	mol CH_4/mol natural gas	Tcf Natural Gas			
Production	2,215.6	0.139	0.833	29.5	EIA, gross gas withdrawals[33]	$\frac{2,215.6}{471,716} = 0.47\%$	$\frac{0.139}{29.5} = 0.47\%$
Gathering and Boosting	404.0	0.025	0.833	29.5	EIA, gross gas withdrawals[33]	$\frac{404}{471,716} = 0.09\%$	$\frac{0.025}{29.5} = 0.09\%$
Processing	891.2	0.053	0.870	17.5	EIA, Gas Processed[34]	$\frac{891.2}{471,716} = 0.19\%$	$\frac{0.053}{17.5} = 0.30\%$
Transmission and Storage	2,071.0	0.116	0.934	25.6	EIA, Dry gas production[33] + net gas imports[36]	$\frac{2,071}{471,716} = 0.44\%$	$\frac{0.116}{25.6} = 0.45\%$
Distribution	1,231.3	0.069	0.934	13.3	Gas delivered to consumers from EIA Form 176[22]	$\frac{1,231.3}{471,716} = 0.26\%$	$\frac{0.069}{13.3} = 0.52\%$
TOTAL	**6,813.1**	**0.402**				**1.44%**	**Not additive due to different denominators**

[35] EIA defines extraction losses as the reduction in the volume of natural gas due to removing natural gas liquids (ethane, propane, and ethane).
[36] Office of Fossil Energy, U.S. Dept. of Energy, "Natural Gas Imports and Exports"
[37] Composition data from the 2012 EPA Inventory, Annex 3, pages A177-178 and Table A-131, value for general gas, lower 48 states.
[38] Source Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012 (April 2014) EPA 430-R-14-003, Annex Tables. https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2012

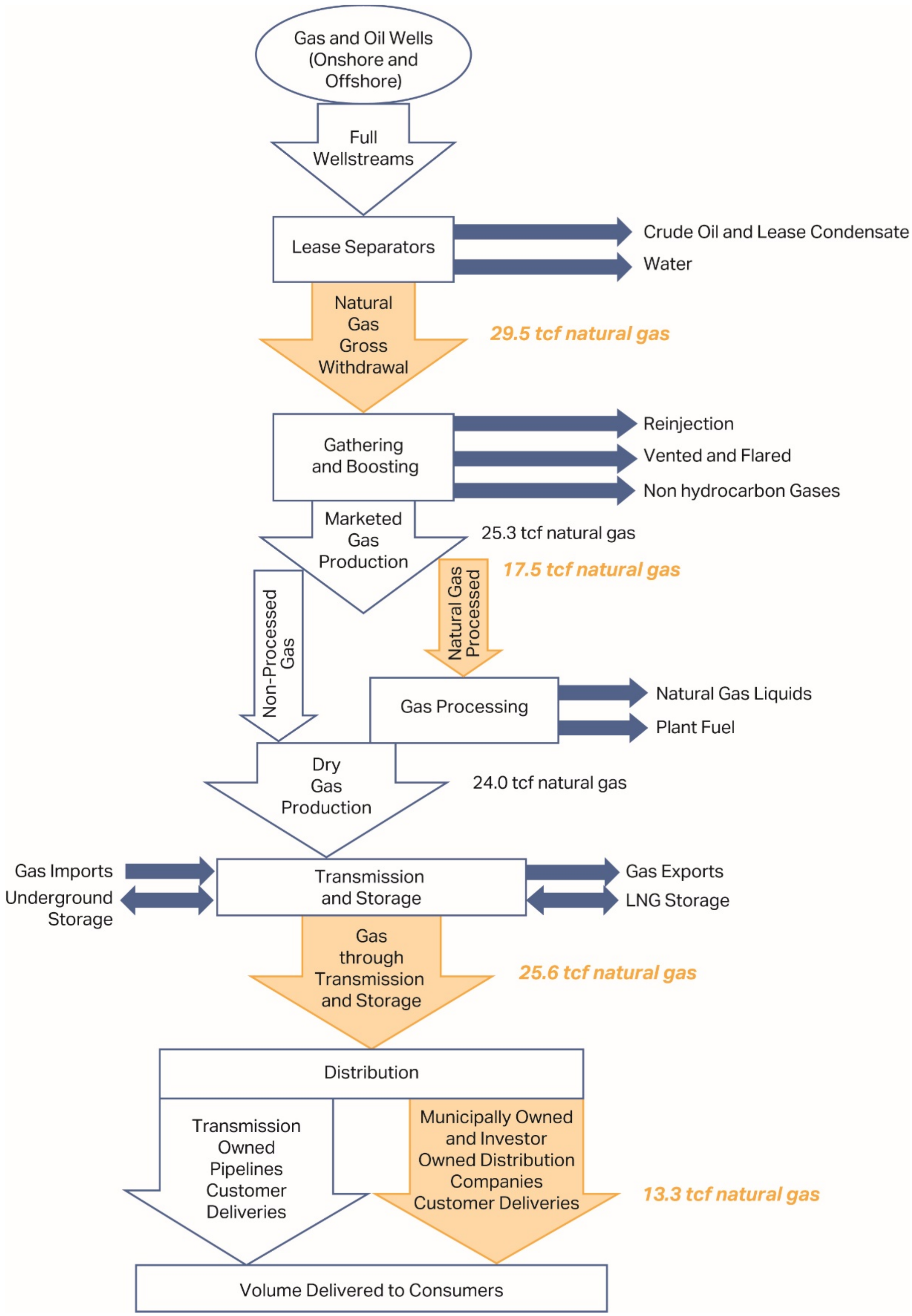

Figure C.2. 2012 Natural Gas Volume through Natural Gas Value Chain

Segment throughputs are noted in bold yellow font, shading indicates the corresponding point in the value chain.

C.2 Emissions Allocations

C.2.1 Co-Production Allocation Methods

Allocation methods are commonly used in the analysis of emissions from value chains when multiple products are produced. For the case of a natural gas well that also produces hydrocarbons that will eventually be separated into pipeline quality natural gas, natural gas liquids, and liquid hydrocarbon products, emissions from devices that handle all the products (e.g., a separator), should be allocated among the multiple products. The most commonly used allocation methods are based on energy, mass, and economic value (Zavala-Araiza, 2015).

The gas leaving a well site will typically contain quantities of ethane, propane, butane, and heavier hydrocarbons and non-hydrocarbons. A large portion of these other gas products are removed from the CH_4 in the gas before the product is supplied as "salable" or "dry" natural gas. Emissions from well sites will therefore be split and allocated to liquid products as well as to natural gas.

The emissions from onshore U.S. production operations will then be attributed to three main products:

(1) Salable natural gas (also known as dry natural gas, referring to the remaining gas once the liquefiable hydrocarbon portion has been removed);
(2) Natural gas liquids, which will be assumed to be the remainder of the hydrocarbon gas leaving the well (lease condensate), and
(3) Hydrocarbon liquids (crude).

Emissions for each product can be allocated based on mass, energy or economic value for each product (salable natural gas, lease condensates, and crude), for each upstream participant company in ONE Future. Since economic value changes as commodity prices change, and since ONE Future is a multi-year program, this ONE Future protocol will not use economic value. For simplicity, allocation by energy is used.

C.2.2 Emissions Allocation between Production and Gathering and Boosting

In the April 2016 GHGI (reporting 2014 national GHG emissions data), the Gathering and Boosting segment was first introduced into the national natural gas systems GHG inventory with specific emission sources separate from natural gas production operations. Prior to that time, emission sources from gathering and boosting operations and production operations were combined.

A field study conducted in 2014 targeted CH_4 emission measurements for natural gas gathering and boosting facilities.[39] The Supplemental Information from that study provides a comparison of the study's measurements to emission sources embedded in the GHGI using calendar year 2012 emissions data from the GHGI.[40] This document was used to split methane emissions

[39] Marchese, et al. *Methane Emissions from United States Natural Gas Gathering and Processing*, Environmental Science & Technology 2015 49 (17), 10718-10727. DOI: 10.1021/acs.est.5b02275
[40] Marchese, et al. *Methane Emissions from United States Natural Gas Gathering and Processing*, Environmental Science & Technology 2015 49 (17), 10718-10727. DOI: 10.1021/acs.est.5b02275, Table S8.

between the Production and Gathering and Boosting segments for the 2012 data. The results are shown in Table C.3.

Table C.3. 2012 Methane Emissions Attributed to the Production vs. Gathering and Boosting Segments

Emission Source	Net Emissions for Production Facilities, Tonnes CH_4	Net* Emissions for Gathering and Boosting Facilities, Tonnes CH_4
Vented Emission Sources		
Drilling and Well Completion	136,974	
Liquids Unloading	171,377	
Pneumatic Device Vents	296,199	38,220
Chemical Injection Pumps	51,394	13,147
Kimray Pumps	224,092	19,227
Dehydrator Vents	75,705	6,495
Condensate Tank Vents without Control	123,057	4,343
Condensate Tank Vents with Control	36,262	1,278
Vessel Blowdowns	457	4
Compressor Blowdowns	524	1,204
Compressor Starts	1,636	3,986
Pipeline Blowdowns		1,754
Mishaps (Pipeline dig-ins)	13	940
Pressure Relief Valves	461	6
Produced water from coal bed methane	37,602	
Offshore Platforms	181,054	
Fugitive Emission Sources		
Wells	33,617	
Heaters	19,997	841
Separators	65,230	1,637
Dehydrators	18,924	1,624
Meters/Piping	64,232	2,318
Small Reciprocating Compressors	12,760	31,619
Large Reciprocating Compressors		9,648
Large Reciprocating Stations		627
Pipeline Leaks		175,500
Combustion Emission Sources		
Compressor Exhaust	36,251	89,545
TOTAL	**1,587,817**	**403,963**

* Total net emissions include source specific reductions specified in the 2012 GHGI Tables A-135 and A-136, and also distributes the unassigned reductions proportionally across all emission sources.

C.2.3 Emissions Allocation for Production

Oil wells can co-produce natural gas. Similarly, natural gas wells produce condensate. To appropriately account for emissions associated with the natural gas value chain, natural gas production operations need to include a portion of emissions associated with gas produced at oil wells and need to be reduced by the portion of emissions attributed to condensate production. Using the energy content of the various streams, emissions are allocated based on the ratio of energy associated with the gas produced divided by the total energy from all produced streams.

The energy equivalents of gas and crude produced from oil wells based on 2012 production data are shown in Table C.4. Note, the EIA definition of crude oil includes lease condensate[41], so the energy content in the denominator is reduced by the energy attributed to lease condensate.

Table C.4. Emission Allocation Basis for Petroleum Production

2012 Production Data		Comments and Data Source
Gas produced from oil wells	4,965,833 MMscf	EIA, Natural Gas Summary http://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_nus_a.htm
BTU equivalent for gas produced from oil wells	6,132,803,755 MMBtu	Applies a raw gas higher heating value of 1235 Btu/scf from API Compendium Table 3-8.
Crude oil production	2,370,114 k bbls	EIA, Crude Oil Production http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm
BTU equivalent for crude oil production	13,746,661,200 MMBtu	Applies a crude oil heating value of 5.8 MMBtu/bbl from API Compendium Table 3-8. This is consistent with the heating value used in GHGRP Table C-1.
Lease condensate production	274,000 k bbls	EIA, Lease Condensate Production http://www.eia.gov/dnav/ng/ng_prod_lc_s1_a.htm
BTU equivalent for lease condensate	1,589,200,000 MMBtu	Applies a crude oil higher heating value of 5.8 MMBtu/bbl from API Compendium Table 3-8. This is consistent with the heating value used in GHGRP Table C-1.
Co-produced gas ratio on an energy equivalent basis $\frac{MMBtu_{gas\ from\ oil\ wells}}{MMBtu_{gas\ from\ oil\ wells} + (MMBtu_{Crude} - MMBtu_{condensate})}$	33.5%	

As a result of the ratio of energy associated with gas produced from oil wells relative to the total energy produced from oil wells, 33.5% of CH_4 emissions from oil wells will be attributed to the natural gas value chain. This allocation is applied to emission sources that handle both oil and gas streams in the Petroleum Production Segment. Emissions from compressors in the petroleum segment, that handle only natural gas, are not adjusted. In addition, all emissions from associated gas venting and flaring are assigned to the natural gas segment. Table C.5 shows the CH_4 emissions from EPA's 2012 GHGI for Petroleum Systems (from Table A-147). The total emissions are shown in addition to the emissions allocated to the natural gas value chain.

[41] EIA defines crude oil as: A mixture of hydrocarbons that exists in liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. Depending upon the characteristics of the crude stream, it may also include: small amounts of hydrocarbons that exist in gaseous phase in natural underground reservoirs but are liquid at atmospheric pressure after being recovered from oil well (casinghead) gas in lease separators and are subsequently commingled with the crude stream without being separately measured. Lease condensate recovered as a liquid from natural gas wells in lease or field separation facilities and later mixed into the crude stream is also included; small amounts of non-hydrocarbons produced with the oil, such as sulfur and various metals; drip gases, and liquid hydrocarbons produced from tar sands, oil sands, gilsonite, and oil shale. http://www.eia.gov/dnav/pet/TblDefs/pet_crd_crpdn_tbldef2.asp

Table C.5. Allocation of CH_4 Emissions from Petroleum Production to the Natural Gas Value Chain

Emission Source	2012 GHGI CH_4 Emissions from Petroleum Production	
	Total Net Emissions*, Tonnes CH_4	Allocated Net Emissions, Tonnes CH_4
Vented Emission Sources		
Oil Well Completion Venting	215	72
Oil Well Workovers	72	24
Stripper Wells	13,792	4,620
Pneumatic Controller Vents	422,318	141,477
Chemical Injection Pump Vents	48,505	16,249
Storage Tanks Vents	259,272	86,856
Associated Gas Venting**	**114,984**	**114,984**
Vessel Blowdowns	277	93
Compressor Blowdowns	**182**	**182**
Compressor Starts	**407**	**407**
Pressure Relief Valves	128	43
Mishaps (Well Blowouts)	2,764	926
Offshore Platforms (GOM and Pacific)	591,854	198,271
Fugitive Emission Sources		
Well site Fugitive Emissions	48,064	16,101
Reciprocating Compressors	**1,759**	**1,759**
Pipeline Leaks	0	0
Combustion Emission Sources		
Compressor Exhaust	**72,857**	**72,857**
Heaters	23,048	7,721
Well Drilling Engines	813	272
Associated Gas Flaring**	**24,754**	**24,754**
Flaring	115	39
TOTAL	**1,626,180**	**687,707**

Emission sources in blue, bold font are sources where all emissions are allocated to the natural gas segment.

* Total net emissions distributes the unassigned voluntary emission reductions reported in the 2012 GHGI (Table A-147) proportionally across all emission sources.

** Associated gas emissions are not reported in the April 2014 GHGI. Emissions shown are from the GHGRP for reporting year 2012, data released November 2015.

As indicated above, the natural gas Production Segment emissions need to be reduced by the portion of emissions attributed to condensate production. The EIA reports annual production of lease condensate[42], defined by EIA as a mixture consisting primarily of pentanes and heavier hydrocarbons, which is recovered as a liquid from natural gas in lease separation facilities. Lease condensate excludes natural gas plant liquids, such as butane and propane, which are recovered at downstream natural gas processing plants or facilities. Table C.6 shows the energy equivalents of natural gas and condensate produced from natural gas wells for 2012.

[42] http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm

Table C.6. Emission Allocation Basis for the Condensate Production

2012 Production Data		Comments and Data Source
Gross natural gas withdrawals less gas from oil wells = total natural gas production	24,576,480 MMscf	EIA, Natural Gas Summary http://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_nus_a.htm
BTU equivalent of produced gas	30,351,952,800 MMBtu	Applies a raw gas higher heating value of 1235 Btu/scf from API Compendium Table 3-8.
Lease condensate production	274 MM bbls	EIA, Lease Condensate Production http://www.eia.gov/dnav/ng/ng_prod_lc_s1_a.htm
BTU from condensate production	1,589,200,000 MMBtu	Applies a crude oil higher heating value of 5.8 MMBtu/bbl from API Compendium Table 3-8. This is consistent with the heating value used in GHGRP Table C-1.
Condensate ratio on an energy equivalent basis $\frac{MMBtu_{condensate\ from\ gas\ wells}}{MMBtu_{condensate} + MMBtu_{produced\ gas}}$	4.98%	

Based on the condensate energy ratio shown in Table C.6, 5% of CH_4 emissions from natural gas production sources that handle both gas and condensate are subtracted from the natural gas value chain. This allocation is applied to most CH_4 emission sources in the natural gas Production Segment. The exceptions are emission sources that handle only gas: dehydrators, Kimray pumps, compressor sources, pipeline sources, and coal bed methane produced water. For these sources, all of the emissions are assigned to the natural gas value chain. Table C.7 shows both the total CH_4 emissions from EPA's 2012 GHGI (Table A-125) for Natural Gas Systems and the emissions allocated to the natural gas value chain.

Table C.7. Allocation of CH_4 Emissions from Condensate Production from the Natural Gas Value Chain

Emission Source	2012 GHGI CH_4 Emissions from Natural Gas Production Total Net Emissions*, Tonnes CH_4	Allocated Net Emissions, Tonnes CH_4
Vented Emission Sources		
Gas Well Completions and Workovers with Hydraulic Fracturing	136,022	129,221
Gas Well Completions and Workovers without Hydraulic Fracturing	341	324
Well Venting for Liquids Unloading with plunger lift	74,488	70,763
Well Venting for Liquids Unloading without plunger lift	96,889	92,044
Pneumatic Controller Vents	296,199	281,389
Chemical Injection Pump Vents	51,394	48,824
Dehydrator Vents	**75,705**	**75,705**
Kimray Pumps	**224,092**	**224,092**
Storage Tanks Vents	159,319	151,353
Well Drilling	611	581
Vessel Blowdowns	457	434
Compressor Blowdowns	**524**	**524**
Compressor Starts	**1,636**	**1,636**
Pressure Relief Valves	461	438
Produced Water from CBM	**37,602**	**37,602**
Offshore Platforms (GOM and Pacific)	181,054	172,002
Fugitive Emission Sources		
Well site Fugitive Emissions	202,000	191,900
Centrifugal Compressors	**0**	**0**
Reciprocating Compressors	**12,760**	**12,760**
Combustion Emission Sources		
Compressor Exhaust	**36,251**	**36,251**
TOTAL	**1,587,817**	**1,527,854**

Emission sources in blue, bold font are sources where all emissions are allocated to the natural gas segment.

* Total net emissions include source specific reductions specified in the 2012 GHGI Tables A-135 and A-136, and also distributes the unassigned reductions proportionally across all emission sources.

Combining the allocated emissions shown in Table C.5 (687,707 tonnes CH_4 from oil production) and Table C.7 (1,527,854 tonnes CH_4 from natural gas production) results in 2,215.6 Gg total CH_4 emissions allocated to the natural gas value chain. These emissions are reflected in the methane intensity values shown in Figure C.1 and Section C.1.

C.2.4 Emissions Allocation for Processing

The Gas Processing Segment also handles both gas and liquid streams. Therefore, GHG emissions from gas processing operations need to be allocated between processing gas streams and processing liquids produced with natural gas. EIA reports natural gas plant liquids (NGPL) on an equivalent gas volume basis (MMscf).[43] Based on the definition of Lease Condensate (refer to Section C.2.3), NGPL are recovered downstream of the gas processing plant. Therefore, emissions from gas processing should be reduced by the amount of CH_4 allocated to the NGPL. Table C.8 shows the energy equivalents for natural gas processed and natural gas plant liquids for 2012 used to compute the emission allocation.

Table C.8. Emission Allocation Basis for the Natural Gas Processing

2012 Processing Data		Comments and Data Source
Total natural gas processed	17,538,026 MMscf	EIA, Natural Gas Summary http://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_nus_a.htm
BTU equivalent of processed gas	17,888,786,520 MMBtu	Applies a processed gas higher heating value of 1020 Btu/scf from API Compendium Table 3-8. (Note, GHGRP Table C-1 provides a natural gas heating value of 1026 Btu/scf)
Natural Gas Plant Liquids (NGPL) production	1,250,012 MMscf	EIA, NGPL Production http://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_nus_a.htm
BTU from NGPL production	3,145,030,192 MMBtu	Applies a higher heating value for propane gas of 2516 Btu/scf from API Compendium Table 3-8. Based on the definition of Lease Condensate provided in Section C.2.2, NGPL consist of butane and propane and are expressed on a gas volume basis.
Ratio on an energy equivalent basis $\frac{MMBtu_{NGPL}}{MMBtu_{NGPL} + MMBtu_{processed\ gas}}$	14.95%	

For 2012, 15% of the total volume of gas processed is attributed to NGPL and 85% of the volume is attributed to natural gas processing. Emissions from the Gas Processing segment are reduced by 15% (13.4 Gg CH_4) to remove emissions associated with processing NGPL for emission sources handling wet gas. No allocation is applied to emissions from equipment handling only gas streams: compressor sources, dehydrator sources, and acid gas removal (AGR) units. This is reflected in the emissions data for Gas Processing shown in Table C.9 and results in 891.2 Gg total CH_4 emissions allocated to the natural gas value chain for Gas Processing for 2012.

[43] http://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_nus_a.htm

Table C.9. Allocation of CH_4 Emissions from Gas Processing to the Natural Gas Value Chain

Emission Source	2012 GHGI CH_4 Emissions from Natural Gas Processing	
	Total Net Emissions*, Tonnes CH_4	Allocated Net Emissions, Tonnes CH_4
Vented Emission Sources		
Pneumatic Controller Vents	1,657	1,409
Dehydrator Vents	**14,570**	**14,570**
Kimray Pumps	**4,319**	**4,319**
AGR Vents	**11,322**	**11,322**
Blowdowns/Venting	40,848	34,720
Fugitive Emission Sources		
Plant Fugitive Emissions	29,033	24,678
Reciprocating Compressors	**381,554**	**381,554**
Centrifugal Compressors	**242,794**	**242,794**
Combustion Emission Sources		
Gas Engines	**160,989**	**160,989**
Gas Turbines	**4,534**	**4,534**
Flares**	12,169	10,343
TOTAL	**903,787**	**891,231**

Emission sources in blue, bold font are sources where all emissions are allocated to the natural gas segment.

* Total net emissions include source specific reductions specified in the 2012 GHGI Tables A-135 and A-136, and also distributes the unassigned reductions proportionally across all emission sources.

** Flare emissions are not included in the GHGI. 2012 emissions reported through the GHGRP are included.

Appendix D: Calculation of Annual ONE Future Methane Intensities

D.1 Production Methane Intensities

This section outlines the approach participating companies will use in allocating their production emissions to the Natural Gas Value Chain and calculating the production segment methane intensity.

Table D.1 summarizes the Production emission sources that are reported through the GHGRP or are calculated using the same GHGRP approaches and indicates how each source is allocated to the Natural Gas Value Chain.

Table D.1. Allocation Methods for Production Segment CH_4 Emission Sources

Production Emission Sources	Allocation to Natural Gas Systems	
	All Gas	Energy Ratio
Vented Emission Sources		
Gas Well Completions and Workovers with HF	✓	
Gas Well Completions and Workovers w/out HF	✓	
Oil Well Completion and Workovers with HF		✓
Liquids unloading with plunger lifts	✓	
Liquids unloading without plunger lifts	✓	
Pneumatic Device Vents		✓
Chemical Injection Pumps		✓
Dehydrators	✓	
Tank Flashing Losses		✓
Tank Vent Malfunctions		✓
Associated Gas Venting/Flaring	✓	
Well Testing		✓
Offshore Production Emissions		✓
Acid Gas Removal Units	✓	
Fugitive Emission Sources		
Well site fugitive emissions		✓
Centrifugal Compressors	✓	
Reciprocating Compressors	✓	
Combustion Emission Sources		
Internal fuel combustion units of any heat capacity that are compressor-drivers	✓	
Other Combustion Emissions		✓
Flaring Emissions		✓

Companies must also quantify emissions for sources that are included in the GHGI but are not reported through the GHGRP. The allocation approaches for these CH_4 emission sources are shown in Table D.2. Data requirements to quantify these emissions are also indicated.

Table D.2. Allocation Methods for Production Segment CH_4 Emission Sources in the GHGI

Production Emission Sources	Allocation to Natural Gas Systems		Data Requirements
	All Gas	Energy Ratio	
Vented Emission Sources			
Well Drilling		✓	Number of wells drilled
Vessel Blowdowns		✓	Number of separators, heater-treaters, dehydrators, and in-line heaters
Compressor Blowdowns	✓		Total number of compressors
Compressor Starts	✓		Total number of compressors
Pressure Relief Valves (PRVs)		✓	Number of PRVs
Floating roof tanks		✓	Number of floating roof tanks

The GHGRP does not separately track emissions associated with gas wells versus oil wells, although there are a few emission source types that only apply to either Natural Gas Production or Petroleum Production:

- Completions and workovers without hydraulic fracturing only apply to gas wells.
- Completions and workovers with hydraulic fracturing only apply to gas wells for calendar year 2015 and prior. Starting in 2016, emissions from completions and workovers on oil wells will also be reported.
- Liquids unloading only apply to gas wells.

For the purpose of allocating company CH_4 emissions to track company progress toward their commitments to ONE Future, the following sources are assigned either to Natural Gas Production or Petroleum Production:

- Dehydrators, acid gas removal (AGR) units, and compressors only handle gas streams; therefore, emission sources associated with dehydrators, AGR units, and compressors are assigned to Natural Gas Production.

All remaining sources are included in the Natural Gas Value Chain based on the ratio of energy from gas production to total energy produced.

Allocating company CH_4 emissions based on the energy ratio of produced gas to the total energy produced uses a method similar to the approach outlined in Section C.2.3 for national emission estimates. Company data on the volume of gas produced and the volume of crude production are used to compute a company-specific energy equivalent ratio to allocate emissions from Petroleum Production to the Natural Gas Value Chain. Table D.3 provides the information needed and the equation for developing a company specific energy ratio to allocate emissions at the company level from gas co-produced with oil.

Table D.3. Company Data for Petroleum Production Emission Allocation

Company Production Data	Comments and Default Data Sources
Total volume of gas produced from wells, Mscf	Company-specific data should be used
BTU equivalent for gas produced from oil wells	Company specific data should be used if available. If not available, the raw gas higher heating value of 1235 Btu/scf from API Compendium Table 3-8 can be applied
Total volume of crude produced for sales, bbl	Company specific data should be used
BTU equivalent for crude oil production	Company specific data should be used if available. If not available, the crude oil heating value of 5.8 MMBtu/bbl from API Compendium Table 3-8 can be applied.
Co-produced gas ratio on an energy equivalent basis $\frac{MMBtu_{gas\ from\ oil\ wells}}{MMBtu_{gas\ from\ oil\ wells} + MMBtu_{Crude}}$	Calculate the company specific co-produced gas ratio using this equation.

Although natural gas production operations may also produce condensate, the energy equivalent associated with condensate production is generally small compared to the energy associated with produced natural gas. On a national level, this ratio is about 5% (see Table C.6). To simplify the allocation approach for participant companies, emissions from condensate production are not allocated out of the Natural Gas Value Chain. ONE Future recognizes that this will result in a slight overestimate of company emissions where condensate is produced.

After emission allocation is applied, the allocated CH_4 emissions, on a mass basis, are summed and divided by tonnes of CH_4 produced from wells to yield the non-additive, production segment-specific methane intensity. To convert from the non-additive production segment methane intensity to the additive version, the non-additive methane intensity is multiplied by a ratio of national production segment throughput to national gross gas production. For this segment, the ratio is one-to-one (1:1). The national production segment throughput and the national gross gas production are both equal to EIA's Gross Withdrawals minus Repressuring. This quantity was chosen to represent the gross gas production so that any field use is included while removing the large quantity of gas nationally that is reinjected into the system. This provides the net amount of gas entering the production system. The national quantities and conversion calculation are discussed further in section D.6.

D.2 Gathering and Boosting Methane Intensities

The Gathering and Boosting Segment is very similar to the Production Segment in regards to energy allocation. The gathering and boosting segment does not include all of the sources that production does. However, the sources that gathering and boosting do include follow the methodology shown in Table D.1 as to which sources to apply the energy allocation. Table D.4 shows sources that are included in the GHGI but are not reported through the GHGRP and how allocation should be applied.

Table D.4. Allocation Methods for Gathering and Boosting Segment CH_4 Emission Sources in the GHGI

Gathering and Boosting Emission Sources	Allocation to Natural Gas Systems		Data Requirements
	All Gas	Energy Ratio	
Vented Emission Sources			
Compressor Blowdowns	✓		Total number of compressors
Compressor Starts	✓		Total number of compressors
Gathering Pipeline Dig-ins	✓		Miles of gathering pipeline
Floating roof tanks		✓	Number of floating roof tanks

The gas ratio on an energy equivalent basis for the gathering and boosting segment is very similar to that of the production segment. Though, for the gathering and boosting segment, quantity of gas transferred from the facility and quantity of hydrocarbon liquids transferred from the facility are converted to an energy basis and then plugged in to the ratio equation. If company specific heating values are not provided, the same default values as are shown in Table D.3 can be used.

To calculate the non-additive, gathering and boosting segment-specific methane intensity, divide the allocated CH_4 emissions on a mass basis by the quantity of gas transferred from facilities in tonnes CH_4. Because there are no national data on gathering and boosting throughput, it is assumed that the gathering and boosting segment is integrally linked with the production segment and handles the exact same gas. Therefore, the same ratio of EIA's gross withdrawals minus repressuring over gross withdrawals minus repressuring (a ratio of 1:1) as is described in section D.1 is used to convert the non-additive gathering and boosting methane intensity to the additive version of the methane intensity.

D.3 Processing Methane Intensities

For the Gas Processing Segment, the allocation methods outlined in Section C.2.4 can be applied at the company level. Company data on the volume of gas processed and the volume of natural gas plant liquids (NGPL) are used to compute a company-specific energy equivalent ratio to remove emissions associated with NGPL from the Natural Gas Value Chain. Table D.5 provides the information needed and the equation for developing a company-specific ratio to allocate emissions at the company level from NGPL.

Table D.5. Company Data for Natural Gas Processing Segment Emission Allocation

Company Processing Data	Comments and Data Source
Total natural gas processed, Mscf	Company-specific data should be used
BTU equivalent of processed gas	Company specific data should be used if available. If not available, the processed gas higher heating value of 1020 Btu/scf from API Compendium Table 3-8 can be applied
Natural Gas Plant Liquids (NGPL) production, bbls	Company-specific data should be used
BTU from NGPL production, bbl	Company specific data should be used if available. If not available, the higher heating value for propane gas of 3.82 MMBtu/bbl from API Compendium Table 3-8 can be applied.

Company Processing Data	Comments and Data Source
Ratio on an energy equivalent basis $\frac{MMBtu_{processed\ gas}}{MMBtu_{NGPL} + MMBtu_{processed\ gas}}$	Calculate the company specific gas ratio using this equation.

The gas ratio should be applied to the Gas Processing emission sources as indicated in Table D.6. The table indicates the emission data that should be applied to each source based on whether the emission source is reported through the GHGRP or must be estimated from a GHGI emission factor. No allocation is applied to emissions from equipment handling only gas streams in the processing facility: compressor sources, dehydrator sources, and AGR units.

Table D.6. Allocation of Company CH_4 Emissions from Gas Processing from the Natural Gas Value Chain

Emission Source	Data source for Company Net CH_4 Emissions	Allocation
Vented Emission Sources		
Pneumatic Controller Vents	GHGI emission factor	Apply the gas ratio
Dehydrator Vents	GHGRP data	100% is allocated to the Natural Gas Value Chain
AGR Vents	GHGI emission factor	
Blowdowns/Venting	GHGRP data	Apply the gas ratio
Fugitive Emission Sources		
Plant Fugitive Emissions	GHGRP data	Apply the gas ratio
Reciprocating Compressors	GHGRP data	100% is allocated to the Natural Gas Value Chain
Centrifugal Compressors	GHGRP data	
Combustion Emission Sources		
Compressor Engine Exhaust	AP-42 emission factor or direct stack test data	100% is allocated to the Natural Gas Value Chain
Flares	GHGRP data	Apply the gas ratio

After emission allocation is applied, the allocated CH_4 emissions, on a mass basis, are summed and divided by tonnes of CH_4 leaving the gas processing plants to yield the non-additive, processing segment-specific methane intensity. Nationally, quantity of gas processed is directly reported to EIA. So, to convert this non-additive methane intensity to the additive processing segment methane intensity, multiply by the ratio of EIA natural gas processed over national gross gas production. As was mentioned in the previous sections, national gross gas production is equal to EIA's gross withdrawals minus repressuring.

D.4 Transmission and Storage Methane Intensities

Because allocating emissions is not necessary for the transmission and storage segment, this section will focus on discussing transmission and storage throughputs. Gas transported in the U.S. is reported using EIA form 176. However, separate forms must be submitted when the natural gas crosses state lines and when it changes hands between companies. So, for a single pipeline that crosses several state boundaries, there could be several reports submitted for the same quantity of gas. Therefore, there is some double counting of gas transported when all EIA 176 forms are added nationally. This is shown in DOE's EIA Natural Gas Annual Report, which shows more gas reported as transported than total gas produced that enters into the system.[44] In order to avoid this double counting, ONE Future creates a surrogate throughput using a simple ratio to pipeline mileage, since mileage is known not to be double counted.

D.4.1 Surrogate Miles-Based Throughput

Surrogate Miles-Based Throughput reported by ONE Future transmission and storage companies is adjusted using a ratio of national throughput to national pipeline mileage and ONE Future pipeline mileage. National transmission system throughput also has to be estimated, as there is no single value reported in DOE's Natural Gas Annual Report for this. ONE Future has estimated the transmission system national throughput as the EIA dry gas production plus net imports plus net storage withdrawals. This value is then part of the national ratio of transmission throughput to national miles.

A company's estimated throughput based on pipeline miles is then used as the divisor in the methane intensity calculation for this segment. The pipeline mileage adjustment to the gas throughput is shown in equation D-1. Example 3 illustrates the calculation for a hypothetical transmission and storage company.

$$TP_{C,adj} = \frac{V_N}{M_N} \times M_C \times \frac{1{,}000\ scf}{Mscf} \times 0.934 \times \frac{0.0192\ kg/scf}{1{,}000\ kg/tonne}$$

(Equation D-1)

Where:

$TP_{C,adj}$	=	Mileage adjusted transmission throughput, tonnes CH_4
V_N	=	EIA volume of gas transported (dry gas production + net imports + net storage withdrawals), Mscf
M_N	=	National transmission pipeline mileage (all companies), miles[45]
M_C	=	Company transmission pipeline mileage, miles
0.934	=	Default methane composition for the transmission and storage segment
0.0192	=	Methane density, kg/scf

[44] DOE's EIA Natural Gas Annual Report indicates more gas reported as transported than the total produced gas entering the system. In Table 1, under the Production section in 2018, the total dry produced gas entering the system is expressed as 30,588,702 million cubic feet. The Supply & Distribution by State section in 2018 expresses the total interstate deliveries to be 68,941,650 million cubic feet, indicating the total supply of gas to be greater than the total gas produced in the U.S. in 2018.

[45] National pipeline mileage is pulled from PHMSA.

EXAMPLE 3

Hypothetical Company A operates several transmission pipeline facilities, transmission compression facilities and storage stations. Company-specific and national data are shown in the tables below:

Calculate the pipeline mileage-adjusted throughput by applying Equation D-1 with the data provided below:

CY2018	Miles of transmission pipeline	Gas transported, Mscf
Company A Data	26,884	3,500,000,000[46]
National Data	298,298	30,193,642,000

A national average amount of gas transported per mile is calculated, and that ratio is applied to the company mileage to get a surrogate company throughput. The calculation below is broken into two steps to show Company A's gas transported in Mscf and in tonnes CH_4.

$$TP_{C,adj} = \frac{30{,}193{,}642{,}000}{298{,}298} \times 26{,}884$$

$$= 2{,}721{,}191{,}129\ Mscf$$

$$TP_{C,adj} = 2{,}721{,}191{,}129 \times \left(1000 \times 0.934 \times \left(\frac{0.0192}{1000}\right)\right)$$

$$= 48{,}798{,}576\ tonnes\ CH_4$$

Divide the company methane emissions, provided below, by the pipeline mileage-adjusted throughput to calculate Company A's methane intensity:

Company A	Methane Emissions, tonnes CH_4
GHGRP Facilities	29,472
Non-GHGRP Facilities	3,838

$$\frac{E_C}{TP_{C,adj}} = \frac{33{,}310}{48{,}798{,}576} = 0.0683\%$$

Example 3, above, shows how to use this pipeline mileage-adjusted throughput to calculate a single transmission company's methane intensity. To calculate ONE Future's non-additive,

[46] This is a hypothetical summary of EIA 176 filings for this company, which overestimates actual net throughput. Therefore, a single counted throughput value is calculated later in this example: 2.721 Tcf

transmission and storage segment-specific methane intensity, all ONE Future companies' emissions must be added then divided by the sum of the companies' throughputs. Further, to convert the non-additive methane intensity to the additive version of the transmission and storage methane intensity, multiply by the ratio of national transmission throughput over national gross gas production. The national transmission throughput, as is mentioned earlier in this section, is EIA dry gas production plus net imports plus net storage withdrawals. Example 5 in section D.6 shows this calculation of the additive segment methane intensity. The mileage-adjusted throughput approach is used to calculated the additive T&S segment methane intensity that is presented in the annual ONE Future Methane Intensities Report.

D.4.2 Company-Specific PHMSA Throughput-Based Approach

This section will discuss an alternate way to calculate company-specific methane intensities for members that report T&S assets to ONE Future. This approach is only applicable to company-specific T&S methane intensities and *is not used in any way in the annual ONE Future Methane Intensities Report.* It is presented here solely as an alternate way that a company may calculate their own specific methane intensity. The resulting methane intensity can be compared to the ONE Future surrogate miles-based company-specific methane intensity.

Throughput reported by T&S companies to the U.S. Pipeline and Hazardous Materials Safety Administration (PHMSA) can also be used to calculate a company's non-additive methane intensity. Part C onshore natural gas volume transported, reported in million standard cubic feet of natural gas, from PHMSA form F 7100.2-1 can be used in the denominator of the methane intensity calculation for a given company. Some companies have found this to be a relevant metric for their own internal company uses.

D.5 Distribution Methane Intensities

The throughput volume for the Distribution segment is based on the volume of natural gas delivered to consumers from municipally owned and investor owned distribution companies. These volumes are determined from EIA Form 176.[47] In addition, participant throughput is normalized for weather fluctuations using state-specific Heating Degree Days (HDD)[48] values for the residential and commercial consumers. Gas throughput is variable based on weather fluctuations for residential and most commercial meters. However, methane emissions are not directly correlated to throughput. As a result, applying throughput to the denominator for quantifying company methane intensities results in a methane intensity biased low for northern climate utilities (where emissions are divided by a higher throughput) and biased high for southern climate utilities. Normalizing residential and commercial meter throughput for HDDs removes this bias from the participant throughputs.

[47] http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RP1
[48] An HDD is the number of degrees that the average temperature in an area is below 65 degrees F. For example, if the average temperature on a January day in New York is 35F, it creates 30 HDDs for that day. If on the same day in January, it was 75F in Miami, 0 HDDs would apply to that distribution company (no negative numbers are used).

HDD data are published by the National Oceanic and Atmospheric Administration (NOAA), Climate Prediction Center (CPC)[49]. NOAA CPC reports monthly HDD values that are population-weighted by state. Cumulative data are aggregated annually from July 1st to June 30th. For example, the average HDD for reporting year 2017 would use the July 2016-June 2017 data for the states of interest. The HDD adjustment to the volume of gas delivered is shown in Equation D-2. Example 4 illustrates the calculation for a hypothetical LDC.

$$HDD\ V_{State\ i} = \left(V_{Res,i} + V_{Comm,i}\right) \times \frac{US\ HDD}{State_i\ HDD} + V_{Total,i} - \left(V_{Res,i} + V_{Comm,i}\right)$$

(Equation D-2)

where:

HDD $V_{State,\ i}$	=	HDD Adjusted natural gas volume delivered by the LDC for state "i" in the reporting year, Mscfy
$V_{Res,i}$	=	Volume of gas delivered by the LDC to residential customers in state "i" for the reporting year, Mscfy
$V_{Comm,i}$	=	Volume of gas delivered by the LDC to commercial customers in state "i" for the reporting year, Mscfy
US HDD	=	Average HDD for the U.S. for a given reporting year
$State_i$ HDD	=	Average HDD for state "i" for a given reporting year
$V_{Total,\ i}$	=	Total volume of gas delivered to all customers by the LDC in state "i" for the reporting year, Mscfy

[49] ftp://ftp.cpc.ncep.noaa.gov/htdocs/products/analysis_monitoring/cdus/degree_days/archives/Heating%20degree%20Days/monthly%20states/2017/Jun%202017.txt

EXAMPLE 4

A hypothetical LDC operates in Texas and New Mexico. Gas delivery volumes for reporting year 2016 are shown in the table below.

		Mscf Delivered
Texas	Residential Customers Commercial Customers Total Volume to all Customers	25,000,000 15,000,000 55,000,000
New Mexico	Residential Customers Commercial Customers Total Volume to all Customers	12,000,000 2,000,000 18,000,000

Using NOAA CDC data, the 2016 state and national cumulative HDD values are:

- Texas = 1135
- New Mexico = 3433
- US Total = 3626

Applying Equation D-2, the HDD adjusted volume for Texas is:

$$HDD\ V_{Texas} = (25{,}000{,}000 + 15{,}000{,}000) \times \frac{3626}{1135} + 55{,}000{,}000 - (25{,}000{,}000 + 15{,}000{,}000)$$

= 142,788,546 Mscf

Applying Equation D-2, the HDD adjusted volume for New Mexico is:

$$HDD\ V_{New\ Mexico} = (12{,}000{,}000 + 2{,}000{,}000) \times \frac{3626}{3433} + 18{,}000{,}000 - (12{,}000{,}000 + 2{,}000{,}000)$$

= 18,787,067 Mscf

Once the weather normalized volumes are calculated, the volumes can be converted to a mass of CH_4 basis. Next, by dividing the distribution emissions by the weather normalized throughput, the non-additive distribution segment methane intensity is found. Finally, to calculate the additive distribution segment methane intensity, multiply the non-additive methane intensity by the national distribution throughput divided by the national gross gas production. The national distribution throughput is the sum of EIA gas delivered to residential, commercial, and industrial consumers.

D.5.1 Underground Storage and LNG Storage

Starting in CY2022, underground natural gas storage and LNG storage facilities were included with either the T&S segment or the Distribution segment. In previous years, all underground and

LNG storage assets were included solely in the T&S segment as a default. These storage facilities are now being separated between the T&S and Distribution segments based on the segment in which they are physically located and operated.

D.6 Emissions per Throughput

Emissions per throughput at both the segment level (Es/TPs) and for the ONE Future companies (Ec/TPc) is calculated in a similar manner, as shown in Equations D-3 and D-4, respectively.

$$Avg\,\frac{E_{Companies}}{TP_{Companies}}$$

$$= \frac{\sum_{n=1}^{Company_i} Company\ emissions\ for\ segment\ (tonnes\ CH_4)}{\sum_{n=1}^{Company_i} Company\ throughput\ for\ segment\ (MMscf)}$$

$$\times \frac{MMscf\ gas\ emissions}{10^6 scf\ gas} \times \frac{scf\ gas}{1.198\ gmol\ gas}$$

$$\times \frac{(gmol\ Natural\ Gas)}{Segment\ average\ CH_4\ content\ (gmol\ CH_4)} \times \frac{gmol\ CH_4}{16\ g\ CH_4} \times \frac{10^6 g\ CH_4}{tonnes\ CH_4}$$

(Equation D-3)

$$\frac{E_{Company}}{TP_{Company}} = \frac{net\ Company\ emissions\ for\ segment\ (tonnes\ CH_4)}{Company\ throughput\ for\ segment\ (MMscf)}$$

$$\times \frac{MMscf\ gas\ emissions}{10^6\ scf\ gas} \times \frac{scf\ gas}{1.198\ gmol\ gas}$$

$$\times \frac{(gmol\ Natural\ Gas)}{Company\ CH_4\ content\ (gmol\ CH_4)} \times \frac{g\ mole\ CH_4}{16\ g\ CH_4} \times \frac{10^6\ g\ CH_4}{tonnes\ CH_4}$$

(Equation D-4)

The national values used to convert segment methane intensities to additive methane intensities such as in Equation 2 are shown below in Table D.7. Table D.7 also shows these numerical values for CY2018 as an example year.

Table D.7. Data Sources for National Gross Gas Production and National Segment Throughputs

Quantity	Source of Data	CY2018	
		National Value (Tcf Natural Gas)	National Value (Tonnes CH_4)
National Gross Gas Production	EIA Natural Gas Gross Withdrawals minus Repressuring	33.545	528,778,120
National Production Segment Throughput	EIA Natural Gas Gross Withdrawals minus Repressuring	33.545	528,778,120
National Gathering and Boosting Segment Throughput	EIA Natural Gas Gross Withdrawals minus Repressuring	33.545	528,778,120
National Processing Segment Throughput	EIA Natural Gas Processed	22.145	369,915,576
National Transmission and Storage Segment Throughput	EIA Natural Gas Dry Production plus Net Imports plus Net Underground Storage Withdrawals	30.194	541,456,543
National Distribution Segment Throughput	EIA Natural Gas Delivered to Residential, Commercial, and Industrial Consumers	16.889	302,864,692

Table D.8 further shows the normalizing national ratio calculated for the example calendar year 2018 by taking the segment throughput divided by the national gross gas production using the values shown in Table D.7.

Table D.8. Segment Normalizing National Ratios for CY2018

Segment	Normalizing National Ratio[50] for CY2018
Production	$\frac{528{,}778{,}120}{528{,}778{,}120} = 1.00$
Gathering and Boosting	$\frac{528{,}778{,}120}{528{,}778{,}120} = 1.00$
Processing	$\frac{369{,}915{,}576}{528{,}778{,}120} = 0.70$
Transmission and Storage	$\frac{541{,}456{,}543}{528{,}778{,}120} = 1.02$
Distribution	$\frac{302{,}864{,}692}{528{,}778{,}120} = 0.57$

[50] The normalizing national ratio is used to convert the non-additive segment methane intensity to the additive segment methane intensity. This is TP_S/GP from Equation 2.

The following example illustrates the scale-up of emissions from ONE Future participants in the Transmission and Storage segment to a national level. The participant emissions shown are provided as an example only, and do not represent actual participant emissions.

EXAMPLE 5a

For this hypothetical example, the combined CH_4 emissions for participant companies in the Transmission and Storage segment are 12,400 tonnes CH_4. The corresponding company-based segment throughput is 180 Bcf of natural gas with an average CH_4 content of 92%. The segment methane intensity value is calculated by applying Equation D-3, as shown:

$$Avg\,\frac{E_C}{TP_C} = \frac{12{,}400\ tonnes\ CH_4}{180{,}000\ MMscf\ gas} \times \frac{MMscf\ gas}{10^6 scf\ gas} \times \frac{scf\ gas}{0.92\ scf\ CH_4} \times \frac{scf\ CH_4}{1.198\ gmol\ CH_4}$$

$$\times \frac{g\ mole\ CH_4}{16\ g\ CH_4} \times \frac{10^6 g\ CH_4}{tonne\ CH_4} = \frac{0.00391\ tonne\ CH_4\ emissions}{tonne\ CH_4\ gas\ throughput} = 0.391\%$$

Note, the same ratio is produced if expressed on a volume of natural gas basis:

$$Avg\,\frac{E_C}{TP_C} = \frac{12{,}400\ tonnes\ CH_4}{180{,}000\ MMscf\ gas} \times \frac{10^6 g\ CH_4}{tonne\ CH_4} \times \frac{g\ mole\ CH_4}{16\ g\ CH_4} \times \frac{gmol\ Nat.Gas}{0.92\ gmol\ CH_4}$$

$$\times \frac{scf\ gas}{1.198\ gmol\ gas} \times \frac{MMscf\ gas\ emissions}{10^6 scf\ gas}$$

$$= \frac{0.00391\ MMscf\ gas\ emissions}{MMscf\ gas\ throughput} = 0.391\%$$

EXAMPLE 5b

The following illustrates how the segment methane intensity is scaled to a national level and converts the emissions to a gross production basis. These calculations apply Equation D-3 and build on the hypothetical methane intensity for the Transmission and Storage participant companies in Example 5a. For this example, the 2018 national gross production and national throughput for Transmission and Storage are applied. Gross production (EIA Gross Withdrawals minus Repressuring), expressed in terms of tonnes of CH_4, is 528,778,120 as shown in Table D.7. The Transmission and Storage throughput (EIA Dry Production plus Net Imports plus Net Storage Withdrawals) is converted from 30.194 Tcf of gas to 541,456,543 tonnes CH_4 as shown in Table D.7 based on a conversion using an average T&S segment methane concentration of 93.4%.

$$GPI_{T\&S} = \left(SI_p\right)_{T\&S} \times \frac{(TP_s)_{T\&S}}{GP} \qquad \text{(Equation 2)}$$

Where:

$GPI_{T\&S}$	=	ONE Future transmission and storage Gross Production Methane Intensity for the participant companies
$\left(SI_p\right)_{T\&S}$	=	Weighted average participant emissions per participant throughput for the Transmission and Storage Segment
$(TP_s)_{T\&S}$	=	National Transmission and Storage Segment Throughput
GP	=	National Gross Production

$$GPI_{T\&S} = \left(\frac{0.00391\ tonne\ CH_4\ emissions}{tonne\ CH_4\ throughput}\right)_{T\&S\ Participants} \times \frac{541{,}456{,}543\ tonne\ {CH_4}_{T\&S\ national}}{528{,}778{,}120\ tonne\ {CH_4}_{Gross\ Production}} = \frac{0.0040\ tonne\ {CH_4}_{T\&S\ national}}{tonne\ {CH_4}_{Gross\ Production}} = 0.40\%$$